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2019053109S3SH

June 3, 2019

The Honorable Ronald D. Kouchi,
President and Members
of the Senate
Thirtieth State Legislature
State Capitol, Room 409
Honolulu, Hawaii 96813

The Honorable Scott K. Saiki,
Speaker and Members of the
House of Representatives
Thirtieth State Legislature
State Capitol, Room 431
Honolulu, Hawaii 96813

Dear President Kouchi, Speaker Saiki, and Members of the Legislature:

For your information and consideration, I am transmitting a copy of the Utility Model Study as required by Act 124 SLH 2016. In accordance with Section 93-16, Hawaii Revised Statutes, I am also informing you that the report may be viewed electronically at: http://dbedt.hawaii.gov/overview/annual-reports-reports-to-the-legislature/.

With aloha,

Mike

Mike McCartney

Enclosure

c: Legislative Reference Bureau

Evaluation of Utility Ownership and Regulatory Models for Hawaii

prepared for
State of Hawaii Department of Business, Economic Development & Tourism

HAWAII STATE Energy Office

ENERGY.HAWAII.GOV

June 2019

Prepared by

London Economics International LLC
with participation from
Meister Consultants Group,
a Cadmus Company
Yamamoto Caliboso,
a Limited Liability Law Company

DBEDT
STATE OF HAWAII

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List of acronyms

AFR	Annual Financial Reports
AMI	Advanced Metering Infrastructure
B-corp	Benefit corporation
Capex	Capital Expenditures
CFC	Cooperative Finance Corporation
Co-op	Cooperative
COS	Cost of Service
DBEDT	Hawaii Department of Business, Economic Development, and Tourism
DCA	Division of Consumer Affairs
DCF	Discounted Cash Flow
DER	Distributed Energy Resource
DG	Distributed Generation
DSPP	Distributed System Platform Provider
ECAC	Energy Cost Adjustment Clause
EAM	Earnings Adjustment Mechanism
EIA	Energy Information Administration
ERAC	Energy Rate Adjustment Clause
ESM	Earnings Sharing Mechanism
EV	Electric Vehicle
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
G&T	Generation and Transmission
GMP	Green Mountain Power
HECO	Hawaiian Electric Company
HELCO	Hawaii Electric Light Company
HEI	Hawaiian Electric Industries
HERA	Hawaii Electricity Reliability Administrator
HI	Hawaii
IDER	Integrated Distributed Energy Resources
IDSO	Independent Distribution System Operator
IGO	Integrated Grid Operator
IOU	Investor-Owned Utility
IPP	Independent Power Producers
IRP	Integrated Resource Plan
ISO	Independent System Operator
IT	Information Technology
ITC	Investment Tax Credit
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company
NCSC	National Cooperative Services Corporation

NEB	National Energy Board
NERC	North American Electric Reliability Corporation
NWA	Non-Wire Alternative
Ofgem	Office of Gas and Electricity Markets
OPA	Ontario Power Authority
Opex	Operating expenditures
PBR	Performance-based Regulation
PILOT	Payment in Lieu of Taxes
PIM	Performance Incentive Mechanism
PSIP	Power Supply Improvement Plan
PTC	Production Tax Credit
PUC	Hawaii Public Utilities Commission
RAB	Regulatory Asset Base
RAM	Revenue adjustment mechanisms
RBA	Revenue balancing accounts
REV	Reforming the Energy Vision
RIIO	Revenue = Incentives + Innovation + Outputs
ROE	Return on equity
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization
RUS	Rural Utilities Service
SB	Single Buyer
T&D	Transmission and Distribution
TIER	Times Interest Earned Ratio
TNB	Tenaga Nasional Berhad
Totex	Total expenditures
UK	United Kingdom
USDA	United States Department of Agriculture
WACC	Weighted average cost of capital

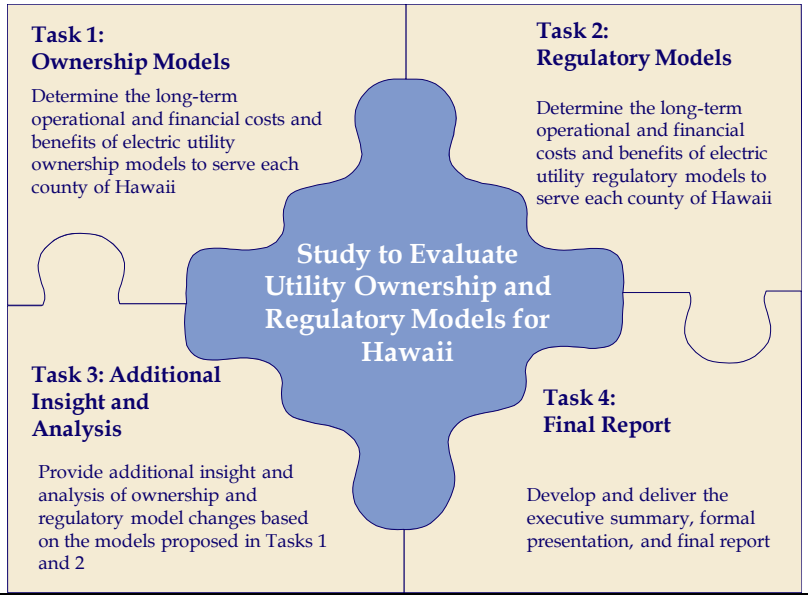
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1 Executive summary

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT"), through House Bill 1700 (Act 124), was directed by the legislature to conduct a "study to evaluate the alternative utility and regulatory models,"[1] (the "Study") and "the ability of each model to: achieve state energy goals; maximize customer cost savings; enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer needs; and eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation."[2] Through a competitive procurement process,[3] London Economics International LLC ("LEI") was awarded the contract for the conduct of the Study in March 2017.

The goal of the Study was to review and perform a thorough assessment of alternative models, laying out the pros and cons of each with respect to State policy objectives so that it could be used as a guide. As there is no single model that is best suited to achieve all objectives, the Study findings can help the legislature and stakeholders weigh alternatives as opposed to prescribe specific utility ownership and regulatory models to be implemented. The detailed discussions of analyses provided in individual task reports, which are summarized in this final report, are intended to provide enough information to assess how changes in assumptions and market conditions could impact the Study's analyses and assessments.

Figure 1. Tasks within the Study scope of work



[1] HB1700, Act 124. Task 7.

[2] Ibid.

[3] Hawaii No. RFP-17-020-SID dated September 30, 2016; Addendum No. 1 dated October 20, 2016; Addendum No. 2 dated October 24, 2016.

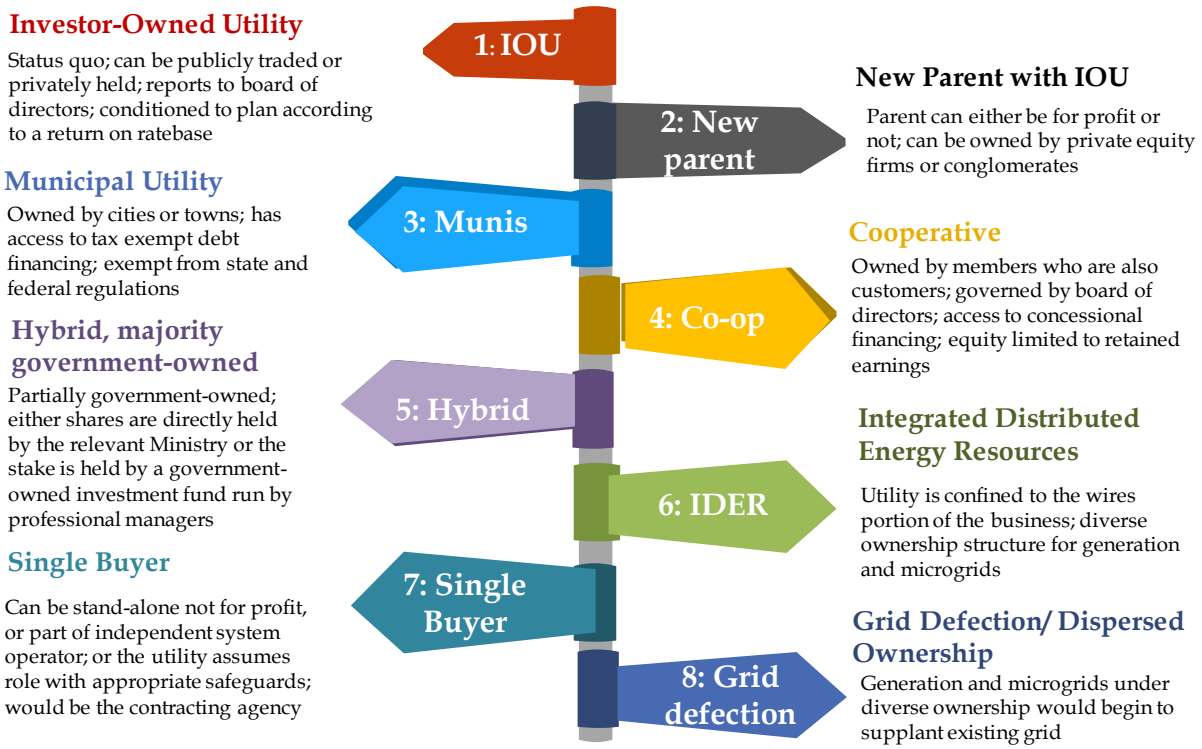
The scope of work is divided into four parts, namely: (i) ownership models; (ii) regulatory models; (iii) additional analyses; and (iv) final report (Figure 1). The evaluation of potential utility ownership and regulatory models was performed through separate analyses but using a similar process and methodology. The Project Team additionally examined whether changes in the rate design could provide the same benefits as changes in the ownership or regulatory models and assessed the advantages and disadvantages of managing the State's electricity sector with each county operating independently versus having a multi-county model.

1.1 Initial evaluation of ownership and regulatory models

The Project Team initially performed a review of eight utility ownership structures (Figure 2) and six regulatory models (Figure 3). Sections 4.1 and 5.1 provide a more detailed discussion of these models.

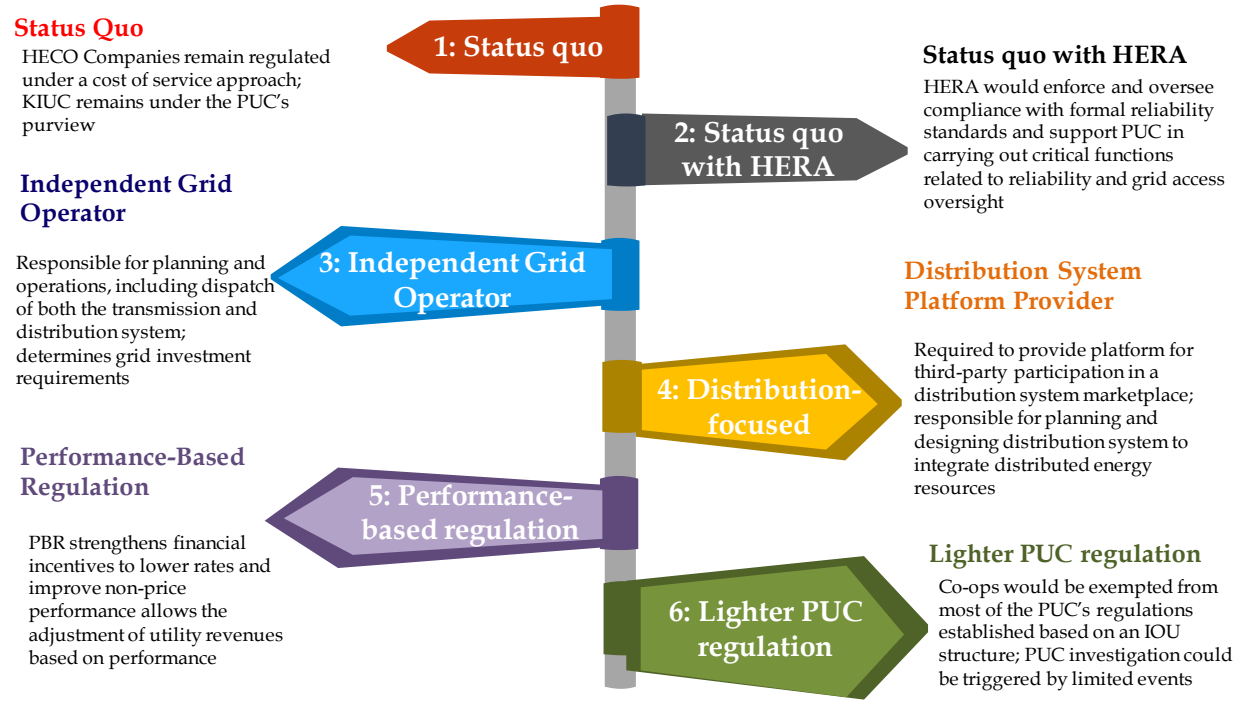
The Project Team conducted high-level analyses to evaluate each model's pros and cons, financial, legal, and operational feasibility, the achievement of the state's policy objectives, and potential stranded costs with the change in the model. It is emphasized that there can be wide variations even within ownership and regulatory structures. The Project Team has described the models in the Study in a way that encompasses the most common forms. However, each model can be further customized to meet the needs of the State of Hawaii or the individual Hawaiian Islands.

Figure 2. Utility ownership models considered in the Study



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Figure 3. Regulatory models considered in the Study



Input from participants to the community dialogues was also taken into account. Three separate trips to each island (Hawaii, Maui, Lanai, Molokai, Oahu, and Kauai islands) were conducted to solicit stakeholders' inputs on the Study: June 2017 (to discuss ownership models); July 2018 (to discuss regulatory models); and November 2018 (to present the preliminary findings). The Project Team also met with various stakeholders including representatives from the utilities, the Division of Consumer Advocate, commissioners, legislators, industry players, and non-government organizations. Moreover, an e-mail address[4] was set up to collect feedback throughout the Study. All comments that were received were read, reviewed, and considered in the Study. Based on the conversations with the participants in these community discussions and one-on-one meetings, lowering electricity rates is the main (but not only) priority of stakeholders.

The Project Team selected six criteria with which to evaluate the chosen ownership and regulatory models, based on the four policy objectives established by House Bill 1700 (Act 124 of 2016). Figure 4 lists the state policy objectives and the evaluation criteria used to rank the different models.

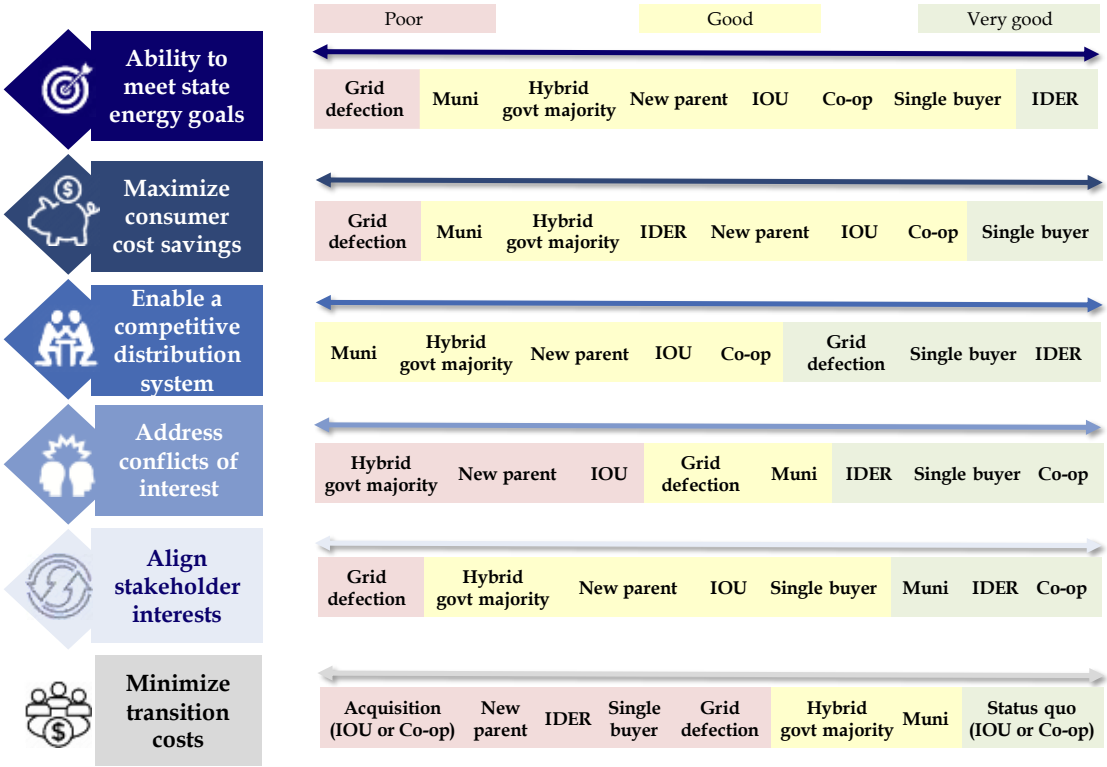
[4] DBEDT.UtilityBizModStudy@hawaii.gov

Figure 4. State policy objectives and evaluation criteria

State policy objectives	Evaluation criteria	Notes
1) Achieve State energy goals	• Ability to meet State energy goals	Assess each model's ability to meet the State energy goals
2) Maximize consumer cost savings	• Maximize consumer cost savings • Assess transition costs	Consumer costs include both ongoing costs under the model, plus any cost associated with transitioning
3) Enable a competitive distribution system	• Ability to support a competitive distribution system	Assess each model's ability to allow for competition at the distribution level
4) Eliminate or reduce conflicts of interest	• Address conflicts of interest • Align stakeholder interests	Remove the potential for conflicts of interest in utility investments, and align incentives for all stakeholders

The Project Team then performed a qualitative evaluation of the eight ownership models described previously with respect to each of the six ranking criteria, assessing how each potential ownership model would help achieve the state policy objectives absent any changes to the regulatory model. The high-level results of this assessment are presented in Figure 5 below and discussed in Section 4.4. The results were used to identify a subset of ownership models for detailed analysis, as further discussed in the next section.

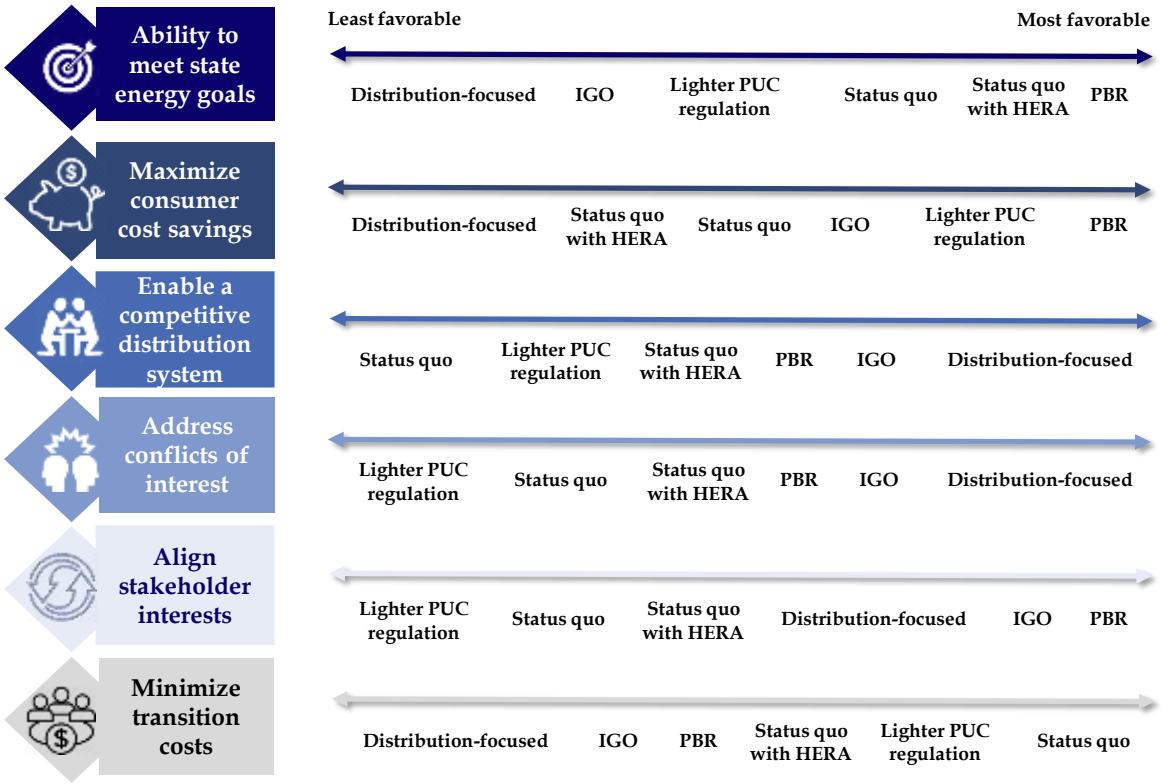
Figure 5. Evaluation of ownership models relative to the ranking criteria



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Similarly, the Project Team performed a qualitative evaluation of the six regulatory models described previously with respect to each of the six ranking criteria, again assessing how each potential regulatory model would help achieve the state policy objectives. The high-level results of this assessment are presented in Figure 6 and discussed in detail in Section 5.5. Once again, the results of the analysis were used to identify a subset of regulatory models for detailed analysis, as further discussed in the next section.

Figure 6. Evaluation of regulatory models relative to the ranking criteria



1.2 Ownership and regulatory models selected for further study

Based on the high-level analyses, comments received from the community dialogues, one-on-one meetings, and the qualitative evaluation, four ownership models were selected for further analyses in all counties:

- Investor-Owned Utility ("IOU");
- Cooperative ("co-op");
- Single Buyer ("SB") (inside the utility); and
- Single Buyer ("SB") (outside the utility).

For Hawaii, Honolulu, and Maui counties, the Project Team selected four regulatory models for additional review, namely:

- Status Quo;
- Outcomes-Based Performance-Based Regulation ("PBR");

- Conventional PBR; and
- Hybrid.

For Kauai County, the four regulatory models selected for additional review were:

- Status Quo;
- Hawaii Electricity Reliability Administrator ("HERA");
- Independent Grid Operator ("IGO"); and
- Lighter Public Utilities Commission ("PUC") Regulation.

Figure 7 provides a brief description of each of the selected ownership and regulatory models.

Figure 7. Selected utility ownership and regulatory models for further review

	Selected models for further review	
Ownership Models	**Status Quo**	HECO Companies would continue to operate as an IOU while KIUC would operate as a co-op
	Co-op	HECO Companies would move to a co-op model where its members own the utility
	Single Buyer (within the utility)	HECO Companies would create a Single Buyer unit within the utility, ring-fenced from the other business entities of the HECO Companies
	Single Buyer (outside the utility)	A Single Buyer entity would be created as a stand-alone entity outside of the utility, governed by an independent entity not affiliated with the utility
Regulatory Models	**Status Quo (COS with some PBR mechanisms for the HECO Companies)**	HECO Companies would continue to be regulated under a cost of service approach with some PBR mechanisms KIUC would continue to be under the PUC's purview
	Outcomes-based PBR	PBR focused on outcomes related to enhancing customer experience, improving utility performance, achieving public policy goals, and attaining healthy financial performance
	Conventional PBR + Light HERA	Conventional PBR enhances the current PBR mechanisms and would use an indexation formula to determine the revenue requirements of the utilities.
	Hybrid	Under the Hybrid model, the Outcomes-based PBR would be implemented first, followed by an IGO, and DSPP. Under the IGO, an independent entity would be responsible for planning and operations, including the dispatch of both the transmission and distribution system. Lastly, utilities provide distributed system platform ("DSP") services to enable third-party DER providers to create value for both customers and the system
	Lighter PUC regulation	Co-ops would be exempted from most of the PUC's regulations established based on an IOU structure; PUC investigation could be opened following certain events

The Project Team then conducted a more in-depth review of the selected models. The additional review involved determining the steps, timeline, and legal changes needed to transition to the selected models; the impact of the transition on the revenue requirements of the utilities, relative staffing needs of the Commission, ability to help Distributed Energy Resource ("DER") integration, and ultimately, average costs to the customers; and understanding the funding mechanisms to transition or establish the models. Figure 8 summarizes the timeline, legal changes, and costs required to implement alternative models in moving to another model and Sections 4.10 to 4.12 (for ownership models) and Sections 5.12 to 5.14 provide a more detailed discussion of these analyses.

Figure 8. Estimated timeline, legal/regulatory changes, and costs required to move to another model

	Models	Estimated time to move to a new model	Legal/regulatory changes required to move to a new model	Cost requirements of change in model
Ownership Models	**Status Quo (IOU)***	None	No	• None
	Co-op	24-36 months	No – burden of proof rests on the co-op to demonstrate that it can meet the laws and regulations already in place	• Acquisition costs • Regulatory costs
	Single Buyer (within the utility)	36-48 months	Yes – might require a PUC proceeding	• Set up costs for the Single Buyer (e.g., ring-fencing mechanisms) • Operating costs for the Single Buyer
	Single Buyer (outside the utility)	~48 months	Yes – legislative action is required to establish a new entity to undertake former utility planning and procurement responsibilities	• Set up costs for the Single Buyer • Operating costs for the Single Buyer
Regulatory Models	**Status Quo (COS with some PBR mechanisms)**	~21 months for PBR	No	• Regulatory costs to the utilities and the Commission
	Outcomes-based PBR	~21 months	No - no legal changes needed because PBR falls under existing PUC authority	• Regulatory costs to the utilities and the Commission
	Conventional PBR + Light HERA	39-45 months	No - there is existing regulation already for both PBR and HERA	• Regulatory costs to the utilities and the Commission • Costs to operate the Light HERA
	Hybrid	81-85 months	Yes - PUC proceeding is required and legislative changes may be required to authorize a DSPP	• Costs to set up the IGO and HERA • Operating costs of IGO and DSPP • Regulatory costs (PBR)
	Lighter PUC regulation	<12 months	Yes - the State Legislature would need to either customize any statutory laws for electric co-ops or authorize the PUC to do so	• Limited regulatory costs for the transition

Based on the analyses, a regulatory or legal change is needed in most of these models, especially those that require the creation of an independent entity (SB, IGO, and DSPP). Transitioning to a

different model also creates additional costs, including acquisition costs,[5] regulatory costs, and set up costs.

The Project Team's analysis results show that a change in ownership model does not necessarily address the first priority or concern of stakeholders, also a core objective of House Bill 1700 (Act 124), which is to lower electricity rates. In fact, a change in ownership model, either to the co-op model or the IOU model in the case of KIUC, would likely raise the average electricity rates relative to Status Quo in all the counties, except in Maui County. A key takeaway is that transitioning ownership models has a cost, regardless of the model, notably because of the cost for the new owner in acquiring assets from the incumbent utility. Figure 9 summarizes the impact on rates from the various ownership and regulatory models in all the counties.

Figure 9. Summary of impact on average residential rates by county and model (2018 – 2045)

	Honolulu County	Hawaii County	Maui County	Kauai County
Alternative ownership model				
Move to a co-op model	↑ 5.3%	↑ 8.2%	↓ -1.8%	
Move to a Single Buyer within the utility model	↓ -0.7%	↑ 0.3%	↓ -1.3%	↑ 1.0%
Move to a Single Buyer outside the utility model	↓ -0.8%	↑ 0.3%	↓ -1.3%	↑ 1.0%
Move to an IOU model				↑ 6.7%
Alternative regulatory model				
Implement an Outcomes-based PBR model	↓ -2.1%	↓ -4.8%	↓ -2.2%	
Implement a Conventional PBR + Light HERA model	↓ -2.2%	↓ -4.4%	↓ -1.9%	
Implement Hybrid Model	↓ -0.4%	↓ -9.2%	↓ -2.2%	
Move to a Lighter PUC Regulation				↓ -0.8%
Establish a HERA model				0.0%
Establish an IGO model				↓ -0.2%

More specifically, for Honolulu and Hawaii counties, a change to the co-op model is projected to increase average rates between 2018 and 2045 by an average of 5% and 8% per year, respectively. This increase is driven primarily by the cost of the purchase of assets of the incumbent utility, assumed to be undertaken through 100% debt financing. As a result, the co-op model is expected to lead to significantly higher debt burden, which would include interest payments. The higher costs of servicing the debt incurred for acquisition coupled with the additional financing needed for planned capital expenditure are expected to outweigh some of the cost reductions from the move to a co-op model in Honolulu and Hawaii counties. On the other hand, for Maui County, a move to the co-op model is projected to decrease electricity rates by an average of 2% per year. The projected decline in electricity rates would be primarily caused by the lower expected

[5] Related to a change in ownership model where a new owner would need to purchase the incumbent owner's assets, such as when transitioning from an IOU to a co-op or vice-versa.

acquisition cost relative to the number of customers and forecasted sales, especially compared to Hawaii County.

For Kauai County, a change to the IOU model is projected to increase average rates between 2018 and 2045 by an average of almost 7% per year. Notably, a transition to an IOU model would increase the financing costs since IOUs have a higher weighted average cost of capital than co-ops based on their cost of debt and their cost of equity.

On the other hand, the analyses showed that regulatory changes are likely to have a more significant impact when it comes to reducing electricity rates. For example, the electricity rates are projected to decrease between an average of 0.5% and 9% per year as a result of regulatory changes, depending on the county (Figure 9). This is primarily driven by strong incentives, such as those typically provided in PBR. PBR models can be designed to incentivize the utility to lower different categories of costs through targeted measures. In addition, it was observed that the benefits of the move to any of the PBR options generally outweigh the costs.

For Kauai County, the Lighter PUC Regulation model results in lowest rates (average of 0.8% per year) because of lower anticipated regulatory costs for the utility. In contrast, the HERA model would increase the electricity rates slightly because it adds incremental expenses without direct financial benefits to the ratepayers. The benefits of HERA are more oriented towards the quality and reliability of service than cost reductions. Meanwhile, the Project Team expected some efficiencies in the IGO model, especially from the transfer of grid operations to a specialized independent entity that manages both utility-scale and distribution level supply resources. However, the overhead costs associated with setting up and operating an additional entity do partially offset cost savings associated with power procurement, especially in a smaller system such as operated by the Kauai Island Utility Cooperative ("KIUC").

The potential ownership and regulatory models were also evaluated in terms of their impact on DERs, risks to the utility, staffing requirements for the Commission, and potential stranded costs. While these factors informed the selection of the highest rated ownership and regulatory models, the financial impacts discussed above must also be taken into account.

1.3 Additional analyses

The Project Team also performed a high-level qualitative assessment of whether the benefits of ownership and regulatory model changes can be achieved through changes in rate design (Section 7.1). The Project Team evaluated a range of alternative rate designs including tiered rates (inclining and declining block rates), higher fixed charges, and time-varying rates (Time-of-Use ("TOU") rates, Real-Time Pricing ("RTP"), and Critical Peak Pricing ("CPP")). Based on a high-level qualitative evaluation of these alternative rate designs, the Project Team concluded that rate design changes can be effective complementary mechanisms to ownership and regulatory changes and could help achieve some of Hawaii's state energy goals such as increasing the adoption of DERs and other consumer side resources, lowering peak demand, and encouraging energy conservation. At the same time, rate design is inherently interlinked with ownership and regulatory models and care must be taken to ensure that changes to rate design are consistent with overall policy goals in light of the prevailing ownership and regulatory model.

Finally, the Project Team evaluated the management of the State's electricity sector with each county operating independently as compared to a multi-county model approach (Section 7.2). The single-county vs. the multi-county models were analyzed from the perspective of the utilities' management and operations, particularly with regards to how the utilities operate the electricity system from sourcing supply to dispatching resources. The analysis showed that the multi-county model is better positioned to address the State's priorities. It received a better rating in three out of five criteria, namely, the ability to meet state energy goals, maximize consumer cost savings, and enable a competitive distribution system. In contrast, the single-county model works better in addressing two of the five criteria, namely, conflicts of interest and aligning stakeholder interests. The sixth criteria, transition costs, was not within the scope of the study for assessing single versus multi-county models as it would require a detailed analysis of the costs and policy implications of interconnecting two or more of the island grids, which is outside the scope of this study.

1.4 Key takeaways

Based on the Project Team's analyses, alternative regulatory models have a greater likelihood of helping to achieve the core policy objectives of House Bill 1700 (Act 124) relative to changes in utility ownership. This conclusion is further supported given that shortcomings of the current ownership models identified in the evaluation can be offset by changes to the regulatory model. For example, the legislature passed the Ratepayer Protection Act (SB 2939) of 2018 to address capital investment bias for investor-owned utilities under the existing regulatory regime.

The Project Team incorporated assumptions for its analyses based on publicly available data and existing studies on future developments of the State's electric infrastructure. While the actual costs for a specific implementation of alternative models may vary from the chosen assumptions, the Project Team's approach was selected to leverage data and studies that have been reviewed and approved by the Public Utilities Commission ("PUC"). This report and the supporting analyses provide enough detail to gauge the impact of changes in assumptions on the assessments contained within.

The Project Team concluded that a preferred outcome for the evolution of Hawaii State's utility business model could include a PBR framework[6] and possibly integrate alternative regulatory structures complementary to PBR. These alternative regulatory structures could be incorporated following the initial implementation of a PBR framework in Hawaii State, with decisions on whether, and how, to incorporate them being informed by developments in other jurisdictions which are currently exploring those concepts.

This Report is a summary of the analyses conducted for more than 40 underlying tasks and reports, which contain more background and additional details. These underlying reports are available on the Hawaii State Energy Office website.[7]

[6] Subject of ongoing Docket No. 2018-0088 at the PUC and a statutory requirement as mandated by the Ratepayer Protection Act (SB 2939) of 2018

[7] https://energy.hawaii.gov/

2 About the Study

DBEDT, through House Bill 1700 (Act 124 of 2016), was directed by the legislature to conduct a "study to evaluate the alternative utility and regulatory models,"[8] (the "Study") and "the ability of each model to:

1. achieve state energy goals;
2. maximize customer cost savings;
3. enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer needs; and
4. eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation."[9,10]

Through a competitive procurement process,[11] LEI was awarded a contract to conduct the Study in March 2017. LEI undertook this Study in collaboration with Meister Consultants Group (A Cadmus Company) and Yamamoto Caliboso LLLC (collectively, the "Project Team"). The project kick-off was held in May 2017.

2.1 Process

The Study was divided into five major phases, as illustrated in Figure 10. The first phase of the Study involved the examination of existing electricity assets owned by utilities (e.g., generation, transmission, and distribution facilities) and how needs might evolve based on the utilities' plans.

Figure 10. Key Phases in the Study



The second phase focused on the review of potential utility ownership models. Several possible models for Hawaii were considered such as traditional utility-centric models [for example, IOU, co-op, municipal ("muni")], and hybrid ownership (where the State government has a majority share). Furthermore, given that technological change in the electricity sector is enabling new potential ownership arrangements, Single Buyer ("SB"), Integrated Distributed Energy Resource

[8] HB1700, Act 124. Task 7.

[9] Ibid.

[10] These are considered the goals of the legislation that directed this Study.

[11] Hawaii No. RFP-17-020-SID dated September 30, 2016; Addendum No. 1 dated October 20, 2016; Addendum No. 2 dated October 24, 2016.

("IDER") operator, and grid defection models were also included in the Study. These models are discussed in detail in Task 1.1.1. (*Introduction of ownership models*).

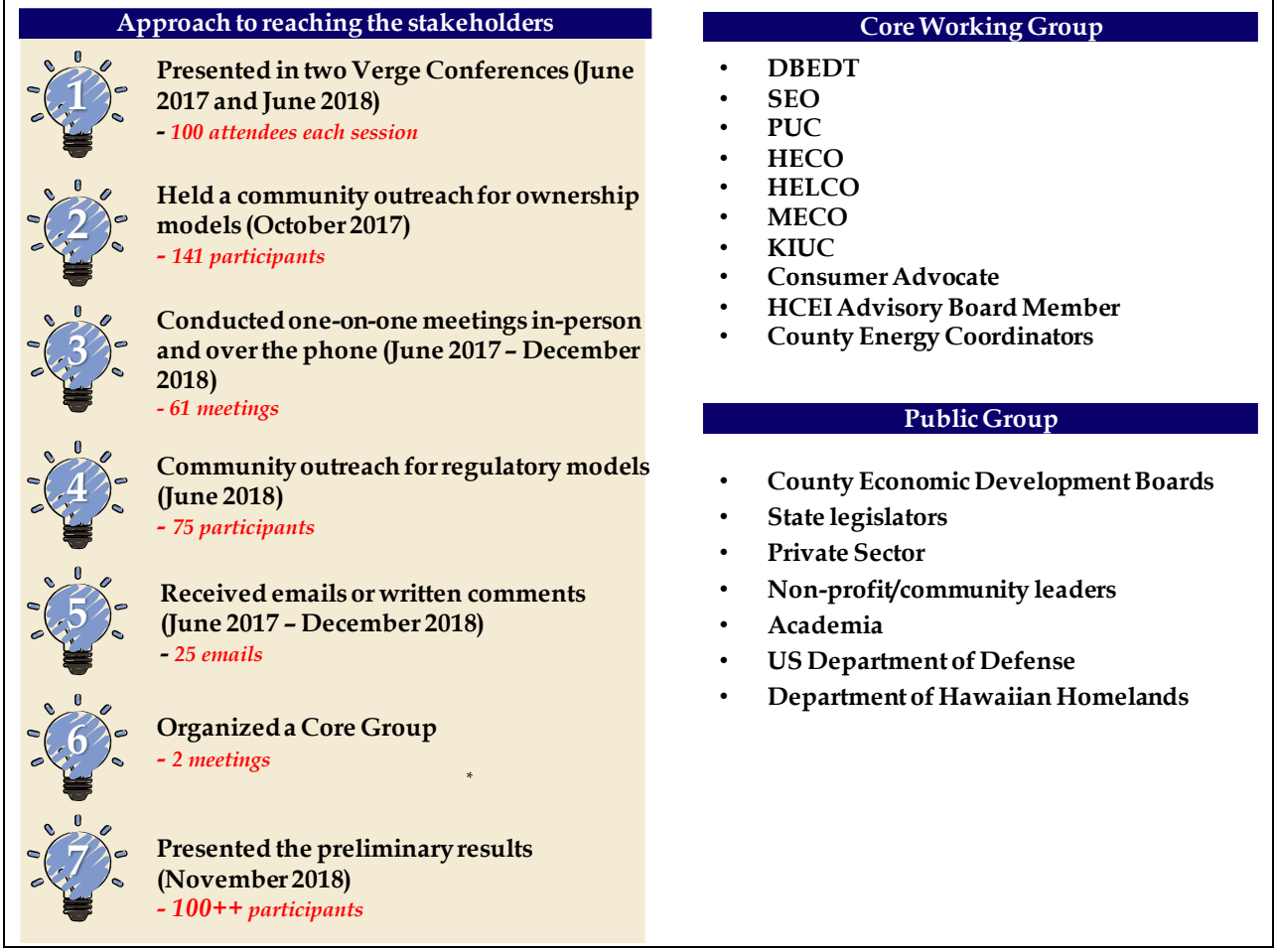
The Project Team then conducted high-level assessments on eight (8) potential utility ownership models. These evaluations considered each model's advantages and disadvantages, similarities and differences, and how the transition to another model would impact each segment of the electricity value chain. For example, the analysis looked into whether the move would require divestment of generation or wires assets. Moreover, the utility ownership models were evaluated quantitatively to see how they relate to the key policy objectives of House Bill 1700 (Act 124 of 2016), which include achievement of state energy goals, maximization of consumer cost savings, enabling a competitive distribution system, and elimination or reduction of conflicts of interest. Also, the Project Team performed a high-level assessment of the financial, technical, and legal feasibility of transitioning to each model. Lastly, the potential for stranded costs resulting from the change in ownership was assessed. Stranded costs represent the costs that a utility was allowed to recover through regulated rates but whose recovery may be impeded or prevented as a jurisdiction transitions from a regulated regime to a competitive, deregulated environment.

Furthermore, the Study entailed extensive community engagement on all the islands studied to solicit the views of stakeholders periodically throughout the project. A total of seven community outreach events on utility ownership models were conducted in October 2017 on Hawaii, Maui, Lanai, Molokai, Oahu, and Kauai islands. Moreover, the Project Team presented an overview of the Study during the VERGE Conferences in Honolulu on June 20, 2017, and June 12, 2018, where a total of approximately 100 participants attended each session. In addition to the community outreach activities, about 60 one-on-one meetings with various stakeholders were conducted to solicit their input on the different models. During the Study, the Project Team met with utilities, government, non-profit, and other stakeholders from across the State. Figure 11 lists the approaches conducted to reaching the stakeholders, and Section 8 lists the parties that were met throughout the process.

Using a set of criteria tied to the policy objectives of House Bill 1700 (Act 124 of 2016), the Project Team ranked the models and undertook further analyses on the top three most beneficial models in addition to the status quo (IOU in all counties except Kauai where the utility is a co-op). These selected models include IOU, co-op, SB within the utility, and SB outside of the utility for the ownership models. The analyses performed included the identification of steps, timeline, and costs required to change from the current model to an alternative model as well as legal changes necessary to implement the proposed model. The additional review also involved assessing how each model could impact the PUC and the Division of Consumer Affairs ("DCA") staffing, DER integration, utilities' revenue requirements, and average rates paid by consumers. To determine the projected revenue requirements and electricity rates through 2045, the Project Team created a revenue requirement model for each of the four models and four counties, resulting in a total of 16 revenue requirement models. Furthermore, the Project Team identified the funding mechanisms to support the transition and operations of these different ownership models. Task 1.2.5 (*Ranking process and rationale for the recommendation of three feasible utility ownership models*) discusses the criteria used as well as the ranking while Tasks 1.3 to 1.6 provide the results of the additional review.

Phase 3, which involved the review of regulatory models, followed the same process as in Phase 2. Several possible models for Hawaii were considered such as the Status Quo but with increased oversight through the establishment of the HERA model, the establishment of an independent grid operator ("IGO"), a distribution-focused model, PBR, or lighter PUC regulation for electric co-ops.

Figure 11. Approach for reaching out to the stakeholders



Task 2.1.1 (*Ranking process and rationale for the recommendation of three feasible utility ownership models*) provides a more detailed discussion of the different regulatory models.

The Project Team conducted the same high-level analyses on the selected regulatory models as those that were performed on the various ownership models. The project team also presented these regulatory models over eight community outreach events conducted in June 2018, soliciting input and feedback from stakeholders. A total of 216 persons participated in these community outreach activities.

Using the criteria developed to address the policy objectives set by House Bill 1700 (Act 124 of 2016), the Project Team ranked the regulatory models and conducted a further review of those that rated highly. These shortlisted regulatory models for Hawaii, Maui and Oahu counties

include the Outcomes-based PBR, Conventional PBR (with Light HERA), and a Hybrid model combining the Outcomes-based PBR, IGO, and distribution-focused models. In the case of Kauai County, the Project Team selected the HERA model, IGO, and lighter PUC regulation.

The Project Team then performed in-depth analyses on these high-ranked regulatory models to determine the impact of the regulatory change on the utilities' revenue requirements, cash flows, and average electricity rates as well as its effects on DER deployment and staffing needs of the PUC. Similar to the ownership model assessment, the Project Team created a revenue requirements model for each regulatory structure option for each county to derive the revenue requirements and electricity rates through 2045. A total of 12 revenue requirements models were prepared to evaluate the regulatory models. In addition, the Project Team identified the potential funding mechanisms to support the transition and operations of these regulatory models.

Under Phase 4, additional analyses were carried out which included: (i) a high-level assessment of whether the benefits of ownership and regulatory model changes could be achieved through changes to Hawaii's existing rate design; and (ii) the advantages and disadvantages of each county operating independently as compared to collectively as a part of a multi-county model.

The final report was drafted summarizing the results of the various analyses performed in all the phases. The Project Team also revisited the islands in November 2018 to present the preliminary results of the Study. Comments from the participants were solicited, reviewed, considered, and reflected in this Final Report.

2.2 Data sources

The Project Team's analytical work used data and information from relevant statutes, PUC Decisions, and Orders, as well as reports from the utilities themselves. The Project Team also collaborated extensively with the utilities, requesting specific data (if available) to supplement publicly available information. The following literature was reviewed to inform the analyses:

- Utility filings and PUC Orders under Hawaiian Electric Company's ("HECO") rate case (Docket No. 2016-0328), Hawaii Electric Light Company's ("HELCO") rate case (Docket No. 2015-0170), Maui Electric Company's ("MECO") rate case (Docket No. 2017-0150), and Kauai Island Utility Cooperative's ("KIUC") rate case (Docket No. 2009-0050);
- HECO Companies' projections for capital expenditures, resource plans, fuel prices, and load growth in the Power Supply Improvement Plan ("PSIP") report;
- HECO Companies' grid modernization strategy – Modernizing Hawaii's Grid for Our Customers ("Grid Modernization Report");
- KIUC Depreciation Study;
- KIUC 2017 Capital Improvements Program for Five Years;
- The utilities' Annual Financial Reports ("AFR") filed with the PUC;
- KIUC annual reports;
- KIUC Audited Financial Statements;
- DBEDT 2017 State of Hawaii Data Book; and

- DBEDT Economic Forecasts – Population and Economic Projections for the State of Hawaii to 2040.

The Project Team also reviewed external resources to inform assumptions on transitions to different ownership or regulatory models. This included reports and data from widely cited industry resources such as National Renewable Energy Laboratory, Lazard, and the Energy Information Agency, as well as regulatory filings for relevant models in jurisdictions such as Alberta, Ontario, Malaysia, New York, Texas, and the UK. A list of all the resources reviewed is in Section 11. This Final Report and the other reports completed for this Study include citations of and references to all sources consulted.

2.3 Reports included in the study

This final report is the culmination of 23 months of work (June 2017 to March 2019). The Project Team completed more than 40 tasks (as listed below), and all reports for these tasks are available on the Hawaii State Energy Office website.[12] This Final Report is essentially a summary of all these reports, so references to those individual reports, which contain more detailed analyses and documentation, are included.

1) Task 1.1.1 – Introduction of ownership models and asset identification
2) Task 1.1.2 – Maps for service areas of each county
3) Task 1.1.3 – Assessment of existing generation, transmission, and distribution infrastructure
4) Task 1.1.4 – High-level assessment of future needs for generation, transmission, and distribution infrastructure
5) Task 1.1.5 – High-level identification of system improvements planned for installation in the next five years and proposed improvements needed until 2045
6) Task 1.1.6 - Identification of estimated stranded costs for each ownership model
7) Task 1.2.1 - Comparison of ownership models and how they relate to the State's key factors
8) Task 1.2.2 - Empirical research and data that support the qualitative assessment of ownership models in Task 1.2.1
9) Task 1.2.3 - Summary and conclusions on the technical, financial, and legal feasibility of each ownership model
10) Task 1.2.4 – Outreach Plan and documentation of results from public outreach in each island served by an electric utility
11) Task 1.2.5 - Ranking process and rationale for the recommendation of three feasible utility ownership models

[12] https://energy.hawaii.gov/

12) Task 1.3.1 - Identification of various steps, timeline, and requirements (including costs and regulatory approvals) of the change from the current ownership model to new models

13) Task 1.3.2 - Identification of legal changes that are needed in implementing the proposed utility legal framework options

14) Task 1.3.3 - Identification of risk for each ownership model, analysis of each risk, and assessment of the overall risk profile for each ownership option

15) Task 1.3.4 - Assessment of how each ownership model impacts staffing of State agencies and stakeholders

16) Task 1.4.1 - Assessment of substantive estimate of book value for existing facilities that would need to be acquired to ensure the provision of electrical services in each county

17) Task 1.4.2 - Economic evaluation of ownership and operation of each ownership model

18) Task 1.4.3 - Assessment of management structure and staffing plan needs under each ownership model, including an assessment on the oversight management and staffing needs for Public Utilities Commission and Consumer Advocate

19) Task 1.5.1 - Estimated potential of each model to increase distributed energy resources, demand response programs, system security, reliability, resiliency, and RPS requirements through 2045

20) Task 1.5.2 - Annual load and customer projections until 2045

21) Task 1.6.1 - Overview of the differences in how revenue requirement is calculated under each ownership model

22) Task 1.6.2 - Analysis of how each ownership model would affect cash flows

23) Task 1.6.3 - Estimated revenue requirements under each ownership model until 2045

24) Task 1.6.4 - Matrix comparing system average retail rates for an average residential, commercial, and industrial customer under each ownership model up to 2045

25) Task 1.6.5 - Qualitative assessment of financing options for each ownership model

26) Task 2.1.1 - Summary comparison of Regulatory Models from Hawaii's perspective, including a graphical depiction of each regulatory model and comparison

27) Task 2.1.2 - Comparative review of regulatory models, including a high-level process assessment

28) Task 2.2.1 – High-level evaluation of the regulatory models relative to the State's goals

29) Task 2.2.2 - Assessment of current markets under each regulatory model, including a case study, analysis, and conclusions

30) Task 2.2.3 - High-level assessment of the technical, financial, and legal feasibility of each regulatory model

31) Task 2.2.4 - Summary analysis and conclusions related to estimating stranded costs for each regulatory model

32) Task 2.2.5 - Outreach Plan and documentation of results of public outreach in each island currently served by an electric utility

33) Task 2.2.6 - Identification of and recommendation for the three most beneficial regulatory models for further consideration

34) Task 2.3.1 - Identification of steps, costs, and projected timelines of the change from the current regulatory model to the recommended regulatory models

35) Task 2.3.2 - Analysis of Hawaii law and history to determine the regulatory and legislative changes needed to implement the recommended regulatory models

36) Task 2.3.3 - Identification and assessment of the impact of known or potential financial and operational risks to different stakeholders (ratepayers, utility shareholders, taxpayers) under each regulatory model

37) Task 2.3.4 - Assessment of how each regulatory model could impact state agencies and stakeholders such as the Public Utilities Commission and the Consumer Advocate (similar to analysis conducted in Task 1.3.4)

38) Task 2.4.1 - Estimated potential of each model to increase distributed energy resources, demand response, system security, reliability, resilience and meet Hawaii's RPS milestones up to 2045

39) Task 2.5.1 - Estimated annual revenue requirement of each of the remaining recommended regulatory models, including major costs by category; graphical representation comparing the three regulatory model outcomes

40) Task 2.5.2 - Assessment of system average retail rates for an average residential, commercial, and industrial customer in each regulatory model up to 2045

41) Task 2.5.3 - Analysis of how costs differ under each regulatory model as well as an explanation of the revenue requirement calculation under each model

42) Task 2.5.4 - Analysis of any issue that could impact the valuation of an electric utility in the regulatory model and identify key risks in utility valuations

43) Task 2.5.5 - Identification of funding mechanisms for each regulatory model

44) Task 3.1.1 - Assessing whether benefits of changes of ownership and/or regulatory model could be accomplished through changes in rate design

45) Task 3.1.2 - Assessing how changes in rate design compares to regulatory and ownership model changes considering overall market conditions

46) Task 3.1.3 - Assessing the pros and cons of managing Hawaii's electricity sector with each county operating independently as compared to a multi-county model

2.4 Caveats

While the list of utility ownership structures and regulatory models reviewed in this Study is not exhaustive, the Project Team believes it is representative of both existing and emerging alternatives. Moreover, as there can be wide variations within each model type, the Project Team described them in a way that encompasses the most common forms. Nevertheless, each can be further customized to meet the needs of the state of Hawaii or the individual Hawaiian Islands.

While the Project Team has taken all reasonable care to ensure that the analyses are complete, the electricity market in Hawaii is highly dynamic. Thus, certain recent developments may not be included in the analyses. For instance, some of the analyses conducted in this report were performed in 2017 and 2018 so those very recent developments related to PBR, such as the PUC Staff Proposal on the recommended regulatory outcomes (which was issued on February 7, 2019), are not reflected in this report.

Also, the analyses in this Study were not intended to be comprehensive, nor can they account for all circumstances in the future. There can be substantial variation between assumptions used and actual market outcomes. No results provided in the analyses should be taken as a promise or guarantee as to the occurrence of any future events. However, this report is intended to provide sufficient detail to inform the assessment of future events or changes in assumptions on the conclusions reached in the study.

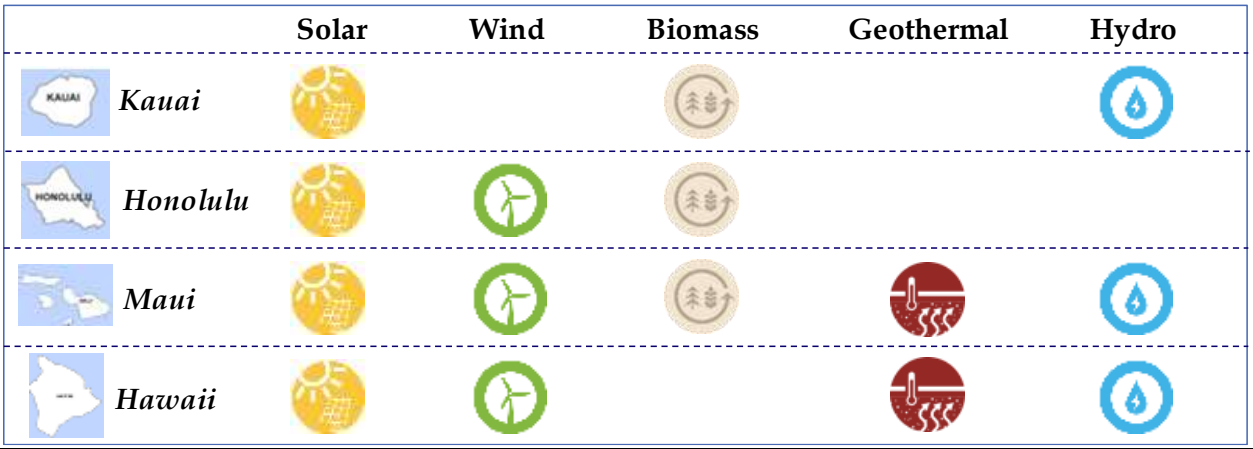
Lastly, it is important to keep the time horizon in mind when discussing each model. While the Project Team evaluated the different models relative to the Status Quo at the time this Study was conducted, the relative costs and benefits of each model may change over the nearly 30-year time horizon between the present and 2045.

3 Overview of Hawaii's electricity market

The Project Team considered the uniqueness of the State of Hawaii as well as each county in the analyses of the Study. Unlike states on the US mainland, Hawaii is comprised of islands and therefore relies heavily on imports, including oil, which tends to increase electricity prices as well as the cost of other imported consumer products. Each island's electric grid is independent, as there are no interconnections between islands. Furthermore, the state is vulnerable to various kinds of natural disasters, so resilient infrastructure is needed. It is also home to the largest concentration of US military bases in the country, so reliable electricity is essential.

Hawaii is the first state with a legislative goal of achieving 100% renewable energy. On June 8, 2015, the State passed Act 97 Session Laws of Hawaii 2015 which amended section 269-92 Hawaii Revised Statutes (proposed as House Bill 623) to increase its 2020 renewable portfolio standards ("RPS") target to 30%, maintain the 2030 RPS target at 40%, add a 2040 RPS target of 70%, and add a 2045 RPS target of 100%. The law applies to all electric utilities that sell electricity for consumption in the state and sets interim targets for net electricity sales.[13]

Figure 12. Renewable resources in each county



Each island is different and has its distinctive characteristics, resources, and challenges. For instance, the City and County of Honolulu represents the state's load center, with an annual demand that is more than twice the aggregated demand in the other three counties in 2017.[14] The County of Hawaii has a socio-economic disadvantage compared to the other counties because its income per capita was the lowest among the four counties (almost 30% lower than that of the City and County of Honolulu).[15] The County of Maui includes the three islands of Maui, Molokai, and Lanai, while the other three counties all consist of a single island that is served by an electric

[13] Affiliated electric utilities can aggregate their renewable portfolio to achieve the targets.

[14] DBEDT. *2017 State of Hawaii Data Book: Task 17 – Energy and Science*. Page 17.10.

[15] DBEDT. *2017 State of Hawaii Data Book: Task 13 – Income, Expenditures, and Wealth*. Page 13.12.

utility company. Kauai is the only county that is served by a co-op electric utility while the other three counties are served by an IOU.

Furthermore, the available renewable resources vary by county, so the renewable energy development potential in each is also different, as shown in Figure 12. For instance, it would be challenging to develop geothermal or hydro stations in the City and County of Honolulu while these would be more technically viable in Hawaii County (though they may or may not be politically acceptable).

3.1 Market overview

Hawaiian Electric Industries ("HEI") and KIUC are the two primary electric utilities that service the power needs of the state. HEI and its subsidiaries, including HECO, MECO, and HELCO, serve the majority of the state's electric utility customers, more specifically in the counties of Hawaii, Maui, and the City and County of Honolulu. For the purpose of this report, the subsidiaries HECO, HELCO, and MECO will be referred to as the HECO Companies, which owns these subsidiaries. KIUC serves the island of Kauai. [16]

These utilities are vertically integrated utilities, which means that their organizational structure encompasses generation, transmission, and distribution. The same entities, without significant internal separation, are also responsible for system planning, maintaining reliability, coordinating dispatch and grid operations, and ensuring that there is an adequate supply of energy, whether by providing energy and capacity itself or by contracting supply from independent power producers ("IPPs").

The total installed capacity in the state is 3,427 MW (as of August 2017). The City and County of Honolulu has the highest share of installed capacity (68% of the State's installed capacity), followed by Maui, Hawaii, and Kauai Counties respectively. For counties served by the HECO Companies, renewable generation ranged between 11% (City and County of Honolulu) and 41% (Hawaii County) of the total generation in 2017.[17] On Kauai, renewable generation represented 43% of total generation in 2017.[18]

The state's heavy dependence on oil renders it the most petroleum-dependent state in the country.[19] Although Honolulu features the largest installed solar PV capacity when including distributed solar resources, Kauai boasts the highest percentage of solar PV capacity relative to its total installed generation capacity. Honolulu is the only county that has a coal-fired plant while Hawaii County is the only county that has geothermal generation, though the geothermal plant is currently not operational due to a volcanic eruption in 2018.

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[16] Hawaii State Energy Office. *Hawaii Energy Facts & Figures*. Honolulu: May 2017.

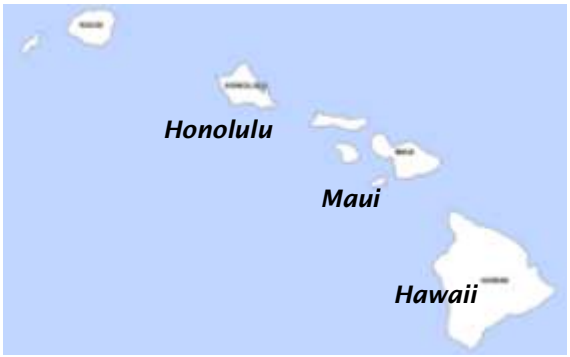
[17] <https://www.hawaiianelectric.com/clean-energy-hawaii/clean-energy-facts/about-our-fuel-mix>

[18] <http://website.kiuc.coop/renewables>

[19] EIA. *State Profile and Energy Estimates – Hawaii*. <https://www.eia.gov/state/analysis.php?sid=HI>

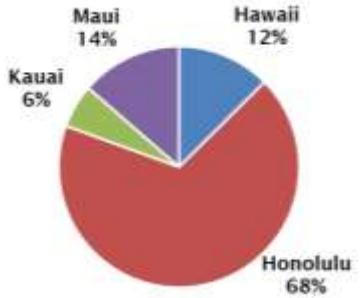
In terms of generation resource ownership, the HECO Companies dominate the generation sector, owning about 50% of the installed capacity in the State. They are the largest generation companies in Honolulu, Maui, and Hawaii counties, while KIUC is the dominant generation owner in Kauai County. There are also several IPPs in each county such as AES Corp, Tesla, Terraform Power, and Ormat Technologies, to name a few.

Figure 13. Snapshot of the Hawaii electricity market

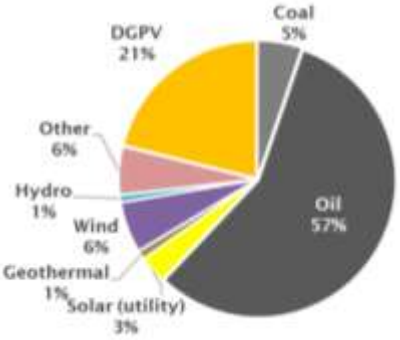


Key facts	
Installed capacity (as of August 2017)	3,427 MW
Peak demand (2017)	1,693 MW
Load growth (2012-2017)	-3.1%
Transmission lines	1,868 miles
Population (2017)	1.43 million
GDP growth (nominal, average annual growth, 2012-2017)	3.9%

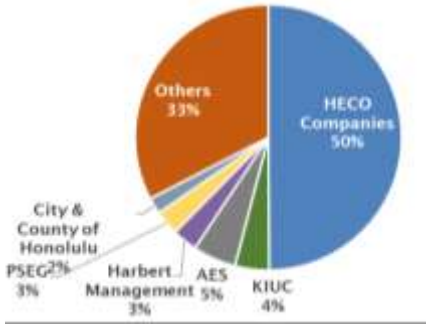
Installed capacity by county



Installed capacity by fuel type



Installed capacity by owners



Sources: HECO Companies website; KIUC website; HECO Companies' Power Supply Improvement Plans; 2017 State of Hawaii Data Book; HSEO Facts and Figures June 2018.

The electrical grids on the different islands are not interconnected to each other. The total length of transmission lines in the State of Hawaii is approximately 1,868 miles, with Hawaii County representing the largest share at about 33% of the total.[20] The transmission and distribution lines across all the four counties operate at voltages ranging from 13.8 kV – 138 kV,[21] and the operating capacity of substations ranges from 25 MVA to 320 MVA.

[20] The reported length of transmission lines is sourced from FERC Form 1 filings as of December 31, 2016.

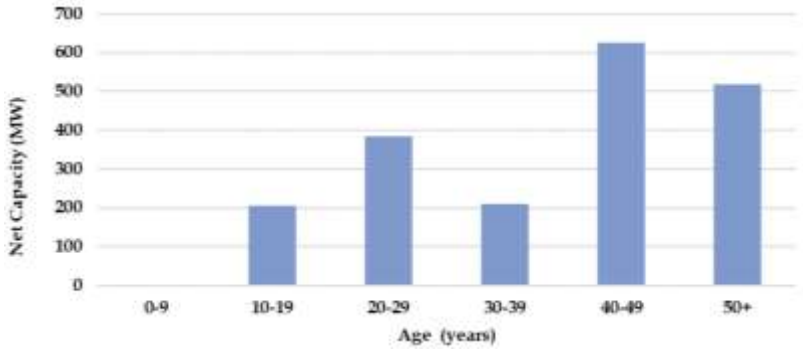
[21] Voltages of transmission lines usually vary from 69 kV to 765 kV. Source: NERC. *Glossary of Terms Used in NERC Reliability Standards*. Updated January 31, 2018.

Task 1.1.3 *(Assessment of existing generation, transmission, and distribution infrastructure in each county)* provides a more detailed discussion on the current generation, transmission, and distribution assets in the State.

Based on the review of the existing thermal generation assets in the State using documentation provided by KIUC and the HECO companies, the majority of these generation plants are old and about to reach the end of their useful life. More specifically, almost a third of the oil-fired generation capacity is between 40 to 49 years old, and more than a quarter is 50 years or older. The average age of the 1,946 MW of oil-fired generation units in Hawaii is 39.5 years old.

Almost 60% of these oil-fired plants are above the average age of retirements for oil-fired plants. Based on a sample of 148 retired plant units in the US, the average life of oil-fired plants is 39.7 years (ranging from 28 to 48 years old), depending on the technology.[22] More than 50% of the oil-fired plants in the State employ steam turbines while a quarter is combined cycle plants. The rest use either combustion gas turbines or internal combustion engines. Figure 14 shows a breakdown of the age of thermal plants in the State.

Figure 14. Age of oil-fired plants in the State



Source: HECO PSIP; KIUC website

Likewise, many of the HECO Companies' transmission and distribution ("T&D") assets are approaching the end of their useful life and need to be upgraded or replaced.[23] According to the HECO Companies, much of the installed T&D infrastructure is between 30 and 60 years old.[24] As the HECO Companies noted in the Grid Modernization Report, T&D infrastructure deteriorates due to many natural or human factors. The HECO Companies have an ongoing infrastructure replacement program to maintain the reliability of the grid to comply with the transmission reliability and security compliance standards and to avoid catastrophic events. The replacement of aging infrastructure costs more than the original installation (in real dollar terms) because of

[22] Energy Velocity database.

[23] HECO Companies. *Modernizing Hawaii's Grid for Our Customers*. August 2017 Draft Report. Page 53.

[24] HECO Companies. *Modernizing Hawaii's Grid for Our Customers*. August 2017 Draft Report. Pages 54-55.

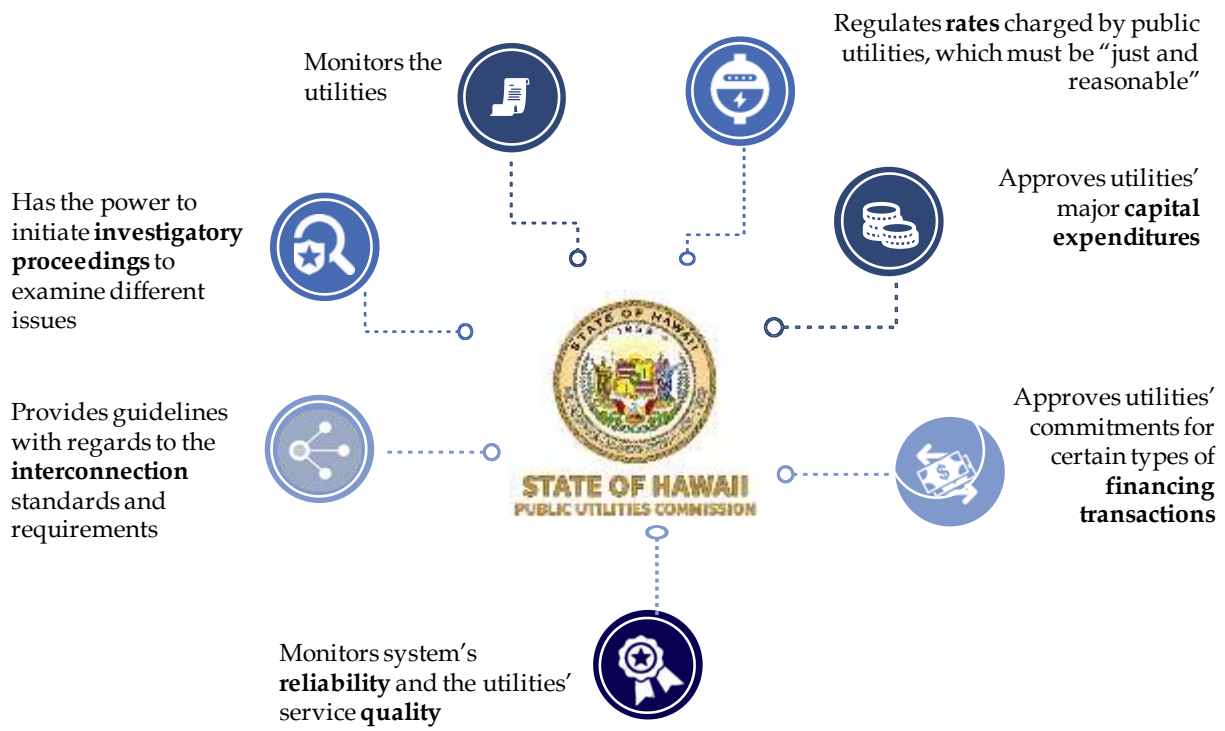
London Economics International LLC
717 Atlantic Avenue, Suite 1A
Boston, MA 02111
www.londoneconomics.com

the increased scope and complexity of replacement projects.[25] The Project Team noted HECO Companies' plans in the PSIP and the Grid Modernization Report and incorporated them in the revenue requirements model.

3.2 Institutional arrangements

The Hawaii electricity market has three main institutional public entities, namely, the State Legislature, PUC, and Hawaii State Energy Office ("HSEO"). The HECO Companies and KIUC are regulated by the PUC, whose primary mandated power and functions are shown in Figure 15.

Figure 15. PUC's mandated power and functions



Source: HRS § 269-16, HRS § 269-19, HRS §§ 269-27.5 and -27.6, HRS §§ 269-143(a), HRS § 269-6. HRS §§ 269-17 through -18, and HRS § 269-7

The PUC in Hawaii, as in other jurisdictions, exercises broad regulatory powers by utilizing its rule-making authority[26] to adopt, implement, and enforce rules and regulations that apply to electric utilities. The PUC has quasi-judicial authority in docket or case proceedings involving

[25] Ibid.

[26] *See* HRS § 269-6(a).

public utilities.[27] These proceedings are undertaken in administrative rule-making processes[28] or formal docket processes.[29] PUC is primarily mandated to "protect the public interest by overseeing and regulating public utilities to ensure that they provide reliable service at just and reasonable rates."[30]

The Hawaii State Legislature, co-equal to the executive and judicial branches of Hawaii's state government, is responsible for creating laws. The House Committee on Energy and Environmental Protection focuses on programs relating to energy resources and the development of renewable and alternative energy resources, energy conservation, environmental quality control and protection, and environmental health and other pertinent matters referred to it by the House.[31] Likewise, the Senate Committee Energy, Economic Development, and Tourism focuses on programs relating to energy resources, including the development of alternative energy resources.[32] Moreover, the Senate Committee on Commerce, Consumer Protection, and Health oversees regulations relating to public utilities and other regulated business[33] while the House Committee on Consumer Protection oversees programs relating to consumer protection and regulation of utilities.[34]

Task 2.1.2 *(Current regulatory model)* provides a more detailed discussion of the key institutional arrangements in the State.

3.3 Ratemaking process

The ratemaking process generally begins when a utility files notice of its intent to file for a general rate adjustment at least two months prior to submitting a rate application.[35] Typically, utilities request rate adjustments when costs have increased, or significant investments have been or are being made, and revenues collected no longer generate a reasonable rate of return. The difference must be sufficient in magnitude to justify the time and expense of applying for a rate increase. A

[27] *See* HRS §§ 269-6, -7, and HRS Chapter 269 generally.

[28] *See* HRS § 269-6(a); HAR §§ 6-61-146 to -155.

[29] *See* HRS Chapter 269, HAR Title 6 Chapter 61-1.

[30] *Introduction*. Available at http://puc.hawaii.gov/about/introduction/ (last visited April 9, 2018).

[31] *House Committee on Energy & Environmental Protection*. Hawaii State Legislature Website, Available at https://www.capitol.hawaii.gov/committeepage.aspx?comm=EEP (last accessed April 19, 2018).

[32] *Senate Committee on Energy, Economic Development, and Tourism,* Hawaii State Legislature Website, Available at https://www.capitol.hawaii.gov/committeepage.aspx?comm=TRE&year=2018 (last accessed May 14, 2018).

[34] *House Committee on Consumer Protection & Commerce*, Hawaii State Legislature Website, Available at https://www.capitol.hawaii.gov/committeepage.aspx?comm=CPC&year=2018 (last accessed May 14, 2018).

[35] HAR § 6-61-85(a).

rate case can also be initiated as required by the PUC. Each of the HECO Companies is required to file a rate case every three years,[36] while KIUC has not filed a rate case since 2010.[37]

The application describing the proposed change in rates is then submitted to the PUC along with written direct testimony justifying the request as well as supporting exhibits and work papers.[38] The Commission must determine whether the application is complete under HRS Chapter 269 as the deadline for the Commission to complete its deliberations and issue its decision begins only after a completed application is filed and served on the Consumer Advocate.[39] The Consumer Advocate has 21 days to object to the sufficiency of the application.[40] Accordingly, the Consumer Advocate will typically file a statement of position regarding the completeness of the application while the Commission will issue an order establishing the date the completed application was filed.[41]

As required by statute, the PUC holds a public hearing for each rate case.[42] Interested persons can file motions seeking to intervene or participate in the docket, which must be filed no later than ten (10) days after the last public hearing.[43] The PUC, the Consumer Advocate, and any admitted intervenors or participants may submit information requests to build the record in the proceeding, as may be allowed and subject to any condition and limitation that may be established by the PUC.[44] Typically, the utility, Consumer Advocate, and any parties granted full intervenor status may negotiate and file a stipulation or partial stipulation for the Commission to

[36] *See* Docket No. 2008-0274, Final Decision and Order, issued Aug. 31, 2010, at 129 ("So that the commission and the Consumer Advocate have a regular opportunity to evaluate decoupling and re-calibrate RAM inputs using commission-approved values, the HECO Companies shall file staggered rate cases every three years.").

[37] *See* Docket No. 2009-0050, Order Closing the Docket, issued Oct. 12, 2010, at 1-2.

[38] *See* HAR § 6-61-87 (applies to utilities with Annual Gross Operating Revenues of $2,000,000 or more).

[39] HRS § 269-16(d); HAR § 6-61-86, -87.

[40] HRS § 269-16(d).

[41] *See, e.g.*, Docket No. 2016-0328, Division of Consumer Advocacy's Statement of Position Regarding Completeness of Application, filed Jan. 5, 2018; Docket No. 2016-0328, Order No. 34664, issued June 28, 2017 (certifying completeness of the application).

[42] HRS § 269-16(b).

[43] HAR 6-61-57(1).

[44] The scope and schedule of information requests are governed in dockets by procedural orders and schedules issued by the PUC.

review if they have reached an agreement on specific issues.[45] Additional testimony and rebuttal testimony may be taken, and evidentiary hearings may be held on any unsettled issues.[46]

Generally, the PUC reviews and determines the total annual revenues required by each utility to cover projected expenses and provide an opportunity to earn a fair return on investment. The PUC is required by statute to issue its decision as expeditiously as possible, and within nine months from the date the public utility filed its completed application.[47] If the PUC is unable to issue a final decision, it must issue an interim decision allowing an increase in rates, fares, and charges, if any, to which the PUC believes the utility is likely entitled.[48]

3.3.1 Ratemaking for the HECO Companies

For the investor-owned HECO Companies, as discussed below, rates are currently determined using a Cost of Service ("COS") approach supplemented by components associated with PBR, namely, the use of multi-year rate plans, earnings sharing mechanisms ("ESM") between the utility and the customers for the HECO Companies, decoupling using a revenue adjustment mechanisms ("RAM") subject to a revenue cap and using revenue balancing accounts ("RBA"), and recently, performance incentive mechanisms ("PIM"). Moreover, the HECO Companies' rates include an energy cost adjustment clause ("ECAC"),[49] which adjusts rates to recover specific short-term historical fuel prices and purchased energy expenses, and a purchased power adjustment clause, which recovers certain non-energy costs associated with the power purchased from independent power producers.

Under a traditional COS approach, revenue requirements identify the expected amount of revenue the utility requires to cover its COS for a given forward twelve-month period (referred to as a "test year").[50] As shown in the formula below, the revenue requirements are comprised of the rate base multiplied by the allowed rate of return plus the sum of depreciation and amortization expenses, operating expenses, and tax expenses.[51] Under the COS approach, the operating and other expenses, as well as the cost of power, are costs that are passed on to customers and do not provide a "return on investment" to the utilities. On the other hand,

[45] *See, e.g.*, Docket No. 2016-0328, Parties' Stipulated Settlement Letter, filed Nov. 15, 2017.

[46] *See, e.g.*, Docket No. 2016-0328, Procedural Order No. 34721, issued July 28, 2017, at 9-11 (procedural schedule); Docket No. 2016-0328, Order No. 35219 *Amending Procedural Order No. 34721*, issued July 28, 2017, at 7-8,13-14 (revised procedural schedule reflecting settlement and interim order).

[47] HRS § 269-16(d).

[48] HRS § 269-16(d).

[49] While it is a recent development, in Docket 2016-0328, an Energy Cost Recovery Clause ("ECRC") has replaced the ECAC for HECO, due, in part, to the Commission's guidance from Docket 2013-0141 to revise the ECAC. It is expected that HELCO and MECO will also replace their ECACs with ECRCs

[50] *See,* HAR § 6-61-87(4).

[51] *See, generally*, Docket No. 2016-0328.

generally, the rate base (which includes the investments in net utility plant and other items such as regulatory assets and working capital) is multiplied by the PUC-approved rate of return to determine the revenue required. The HECO Companies estimate the rates of return they propose for PUC approval based on "multiple analytical techniques including the Discounted Cash Flow model, the Capital Asset Pricing Model, and the Bond Yield Plus Risk Premium approach."[52]

As shown in the revenue requirement formula below, the utility's ability to increase earnings is tied to increases in the rate base. As a result, the traditional COS approach may create an incentive for the utility to spend more on capital expenditures ("capex") to increase the overall associated returns it receives on investments. This is one of the reasons given for the recent passage of the Hawaii Ratepayer Protection Act.[53]

$$\begin{aligned} &Traditional\ COS\ Revenue\ Requirements \\ &\quad = (Rate\ Base * Approved\ Rate\ of\ Redurn) + Operating\ Expenses \\ &\quad + Depreciation\ and\ Amortization\ Expenses + Tax\ Expenses \end{aligned}$$

The current regulatory framework has some components associated with PBR as well. These include a fixed three-year cycle for general rate cases, the decoupling mechanism, an ESM, an interim-period revenue adjustment mechanism (which includes a revenue cap), and PIMs. The decoupling mechanism consists of an RBA and RAM.

- **Multi-Year Rate Plan ("MRP")**: MRPs permit utilities to operate for several years (typically three to five years) without general rate case.[54] The HECO Companies are on fixed three-year general rate case cycles.[55] A longer rate cycle could further incentivize utilities to reduce operating costs since they would retain the savings for a longer period before the next rate case. Consumers would then benefit from the reduced costs upon the rate reset.

- **RBA Decoupling Mechanism**: Revenue decoupling "de-links" the utility's revenues from the volume of electricity sales. In other words, decoupling aims to eliminate the financial detriment caused by reduced electricity sales which serves as the utilities' disincentive to pursue energy efficiency measures. For utilities, a revenue decoupling mechanism can be favorable, especially if they are encountering declining sales per customer. On the other hand, utilities with increasing sales per customer have a financial incentive to avoid revenue decoupling. RBA is "the sales decoupling component, which is designed to break the link between the HECO Companies' sales and their total electric revenues by setting the target revenues to the most recent authorized revenue level approved in each utility's

[52] *See, e.g.*, Docket No. 2016-0328, Direct Testimonies and Exhibits, Book 9, HECO T-28 Executive Summary, filed December 16, 2016.

[53] *See* 2018 Haw. Sess. Laws Act 5 § 1.

[54] Order No. 35411, at 16.

[55] Order No. 35411, at 41.

most recent rate case."[56] Under the RBA, the HECO Companies recover PUC-approved "Target Revenues" (and no more or less). Base rates are adjusted using a per kWh rate adjustment (the "RBA Rate Adjustment"), which is calculated by dividing a sum, which includes the calendar year-end balance in the RBA balance as well as certain adjustments included in the RAM and PIM provisions by the Company's forecast of MWh sales over the RBA Rate Adjustment recovery period.[57]

- **RAM Decoupling Mechanism**: The RAM is designed to "compensate [the] HECO Companies for increases in utility costs and infrastructure investment between rate cases through formula-driven estimates."[58] Because of the RAM, the HECO Companies do not have to wait until the next general rate case to recover the approved costs and infrastructure investments and instead may do so between rate cases. Items that are subject to yearly update and escalation through the RAM include labor and non-labor O&M and payroll tax expenses, return on incremental investment, updated depreciation and amortization expenses, and changes in costs due to significant changes in tax laws[59] or regulations.[60]

    - **RAM Revenue Cap**: In the event that the RAM Revenue Adjustment exceeds the Target Revenue for the rate case test year, increased by the compound Gross Domestic Product Price Indicator for each year following the test year, it will be capped, and excess expenses will not be recoverable.[61]

    - **ESM**: ESMs are generally designed so that the extraordinary earnings (or losses in some jurisdictions) are shared between the utility and its customers rather than retained (or absorbed) entirely by the utility.[62] In the case of the HECO Companies, the ESM is asymmetrical where only excess earnings (*i.e.*, where utility earnings

[56] Docket No. 2013-0141, Order No. 32735 Modifying Decoupling Mechanisms and Establishing Briefing Schedule, issued March 31, 2015, at 9-10.

[57] *See, e.g.*, Tariff Applicable to Electric Service of Hawaiian Electric Company, Inc., Revenue Balancing Account ("RBA") Provision, *available at* https://www.hawaiianelectric.com/Documents/my_account/rates/hawaiian_electric_rates/heco_rates_rba.pdf .

[58] *Ibid.*

[59] LEI's modeling of the revenue requirements for utility, which drives consumer rates, incorporates the recently lowered federal corporate tax rate of 21 percent.

[60] Order No. 35411, at 43.

[61] *See,* Order No. 35411, at 42-43.

[62] ESMs serve the same basic purpose as clawback mechanisms within a traditional COS framework, ensuring prices do not get too distorted or deviate too much from actual costs. In the context of indexation formulae, an exit ramps can represent an alternative (or complement) to an ESM, triggering an automatic end to the current formulae application period and initiating a COS rate review.

are greater than the authorized return on equity ("ROE")) are shared with the customers. This means that where there are no excess earnings (*i.e.*, earnings are at or below the authorized ROE), any lower than expected earnings will be fully absorbed by the utility's shareholders and not by its ratepayers. If the actual ROE is more than 100 basis points or 1% over the authorized ROE, customers will be credited a 25% share. If the actual ROE is more than 200 basis points or 2% over the authorized ROE, the customers will be credited a 50% share. If the ROE exceeds 300 basis points or 3% of the authorized ROE, the customers will be credited a 90% share.[63]

- **PIMs:** PIMs consist of metrics, targets, and incentives used to address performance and provide regulatory guidance and incentives regarding the implementation of new technologies and practices.[64] PIMs are generally put in place to ensure that any cost reductions implemented by the utility will not cause the deterioration of service quality.
    - **Service Quality (Traditional) PIMs:** Currently, the HECO Companies' rates are based in part on penalty PIMs, which are determined by the achievement of service outage frequency ("SAIDI") and duration ("SAIDI") metrics as well as a PIM for call center performance, which provides either a penalty or a reward.[65]
    - **Targeted Energy Policy PIMs:** The PUC has approved incentive PIMs related to the HECO Companies' achievement of cost savings in renewable generation procurement as well as the implementation of the HECO Companies' demand response portfolio.[66]

These PBR elements are incorporated into the HECO Companies' rates using the RBA Rate Adjustment.[67] This is independent of the establishment of the HECO Companies' base rates for each rate case test year based on traditional COS methods.

3.3.2 Ratemaking for KIUC

For KIUC, a member-owned co-op, rates are determined using a debt service coverage COS approach known as the Times Interest Earned Ratio ("TIER"). Moreover, KIUC's rates include an

[63] Order No. 35411, at 43.

[64] Order No. 35411, at 17.

[65] Order No. 35411, at 44-46.

[66] Order No. 35411, at 46-47.

[67] *See*, Tariff Applicable to Electric Service of Hawaiian Electric Company, Inc., Revenue Balancing Account ("RBA") Provision, *available at* https://www.hawaiianelectric.com/Documents/my_account/rates/hawaiian_electric_rates/heco_rates_rba.pdf

Energy Rate Adjustment Clause ("ERAC"), which recovers specific variable fuel and purchased energy costs.

KIUC's revenue requirement calculation is based on somewhat different principles than those used for the HECO Companies. KIUC's revenue requirement target is mainly designed to meet its debt obligations rather than provide a return for shareholders. KIUC's equity is held primarily by its customer-members, who make contributions for service and not with a set expectation of receiving a return. Therefore, the revenue requirements of a co-op are set using a TIER level. TIER is a solvency ratio that measures a co-op's ability to meet its long-term debt obligations. It is calculated by dividing the net income before interest and taxes by annual interest expense. Net income is essentially operating margin in the case of KIUC. The formula for the TIER level is shown below:

$$TIER = (Net\ Income\ Before\ Interest\ and\ Taxes)/(Interest\ Expense)$$

The ratio measures how many times KIUC can cover its interest expenses from its pre-tax earnings. Although the United States Department of Agriculture's ("USDA") Rural Utilities Service ("RUS") loan agreements require a minimum TIER of 1.25[68] for distribution utilities, the PUC has set the current regulated TIER level for KIUC at 2.27.[69] A co-op's net margin for that year is the operating revenue remaining after operating expenses, and debt service is paid for. The revenue requirement for KIUC is set so that it earns a sufficient margin to achieve the target TIER level. This margin helps KIUC to maintain financial stability and make the necessary investments on the grid.

The following can be inferred from the formula for TIER level:

$$TIER = (Interest\ Expense + Margins)/(Interest\ Expense)$$

$$TIER = (Revenues - Operating\ Expenses)/(Interest\ Expense)$$

$$Revenues - Operating\ Expenses = Interest\ Expense * TIER$$

$$Revenue\ Requirement = Interest\ Expense * TIER + Operating\ Expenses$$

KIUC's revenue requirement is a function of the interest expense, TIER level, and operating costs:

1. Interest expense
   a) Capital structure helps to determine how much debt can the co-op carry. A higher debt-capital ratio increases the interest expense, thus, the revenue requirements.
   b) Interest rates are lower for co-ops than IOUs. Co-ops have access to low-cost debt from public and private sources that IOUs do not, enabling them to lower their financing cost.

[68] *See* Docket No. 2009-0050, Application, Volume 1, filed June 30, 2009, at 10.

[69] Docket No. 2009-0050, Decision and Order, issued September 9, 2010, at 1-2.

2. TIER level – set by the regulator.

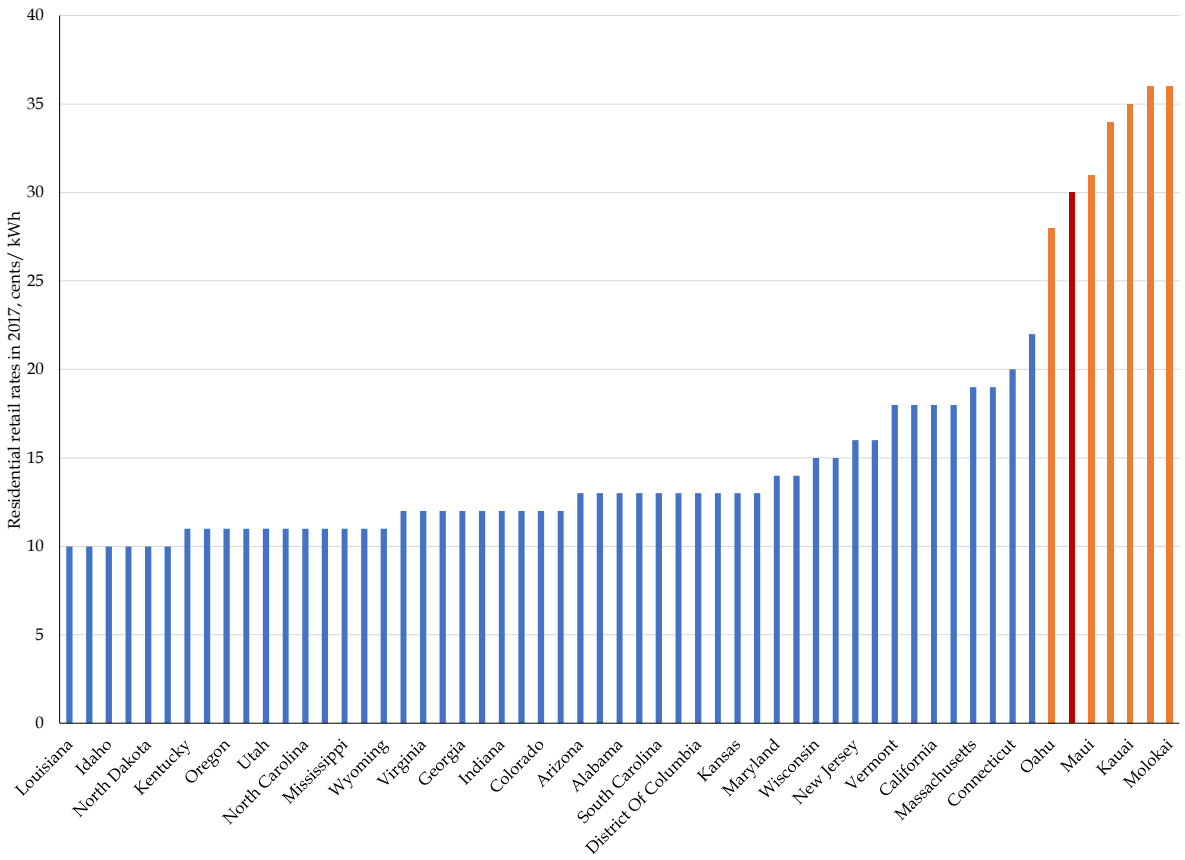
3. Operating costs – generally the same as for IOU, with the exception that tax expenses are lower for co-ops because they are exempt from federal income taxes.

Task 2.1.2 *(Current regulatory model)* provides a more detailed discussion of the current ratemaking process in Hawaii.

3.4 Electricity rates

Residential electricity customers in the State of Hawaii pay the highest rates among US states, averaging around 30 cents per kWh in 2017, which is more than twice the national average of about 13 cents per kWh (Figure 16). According to the Energy Information Administration ("EIA"), the high retail electricity rates mainly result from the State's dependence on imported petroleum combined with isolated island grids.[70]

Figure 16. Electricity rates in select US states (2017)



Source: EIA. HSEO.

[70] "State Profile and Energy Estimates: Hawaii". *EIA*. <https://www.eia.gov/state/analysis.php?sid=HI>

Residential electricity rates are lower on Oahu than on other islands. In 2017, the customers on the islands of Lanai and Molokai paid the highest average rate of 36 cents per kWh; the rate was slightly lower, approximately 34 cents per kWh, on Hawaii and Kauai islands. The average rate on Maui Island was close to the state average (30 cents per kWh) and slightly higher than the rate on Oahu (27 cents per kWh).

Most industry stakeholders and participants to the community dialogues identified high electricity rates as the most critical factor that should be considered in performing the Study.

4 Potential utility ownership models

4.1 Description of the potential ownership models

A wide range of ownership structures for utilities (or companies providing utility-like services) can be observed around the world. Furthermore, technological change is enabling the exploration of new types of ownership arrangements. For this Study, the Project Team defines a *utility* as an entity that is entitled to earn a fair return through charging regulated rates for essential service in return for assuming an obligation to serve; as per terms of the study, the Project Team focused solely on the electricity sector. Eight different ownership structures were selected based on both the scope of work provided and the assessment of various additional potential arrangements. While this list of ownership structures is not exhaustive, it is representative of both existing and emerging alternatives.

The eight potential utility ownership structures considered were:

(i) investor-owned utility – status quo in all counties except Kauai;

(ii) new parent company to IOU;

(iii) cooperative – status quo in Kauai county;

(iv) municipal;

(v) hybrid with majority government ownership in IOU;

(vi) integrated distributed energy resources operator model;

(vii) SB; and

(viii) grid defection/dispersed ownership.

Since there can be different possible implementation of various ownership models, the Project Team described them in a way that encompasses the most common forms. However, each can be further customized to meet the needs of the state of Hawaii or the individual Hawaiian Islands.

4.1.1 IOU

An IOU can be a publicly traded or privately held company. National data indicates that 189 IOUs serve 68% of US electricity customers.[71] In the case of HEI, it is traded on the New York Stock Exchange with 50.0% of shares held by institutions.[72] However, in recent years, several IOUs have been taken private by companies like Berkshire Hathaway or Macquarie; the potential for a new parent is discussed in the next section. Being publicly traded can impact management planning horizons; because public companies report earnings quarterly, some observers contend that this leads to a shorter-term management mentality.

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[71] American Public Power Association. *2015-2016 Annual Directory & Statistical Report*. <http://www.publicpower.org/files/pdfs/uselectricutilityindustrystatistics.pdf>

[72] Hawaiian Electric Industries, Inc. *Institutional Ownership*. Website. <http://www.nasdaq.com/symbol/he/institutional-holdings>.

To ensure transparency and checks-and-balances, the IOU's management reports to a board of directors, which has a fiduciary duty to its shareholders. Legislators and regulators of the jurisdiction where the IOU operates set the framework for the IOU's activities based on public policy targets. Naturally, IOUs are expected to make prudent investments so that they can provide reliable service consistent with good utility practice.

IOUs in Hawaii

Hawaiian Electric Industries supplies power to approximately 95% of Hawaii's population through its electric utilities, including Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Ltd. ("MECO"), collectively known as the HECO Companies. In addition, HEI owns the financial institution American Savings Bank, F.S.B.

Number of customers (2016): 460,000 (Electric Utilities)

Total assets (2016): 5,975.43 million (Electric Utilities)

Total revenue (2016): 2,094.37 million (Electric Utilities)

Source: HEI Form 10-K. Energy Information Administration ("EIA") Schedule 4 Part A, B and C

Often, the best way for IOUs to increase profits is to pursue additional capital investments. While regulators have attempted to change incentives by redesigning the utilities' revenue requirement calculation, IOUs are conditioned to plan according to a return on rate base since profit growth is mostly linked to rate base growth.[73] As regulatory regimes evolve to incorporate a higher degree of incentives and performance-based elements, the mindsets of the utility, its customers, and its regulators need to change.

4.1.2 New parent

The implications of new ownership depend on the nature of the new parent. For example, IOUs can be owned by other IOUs, private equity firms, or conglomerates. Similarly, the new parent could also be a not-for-profit, a limited dividend, or a benefit corporation ("B corp."). It is possible that ownership by another larger publicly traded IOU may provide greater access to capital or human resources to the incumbent utility. Indeed, private equity ownership can prevent a 'quarterly mentality' by IOU's management. However, the business model of some private equity firms includes a holding period (e.g., of five to ten years) after which assets are expected to be monetized. Some firms such as Berkshire Hathaway (publicly traded but mostly a conglomerate) have assembled vast collections of IOUs across geographically diverse territories. Historically, the acquisition of a utility by a new parent has, in some instances, led to growth and innovation. This has been shown in the experience of Green Mountain Power in Vermont, the first utility to

[73] Cost of service ("COS") is the starting point for all regulatory frameworks for regulated utilities. For this paper, the Project Team assumed that the COS is constant across all the ownership models reviewed. Performance-based ratemaking ("PBR") regimes build upon COS principles, including calculation of rate base, target fair returns, and cost allocation studies.

be certified as a B corporation. However, the transaction can also lead to significant indebtedness and potential distress. The ill-fated takeover of Texas Utilities is a case in point.

Benefit corporations ("B Corp")

B Corps are for-profit corporate entities that are certified by the nonprofit B Lab to meet rigorous standards of social and environmental performance, accountability, and transparency. As a B Corp, a corporation can legally mandate social and environmental considerations other than just profit. As a result, directors possess necessary legal protection to consider the interest of all stakeholders, rather than just the shareholders who elected them.

In Hawaii, Senate Bill 298 was passed into law in 2011 as Act 209 to allow businesses in Hawaii to operate under a B Corp or sustainable business corporation structure. As of July 2017, there are seven B Corps in Hawaii, including bCause, Natural Investments LLC, Smart Sustainability Consulting, Hawaiian Legacy Hardwoods, Hawaiian Ola, Hawaiian Paddle Sports, LLC, and Sustainable Pacific Consulting.

Meanwhile, a significant number of for-profit companies are controlled by not-for-profit entities. A good example is Mountain View Power, which is an energy marketer in Alberta, Canada. Owned and managed by the Olds Institute for Community and Regional Development ("the Olds Institute"), it sells electricity and natural gas to residential, farming, and small business clients in Mountain View County. The Olds Institute is a non-profit community and economic development organization, owned by the community, and driven by volunteers.

4.1.3 Co-op

Co-ops are owned by members who are also the customers. They are incorporated under the laws of the state in which they operate. This type of ownership is not limited to utilities. For example, credit unions are often structured like co-ops. KIUC is an example of a co-op operating in Hawaii. In Hawaii County, a group of stakeholders has formed a co-op for the ultimate purpose of purchasing and operating HELCO's assets.

Electric co-ops can be structured based on key business areas: (i) generation and transmission ("G&T") co-ops; (ii) distribution co-ops; or (iii) both. G&T co-ops provide wholesale power to distribution co-ops through their generation or by purchasing power on behalf of the distribution members while distribution co-ops deliver electricity to the customers. Currently, around 42

million people in 47 states in the US are serviced by 834 distribution and 63 G&T co-ops.[74] The electric co-ops also own and maintain 2.6 million miles of distribution lines, which is the equivalent of 42% of the nation's total.[75] They generate nearly 5% of the total electricity produced and deliver 11% of the total kilowatt-hours sold in the US annually.[76]

Co-ops often enjoy autonomy and independence. They are controlled by members and governed by a board of directors, allowing transparency and democracy. In typical setups, co-op members have equal voting rights (practicing the *one member, one vote* principle). The board is expected to set major policies and procedures (which are, in turn, expected to be implemented by the management), advocate for reforms on behalf of members, approve annual operating budgets, capital expenditure budgets, and compensation plans, recruit and select a CEO, and appoint an independent auditor to perform an annual financial audit.

Co-ops have no equity other than retained earnings (revenue which has not been returned to members) but have access to concessional financing via the Rural Utilities Service ("RUS"),[77] National Rural Utilities Cooperative Finance Cooperation, and the National Cooperative Services Corporation.[78] Co-ops enjoy tax advantages such as a tax-exempt status under IRC Task 501(c)(12) (provided that 85% or more of their annual income comes from members). However, this also means that they cannot take advantage of various incentives that are provided through the tax code—examples of which include investment tax credits, accelerated depreciation, and production tax credits.

Kauai Island Utility Cooperative: an operational electric co-op in Hawaii

KIUC provides electric service on the Kauai island. On November 2002, KIUC became the first electric co-op in Hawaii when it purchased the electric utility from Citizens Communications.

Number of customers (2016): ~37,000

Total assets (2016): $381.5 million

Total revenues* (2016): $143.5 million

Note: Operating Revenues*
Source: Kauai Consolidated Financial Statements (December 31, 2016 and 2015), KIUC website. EIA Schedule 4

[74] National Rural Electric Cooperative ("NRECA"). "Electric Co-op Fact Sheet." <https://www.electric.coop/electric-cooperative-fact-sheet/>

[75] Ibid.

[76] Ibid.

[77] An agency of the US Department of Agriculture.

[78] CFC provides financing to its members for non-profit services while NCSC can lend to members, non-members, and for-profit entities as long as the activity benefits the cooperative network.

4.1.4 Municipal ownership

There are instances when cities and towns prefer to own and manage their municipal utilities ("munis"). About 15% of US electricity customers are served by 2,013 municipal utilities.[79] Many municipal utilities arose out of public works departments in various cities and towns; over time, these assumed a separate corporate identity from the cities that own them and that they serve.

Municipal ownership has both advantages and challenges. For example, municipal utilities may benefit from access to tax-exempt debt financing. They may also be tax exempt as well as exempt from various kinds of State and Federal regulations. However, by the very nature of their ownership, munis can be subject to political interference, making it difficult for them to pursue long-term strategies. Munis can be governed by the city council, a local board, or an independent board, which would impact the effectiveness of how the muni is managed. When the city council dominates the utility's management, utility rates and service policies are set by these local entities, and there are often issues related to income retention. For example, the muni may experience pressure to transfer dividends to its municipal parent. In these circumstances, muni rates may be viewed as a substitute for tax revenues. This pressure prevents them from mobilizing funds for investment. However, when there is a more independent board supervising the utility, it can operate without as much political pressure. Similar to co-ops, the only source of equity for municipal utilities is retained earnings (unless the city chooses to inject funds).

Austin Energy: A muni of similar size to HECO

Austin Energy is a large municipal utility, serving a similar number of customers to HECO - more than 461,345 customers as of 2016. It operates within the Electric Reliability Council of Texas. The operations of Austin Energy are funded entirely through energy sales and services, and the utility further supports the City of Austin and its departments through an annual transfer into the general fund of more than $100 million.

Number of customers (2016): 461,345

Total assets (2016): $4,383 million (Electric Utilities)

Total revenue (2016): $1,370 million (Electric Utilities)

Source: Velocity Suite and Austin Energy 2016 Annual Summary Report.

4.1.5 Hybrid, majority government-owned

Hybrid ownership models exist, but in almost all cases, they evolved following the involvement of private sector partners in utilities which were formerly 100% government owned. For example, a number of European utilities continue to have a high degree of state ownership despite private sector involvement. Another good example is Malaysia's largest utility, Tenaga Nasional Berhad ("TNB"), which continues to be 41.15% government owned. There are also instances when governments acquire controlling stakes in existing private utilities, which they do not intend to

[79] American Public Power Association. *2015-2016 Annual Directory & Statistical Report*. <http://www.publicpower.org/files/pdfs/uselectricutilityindustrystatistics.pdf>

expropriate. Understandably, governments follow different strategies in holding and managing investments in utilities.

In some cases, shares are held directly by the relevant Department, indicating a greater desire to use the utility as a tool for implementing government policy. In other cases, the utility stake is held by a government-owned investment fund that employs professional managers to ensure that state-owned companies are managed economically efficiently. Singapore is an example of a government that practices the latter approach.

Hybrid government-majority owned example #1: Hydro One

Hydro One is an electricity transmission and distribution utility serving the province of Ontario in Canada. As of March 31, 2017, the province of Ontario owns 70.1% of the utility.

Number of customers: 1.3 million

- Transmission: 44 local distribution companies and 87 large industrial customers connected directly to the transmission network.
- Distribution: Over 1.3 million residential and business customers

Total assets (2016): CAD $25.35 billion

Total revenues (2016): CAD $6.55 billion (includes both regulated and unregulated businesses)

Note: Exchange rate in 2016 (average): US$ 1 = CAD $1.325
Source: Hydro One Investor Fact Sheet – 2017 and Hydro One 2016 Annual Report

Hybrid government-majority owned example #2: Tenaga Nasional Berhad

TNB is the largest utility not only in Malaysia but also in the Southeast Asia region. It serves customers in Peninsular Malaysia, Sabah, and Labuan.

Number of customers: 9.2 million

Total assets (2016): RM 132,902.2 million

Total revenues (2016): RM 44,531.5 million

Note: RM = Ringgit Malaysia
Exchange rate in 2016 (average): US$ 1 = RM 4.142
Source: TNB 2016 Annual Report

State-controlled utilities are often adept in mobilizing funds primarily because government involvement leads to a 'halo effect'—investors assume that such utilities enjoy backing from the government. Hybrids are considered more advantageous by their proponents because they can raise equity on the stock market instead of relying solely on retained earnings. This is often not possible in co-ops and munis. However, government owners often impose certain limits, mainly if they are concerned about the dilution of control. This was observed in Ontario when the provincial government addressed this issue by capping the stake that any single entity can purchase. Meanwhile, the United Kingdom ("UK") has retained a so-called "golden share" after privatization. This grants the government special rights such as the ability to block a merger.

Often, hybrid entities enjoy exemptions from civil service restrictions and are somewhat insulated from political interference. However, minority shareholders may place a lower value on the utility's equity if the government is perceived to be a less profit-oriented shareholder. Public shareholders will be attentive to whether government ownership is depressing profits by influencing the utility to undertake initiatives that lack a strong commercial basis.

4.1.6 Integrated distribution energy resources ("IDER") system operator

An IDER system operator represents a new approach to utility ownership. This model does not currently exist in a fully deployed manner. However, the State of New York is moving toward implementing such a model. The utility in an IDER model is confined to the wires portion of the business and is required to provide open access to all DERs connected to it at a tariff allowing for the recovery of the utility's costs. The utility or another entity is in charge of coordinating flows across the grid. Generation would be moved to a competitive subsidiary, with appropriate consideration of stranded costs, if any. The utility may or may not provide a "standard offer" for DERs, who would be free to accept that standard offer or to contract with other customers bilaterally while paying for the use of the utility's lines. Under the IDER model, the utility would optimize the system, and in theory would have no incentive to discriminate against third-party assets, or between DERs and transmission.

IDER model example: New York's Reforming the Energy Vision ("REV")

In recognition of the rapid advancements in DER, the New York Public Service Commission ("PSC") initiated the Reforming the Energy Vision ("REV") proceeding which became a multi-pronged strategy of the state to develop a clean, resilient, and affordable energy system for all New Yorkers. It prioritizes energy efficiency and clean locally produced power. It also encourages deeper penetration of DER and engages end-users through the creation of a more local, distribution network-oriented market structure facilitated by utility as distribution system platform ("DSP") provider. The idea is to reform the traditional utility business model so that integrating DERs from third party providers is a crucial feature and to ensure that utilities are incentivized to consider DER solutions as an alternative to traditional grid investments.

The PSC directed the six large IOUs in the state to develop and file demonstration projects to test new approaches to distributed resource adoption. One of these demonstration projects is National Grid's DSP project with the Buffalo Niagara Medical Campus. In this project, National Grid is testing how it can integrate customer-owned energy resources to manage system demands. According to the implementation plan, this project is currently in "Technology Development" (Phase 2) stage of the project. The proponents are due to start the field demonstration (Phase 3) in September 2017 and they plan to complete the evaluation/report dissemination by October 2018.

Source: New York Public Service Commission, National Grid

The IDER model can lead to:

- a diversity of ownership structures for generation;
- increased potential for embedded or connected microgrids;
- increased adoption of new technologies such as blockchain to allow peer to peer transactions; and
- increased ability to optimize services across a range of technologies and grid linkages.

The model could deepen community ownership and help ensure that there would not be a dominant entity in the ownership of generation assets. IPPs, former rate base generation, and co-op or municipal generation assets could co-exist. However, such a structure would work more effectively if existing utility costs are appropriately unbundled, and open access is enforced. Nevertheless, this model has not yet been proven in practice and still needs time to evolve.

4.1.7 Single Buyer

The SB approach includes a number of variants worldwide. In some cases, the SB is established as a stand-alone, not-for-profit entity. In other cases, it is part of an Independent System Operator ("ISO"). In yet another variant, the utility itself takes on the SB role while being barred from or constrained in the ability to bid its own projects in SB procurements. An entity like the proposed HERA could fulfill this role.[80] HERA could also take on the role of system operator as envisioned in the IDER model.[81] Alternatively, the HECO Companies themselves could act as the SB, but appropriate safeguards should be in place to ensure that they are operating in a fair and transparent manner in such a scenario. This model is different from the current competitive procurement process that the HECO Companies have in place, as the SB envisioned under this model would require the establishment of a new legal entity that would be appropriately ring-fenced from other HECO Companies' business entities. Furthermore, the SB entity would assume the planning for the transmission system and resource adequacy.

[80] The Project Team notes that Act 166 authorizes the PUC to develop, adopt, and enforce reliability standards and interconnection requirements, and to contract for the performance of related duties with a party that will serve as the HERA, but does not include the SB functions mentioned here. Therefore, an amendment to the Act may be needed to include the SB and grid access oversight functions.

[81] In Singapore, the Energy Market Authority ("EMA") is the electricity and gas industry regulator. Unusually, EMA also takes the role of a Power System Operator ("PSO") and is responsible for the reliable supply of electricity to the consumers.

Single Buyer example: Tenaga Nasional Berhad

TNB is Malaysia's sole electric utility company. It was formed in 1990 as a government-owned corporation. In the 1990s, it was a vertically integrated utility, and owned the majority of generation, in addition to T&D. IPPs provided some competition in generation. TNB also conducted energy procurement from the IPPs. However, further reforms in the Malaysian Electricity Supply Industry led to the creation of the Single Buyer in 2012, a ring-fenced entity within TNB.

TNB's Grid System Operator and Single Buyer are both ring-fenced from the other business entities of TNB. Below are some of the ring-fencing measures imposed within the company.

Item	Grid System Operator ("GSO")	Single Buyer
Work area	Separate from the work areas of other divisions and units within TNB	Separate from the work areas of other divisions and units within TNB
Sharing of information	The ownership of all data in the principal operational systems used by GSO, all other data jointly by the GSO and Single buyer, and the data held in corporate or shared administrative system relating to GSO' operation or staff, shall be rest with GSO GSO shall not disclose any information that is confidential to TNB or any other party	The Single Buyer shall not disclose any information that is confidential to TNB or any other party, or information that may provide competitive advantages to any other party
Accounts	Needs to maintain a separate set of Financial Statutory Accounts, which is audited at least annually and published on the GSO's website	A separate set of Single Buyer Accounts relating to the performance of its functions as a Single Buyer should be maintained and established
Access to IT system	1) Only GSO staff can access systems that are only used by the GSO; 2) 2) shared systems are partitioned so that staff of other divisions only have information that they require in their performance and that won't provide them with competitive advantages; 3) 3) a record is maintained of the date and time that each information item is accessed and/or changed by each user of GSO's IT system.	Other users of the IT system cannot access confidential information held by the Single Buyer
Compliance report	Prepare a statement of compliance, and the GSO shall identify a full-time "Compliance Officer" who manages the compliance arrangements	Prepare a statement of compliance, issue guidelines, and provide supporting information to justify compliance

Source: Tenaga Nasional Berhad website, Electricity Tariff Regulation Implementation Guidelines

Generation ownership under the SB approach could also be diverse as in the IDER model. If the SB is a stand-alone, not-for-profit entity or an ISO, the SB itself does not own generation or wires assets; it is merely a contracting agency. However, what differs here is the need for all grid-connected DERs to forge contracts with the SB instead of bilaterally. The SB would procure generation based on an integrated resource plan ("IRP") or another planning mechanism, similar to aspects of HECO Companies' PSIP or IGP. Ideally, the SB would be technology and ownership model neutral, procuring power and planning grid investments at the least cost for the system and passing its costs to ratepayers. *Technology neutral* means that the SB would consider storage and assess tradeoffs between/among wires, generation, storage, and behind-the-meter solutions.

4.1.8 Grid defection

Grid defection is a situation in which customers reduce their reliance on the grid and ultimately stop using it. Under a grid defection scenario, parts of the grid may need to be abandoned; stranded costs could emerge in both generation and wire assets. Grid services could deteriorate, and the cost of serving underprivileged customers would increase. Generation ownership would be diverse, and microgrids (also under diverse ownership) would proliferate. Customers would effectively receive the level of reliability they wished to pay for, but the ability to pay or access to knowledge to self-supply would be a challenge for some customers. Overall, grid defection would become more likely over time if delivered costs are higher than DER costs and no action is taken to encourage alternative business models.

Task 1.1.1 *(Introduction of ownership models)* provides a more detailed discussion on the potential utility ownership models explored in this Study.

Lessons from TransCanada Mainline

A parallel example, although not a perfect analogy to this discussion, is emblematic of what happens when a firm formerly perceived as a natural monopoly is no longer one, is the case of the TransCanada Mainline. This example showcases the impact of competition on customer rates. TransCanada Mainline, one of the largest natural gas systems in Northern America, started operations in 1959. Until 1998, TransCanada mainline faced limited competition.

Starting in the 2000s, however, the competitive landscape began to shift as more competitors including Alliance and Vector pipelines began providing gas transmission services in the region. Due to the growing supply of gas, the amount of gas transported by the TransCanada Mainline significantly declined and resulted in substantially higher fixed costs and toll prices. In response, TransCanada presented a toll restructuring proposal to the National Energy Board ("NEB") in which it requested to shift $400 billion in yearly costs to users of the Alberta system. After further proceedings, the NEB decided to implement a long term fixed competitive price for tolls for a four-year period.



Source: TransCanada Mainline Decision

4.2 Advantages and drawbacks of each ownership model

The Project Team has assessed and compiled the pros and cons of each of the utility ownership models. This assessment is based on research and is informed by participants during community

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outreach events. The results are summarized in Figure 17. When viewed in light of the State's goals and energy objectives, the pros and cons assessment confirms that the ownership models selected for further evaluation (IOU, co-op, and SB models) may be best suited to Hawaii's context.

Figure 17. Summary of pros and cons of each utility ownership model

	Pros	Cons
IOU	• Has greater access to capital and human resources	• Goals of shareholders are not always aligned with State goals
New parent	• Can facilitate growth and innovation • Has various sources of capital	• May lead to potential financial distress if acquisition is heavily leveraged
Co-op	• May have access to concessional financing (via Rural Utilities Service, National Rural Utilities Co-op Finance Cooperation) if considered "rural" • Align stakeholder interests	• Strength of leadership may vary based on outcome of board elections • Local population might be unengaged or uninterested in electric utility management
Muni	• May benefit from access to tax exempt debt financing • They themselves may also be tax exempt, and exempt from various kinds of state and Federal regulations	• Difficulties in recruiting employees with adequate technical skills needed to run utility • May be subject to political interference and may face difficulty in mobilizing funds for investment
Hybrid (with majority government ownership)	• Little trouble mobilizing funds (as state-controlled utilities) • State ownership can present "halo" effect for raising capital; can raise equity on stock market instead of solely relying on retained earnings • Exempt from civil service restrictions	• Potential political interference • Conflicting incentives between entities on the board
Single Buyer	• Allows for optimized grid reliability, coordinated planning in sync with State goals, and competition for generation • Could lower rate levels by procuring energy in efficient manner • Technology and ownership model neutral	• Requires establishment of independent entity (for SB outside of the utility) • Need for amendment to Act 166 to include SB and grid access oversight functions
IDER	• IDER is independent but guided by state policy objectives • Creates distribution network of the future; explicitly targets creating a competitive distribution system	• Complex solution: redefines role of the utility, requires additional infrastructure and expertise • Would require significant investments to establish the institutions and infrastructure necessary
Grid defection	• Grid connections will ultimately be seen by customers as an option and valued accordingly	• Stranded costs could arise in both generation and wires • Cost to serve underprivileged customers would rise • Ability to pay, or access to knowledge for self-supply, represents a challenge for some customers

4.3 Similarities and differences between ownership models

The role of the utility is one of the key differentiating features of the various ownership models. The utility would still exist in all the models; nevertheless, there are differences in its ultimate goal and how profits (or surpluses, in the case of a co-op) are distributed.

The role of the regulator also changes under some of these models. Under a co-op or muni, the regulator would have less of an impact on setting rates or reviewing resource planning

documents. However, the regulator might still be involved in setting reliability standards and regulating access to the grid. In all other models, the regulator would still be heavily involved in setting rates and approving investment plans. It would also have a responsibility in ensuring the fairness of procurements under the SB model, and in evaluating the effectiveness of integration and equality of access to the grid under the IDER model.

Responsibility for planning also differs among the models. Under the status quo and the other utility-centric models, the utility is responsible for planning with oversight from the regulator. Under the IDER model, utility planning likely shifts to the planning of the wire assets, with market forces driving generation location and planning (although some backstop planning for resource adequacy is likely required and may remain with the utility). Under the SB model, the SB is likely responsible for transmission and resource adequacy planning activities. Of course, in a grid defection world, planning becomes challenging as the utility will increasingly lack the means of implementing the plan. In such a scenario, planning likely defaults to the regulator and focuses on access for low-income customers.

Another area of distinction among the models is related to generation ownership and revenue streams. Under the utility-centric models, generation would continue to be included in the rate base and could be developed by the utility. Under the IDER and SB models, however, all or a portion of the generation assets could be taken out of the rate base. For future procurements, in the IDER model, non-regulated utility affiliates could still own generation resources, but they would be subject to greater regulatory scrutiny to ensure a level playing field. By contrast, in the SB model, provided the utility itself does not act as the SB, non-regulated utility affiliates would face less scrutiny because there would be less opportunity for favoritism.

Another potential area of distinction among the models is taxation. While various so-called "payment instead of taxes" or "Pilot" programs can be designed, co-ops and munis face different treatment with regards to property, local, state, and Federal taxes. Without a Pilot program, the creation of a co-op or muni can result in loss of local and state tax revenue.[82] Because the IDER and SB models involve greater participation by non-utilities, the impact on any taxes collected through the utility would need to be assessed. Under the grid defection model, both utility sales of electricity and sales for resale would be lower, and tax revenue would come from sales of DER equipment.

4.4 Evaluation of the ownership models relative to state goals

The Project Team evaluated the selected ownership models based on the four policy objectives established by House Bill 1700 (Act 124) of 2016, selecting six major criteria from which to assess an ownership model's ability to satisfy these policy objectives. The identified ownership models were qualitatively evaluated relative to the following criteria:

1. ***Ability to meet state energy goals***
2. ***Maximize consumer cost savings***

[82] While federal taxes would also be impacted, this is outside of this Study's scope except to the extent that it impacts rates.

3. ***Enable a competitive distribution system***
4. ***Address conflicts of interest***
5. ***Align stakeholder interests***
6. ***Assess transition costs***

The table below summarizes the relationship of each evaluation criterion to the guiding principles, while the paragraphs below provide further information.

Figure 18. State policy objectives and evaluation criteria

State policy objectives	Evaluation criteria	Notes
1) Achieve State energy goals	• Ability to meet State energy goals	Assess each model's ability to meet the State energy goals
2) Maximize consumer cost savings	• Maximize consumer cost savings • Assess transition costs	Consumer costs include both ongoing costs under the model, plus any cost associated with transitioning
3) Enable a competitive distribution system	• Ability to support a competitive distribution system	Assess each model's ability to allow for competition at the distribution level
4) Eliminate or reduce conflicts of interest	• Address conflicts of interest • Align stakeholder interests	Remove the potential for conflicts of interest in utility investments, and align incentives for all stakeholders

Ability to meet state energy goals

The ability to achieve state energy goals is explicitly listed as one of the four guiding principles and is a criterion which can be qualitatively assessed. Hawaii has the most aggressive renewable energy targets in the country. It aims for its utilities to achieve 100% of their electricity from renewable energy by 2045.[83] Also, Hawaii's energy policy focuses on its "commitment to maximizing the deployment of cost-effective investments in clean energy production and management to promote the State's energy security."[84] More specifically, the State aspires to achieve a diversified energy portfolio that makes the best use of land and resources; have an efficient marketplace that is beneficial to all and integrated and modernized grids, and be recognized as an energy innovation center.[85]

[83] HI Rev Stat § 269-92 (2015).

[84] HI Rev Stat § 269-92 (2015), Hawaii Senate Bill 198 (December 1, 2011), and Hawaii State Energy Office. Energy Policy. Accessed on July 20, 2017. http://energy.hawaii.gov/energypolicy.

[85] Ibid; Hawaii House Bill 416 (January 26, 2015), and House Bill 1494 (December 17, 2015).

While many of the ownership models can be made to meet most or all of the state's objectives, they differ in terms of effectiveness and the extent of regulatory intervention required. Ironically, government ownership forms (state control or muni ownership) may have greater challenges, given the potential susceptibility of these forms to short term political pressure. Grid defection is also a poor means of meeting the state's goals because although it would achieve diversification of energy resources, it would not be able to meet the other objectives. The Project Team's qualitative scoring suggests that the IDER and SB models would best help the state achieve its goals because they would be independent but guided by state policies.

Maximize consumer cost savings[86]

Maximizing customer cost savings is also one of the four major criteria and can be assessed from both a qualitative and quantitative perspective. The SB is the most favorable on the ability to maximize consumer cost savings because it is an independent body focused on long-term least-cost procurement. The co-op model scored second because of its ability to share surpluses with members, though there is the possibility that the co-op management may not always pursue long term least cost initiatives because the co-op' priorities are driven by its members-consumers' interests and needs and these might not always be the least cost. The IOU model is least favorable, largely due to the incentives under the cost of service regulation to over-capitalize the system. However, as noted above, if the profit motive can be appropriately harnessed, IOUs can be an effective means of delivering state policy. Munis rank low in this category primarily because of the risk that they will face pressure to pay above-market wages due to civil service rules and political considerations. Grid defection will not maximize savings; indeed, for those customers who remain with the utility, grid defection will mean a substantial increase in costs.

Enable a competitive distribution system

Enabling a competitive distribution system is one of the guiding principles and can be assessed from a qualitative basis. None of the traditional approaches to utility ownership models will enable a highly competitive distribution system. IOUs, munis, and co-ops all contain bureaucracies inimical to the promotion of new types of generation ownership, evolving ways to connect consumers, and bi-directional flows on the distribution system. The IDER approach is the best way to create the distribution network of the future, as it explicitly targets creating a competitive distribution system. While grid defection ranks second in this category, it lacks the benefits of coordination that an IDER structure would bring. Although the SB model would also facilitate competition, it retains a centralized approach to procurement which could undermine initiative and creativity.

Address conflicts of interest

Addressing conflicts of interest is one of the four guiding principles and can be assessed on a qualitative basis. Addressing conflicts of interest requires as much as possible separating planning and operational control from investment and ownership. Thus, many of the mechanisms which score well under the objective of creating a competitive distribution system also score well in addressing conflicts of interest. Even though grid defection is ranked relatively

[86] The consumer cost savings considered in this section excludes consideration of implementation costs.

high in this metric, this may not be socially optimal. While those defecting from the grid entirely pay their full costs, they clearly no longer participate in a shared endeavor that allows for optimization among customer classes. This is why grid defection scores so poorly in the next category, aligning stakeholder interests.

Align stakeholder interests

The ability to align stakeholders (PUC, CA, Legislature, Utility, and Consumers) interest is one of the six major criteria as aligning stakeholders is necessary to achieve the four guiding principles. A competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs requires stakeholder alignment so that market participants are not working at cross purposes and stifling progress. Stakeholder alignment is also necessary to eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation, as moving forward, no one entity will have complete control over the buildout of grid resources. The extent to which any of the alternatives helps to align stakeholder interests partly depends on the regulatory framework in which it is embedded. Thus, while the separation of ownership, procurement, and operation principle continues to apply, the Project Team has not ruled out the possibility that a properly regulated IOU could align stakeholder interests; this could mainly be the case under new ownership by a public benefit entity. As noted above, grid defection fails to align stakeholder interests and would be the poorest of all the alternatives in this regard.

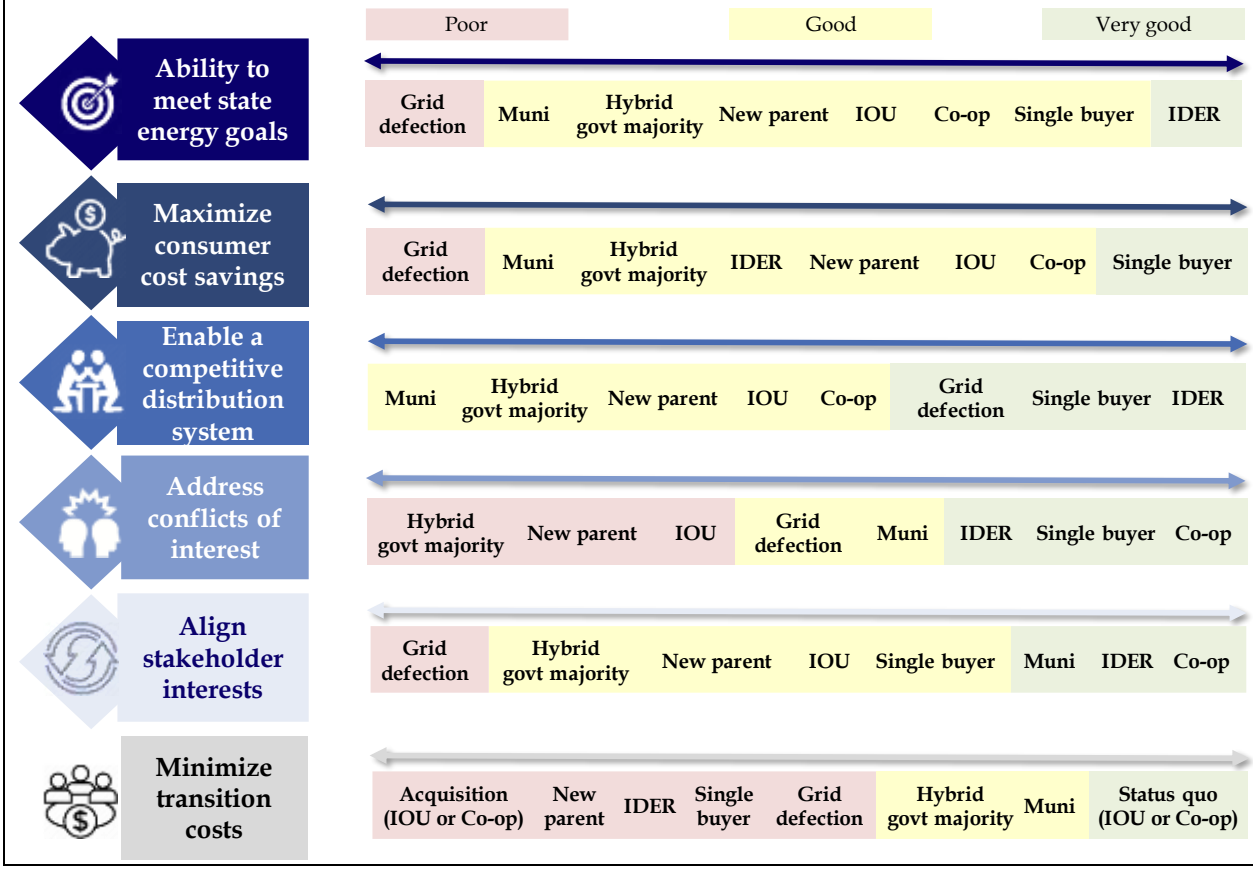
Assess transition costs

Assessing transition costs is explicitly called out as a major criterion as it acknowledges that there is an existing model that is being transitioned from. As a major criterion, it is fundamental to assessing the total cost impact to ratepayers. While arguably embedded in consumer cost savings, it is important to note that the various ownership structures differ substantially in transition costs. Depending on how entrenched the opposition from the utility, any transition may be subject to delay and litigation. The Status Quo (or IOU) would provide the lowest transaction costs while the grid defection would provide the highest transaction costs due to potential stranded costs. A cordial negotiated solution would minimize transition costs, even in those more complex solutions such as the IDER and ISO. One possibility to reduce transition costs could be a phased approach, for example, one in which the utility serves as the SB while an IDER ISO is being established.

Summary evaluation of ownership models relative to the criteria

The Project Team then performed a qualitative evaluation of the eight ownership models with respect to each of the six ranking criteria defined previously, assessing how each potential ownership model would help achieve the state policy objectives. The high-level results of this assessment are presented in Figure 19. Task 1.2.1 *(Comparison of ownership models)* includes the full discussion leading to the Project Team's evaluation of the ownership models with respect to the evaluation criteria.

Figure 19. Evaluation of ownership models relative to the ranking criteria



4.5 Feasibility of the ownership models

As mentioned earlier, one of the high-level assessments looked at the technical, financial, and legal feasibility of each ownership model.[87] Feasibility generally is defined as "the possibility that can be made, done, or achieved, or is reasonable."[88] These standards draw heavily from available literature and the guidelines of the PUC.[89] Figure 20 represents a summary matrix of the technical, financial, and legal feasibility of each ownership model.

[87] Detailed engineering, financial, or legal feasibility studies were outside the scope of this high-level analysis.

[88] Cambridge Dictionary. For comparison, Merriam-Webster defines feasibility as "capable of being done or carried out;" and Oxford Dictionaries defines it as "the state or degree of being easily or conveniently done."

[89] These include standards of review for utility acquisitions and changes in ownership models in the cases of (1) the acquisition of Kauai Electric by the Kauai Island Utility Cooperative and (2) the proposed acquisition of the HECO Companies by NextEra Energy; standards for electricity service as outlined in General Order No. 7 by the PUC; the performance metrics for electric utilities as outlined by the PUC; the responsibilities of the PUC as specified under Hawaii Revised Statute, particularly Title 15 "Transportation and Utilities," Chapter 269 "Public Utilities Commission"; and the "Inclinations" of the PUC for the clean energy vision of Hawaii as outlined in "Exhibit A: Commission's Inclinations on the Future of Hawaii's Electric Utilities.

Figure 20. Summary matrix of the technical, financial, and legal feasibility of each ownership model

<table>
<tr><th>Model</th><th>Comply with reliability, adequacy, quality of service?</th><th>Require separation of some businesses?</th><th>Require costs to move to new model?</th><th>Require legal or regulatory changes?</th></tr>
<tr><td>1) Status Quo (IOU or co-op)[1]</td><td rowspan="7">Yes</td><td rowspan="5">No</td><td colspan="2">No</td></tr>
<tr><td>2) Owner change (IOU or co-op)[2]</td><td rowspan="5">Yes</td><td rowspan="2">No</td></tr>
<tr><td>3) New parent</td></tr>
<tr><td>4) Muni</td><td rowspan="4">Yes</td></tr>
<tr><td>5) Hybrid</td></tr>
<tr><td>6) IDER</td><td rowspan="2">Yes</td></tr>
<tr><td>7) Single Buyer</td></tr>
<tr><td>8) Grid defection</td><td colspan="4">No</td></tr>
</table>

Note: (1) IOU in Hawaii, Maui and Honolulu Counties; co-op in Kauai County (2) Change from IOU to co-op in Hawaii, Maui, and Honolulu Counties; Change from co-op to IOU in Kauai County.

Based on the analyses, all the models, except for grid defection, can theoretically meet the PUC standards for utility responsibilities. However, most utility models would also require additional hiring and workforce considerations, in part because of civil service restrictions or collective bargaining requirements (e.g., muni and potentially hybrid ownership models), and management or salary concerns (e.g., co-op, or to establish capacities or expertise in new areas such as the IDER and SB models).

In terms of financial feasibility, a friendly acquisition is potentially a necessary condition for the feasibility of the transition for a new owner, muni, hybrid (majority government ownership), and co-op models. While a "hostile" acquisition could be managed, this is likely to significantly escalate acquisition and transaction costs that the buyer will attempt to pass onto consumers. For the IDER and SB models, the costs required to set up these models would vary depending on the mechanisms under each model.

Lastly, legal or regulatory changes are needed to allow for the establishment of independent IDER and SB entities. For the muni, legislative action is needed at a minimum and requires either a local referendum, county council action, or state action on municipalization. The succeeding subsections discuss the different feasibility aspects of the ownership models.

4.5.1 Technical feasibility

Technical feasibility evaluates whether the ownership model in question enhances or detracts from the utility's ability to carry out its roles and responsibilities for the State, including its ability to contribute to the achievement of state energy goals. The PUC has identified the roles of an electric utility in various regulations and laws. These include providing adequate and reliable energy supply, avoiding interruption of services, complying with standards set by the PUC, and maintaining service quality, to name a few.

Based on the high-level assessment, all the models—except for grid defection—can theoretically allow utilities to meet their responsibilities as set by the PUC. Moreover, for most of the ownership models, the role of the utility is unchanged in generation, transmission, and distribution, with the assumption that current regulations remain unchanged. Exceptions to this rule are the SB and the IDER models, which require the separation of some of the business entities that are currently within the utilities. For the IDER model, there might be a need to separate the generation business. For the SB model, the procurement division of the utility would need to be separated from the utility, either through ring-fencing mechanisms (for the SB within the utility) or as a stand-alone entity (for the SB outside the utility).

4.5.2 Financial feasibility

Financial feasibility evaluates the financial characteristics of the ownership model, including whether it is possible (from a financial perspective) to implement the ownership model and what financial benefits or costs would accrue to ratepayers.

One potential upside of a new IOU owner (under the new parent model) by being investor-owned, is that it may have broad access to capital markets. However, this access to capital markets does not necessarily entail lower costs of capital, since the cost of capital can vary according to market conditions, the nature of the asset, and the characteristics of the acquiring entity. Nor is it necessarily guaranteed that broad access to capital is unique to an IOU owner. Another potential upside is that the merger or acquisition improves the finances of the HECO Companies, allowing them to borrow at a lower cost. Such improvements in credit ratings and access to capital also depend on the nature of the acquiring company. If achieved, credit improvements could entail the procurement of improvements and infrastructure in a more cost-effective manner, since the cost of debt for such projects would be lower. Overall, while there are many possible benefits of a new IOU owner, these financial benefits are not intrinsic to the IOU model and rely on additional characteristics, including the nature of the proposed transaction, characteristics of the acquiring entity, or PUC enforcement of its guidelines for ownership transitions, among others.

Under the Hybrid with majority government-owned model, a significant up-front investment is involved in acquiring the majority share of the company. It could be assumed that the Hawaii state government would most likely purchase the majority share of utilities through bond issuance under this ownership model. However, it may potentially allow for a longer-term lower cost of capital if investors view the government as absorbing some of the risks of the business. Currently, such a purchase may initially increase the overall debt of the State of Hawaii; the long-term impacts are uncertain. In terms of initial feasibility, it should be noted that Hawaii has an optimal credit rating, with a credit score AA1 from Moody's, AA+ from S&P Global, and an AA

rating from Fitch as of May 2017.[90] This implies that there is room for the Hawaii government to undertake debt at a reasonable cost. Financial feasibility under the Hybrid ownership model is subject to the transaction, limits on bond issuance, and government management.

The acquisition cost by a muni would depend on the nature of the acquisition and any negotiations or proceedings that would accompany the purchase. Munis have access to tax-exempt capital for improvements following the initial acquisition, which remains taxed. This can help ensure the cost-effectiveness of improvements made to achieve Hawaii's clean energy vision. However, there are limits on a town's bonding authority, subject to the credit of the municipalities in question, the cost of servicing such debt, and other legal limits of bond issuance. If the county governments seek to municipalize, most have positive credit ratings, either as Aa1 or Aa2, for their general obligation bonds.[91] This means that county credit ratings could potentially support an acquisition. However, the county governments will have to consider whether they would be willing to make the long-term financial commitment to buy the county operations and infrastructure of their utility.

The Hawaii state and municipal governments generally have strong credit ratings to undertake the debt required to acquire assets at a relatively lower cost. However, there are limits on municipal bond issuance while the expenditures would be quite substantial in all cases, whether it is a hybrid or a municipal model. Munis can also take advantage of tax-exempt bonds—which can potentially be lower than market-based rates—due to their association with a municipality.

Co-ops often have access to low-interest financing, which allows them to purchase assets at lower costs for their members. In terms of the initial acquisition, members could contribute equity to the purchase of the utility assets, and the transaction is not significantly different from any other entity that seeks to purchase utility assets. In lieu of equity, the co-op could assume ownership by leveraging high amounts of debt, which is a more likely pathway for cooperative acquisition. The cost of such debt can vary but is generally between 1% and 5%.[92] However, by relying primarily on debt for the purchase of utility assets, a cooperative utility may have difficulty in limiting rate increases during the repayment period. But, even if co-op members are unable to contribute significant amounts of equity to the utility and subsequent improvements, co-op members have access to low-cost financing through both federal and cooperative lending sources. The USDA RUS, for example, has specific loan programs to support energy efficiency and renewables, and additional grant programs specifically for high-cost energy areas.[93] Other dedicated cooperative lenders, such as CoBank and the Cooperative Finance Association, also

[90] The Pew Charitable Trusts. "Rainy Day Funds and State Credit Ratings." May 2017. <http://www.pewtrusts.org/~/media/assets/2017/05/statesfiscalhealth_creditratingsreport.pdf>

[91] Moody's. Ratings of GO Bonds for Hawai'i (Aa2), Kauai (Aa2), Maui (Aa1), Honolulu (Aa1).

[92] See Kauai Island Utility Cooperative. "Consolidated Financial Statements, December 31, 2016 and 2015." Note 8-Long-term Debt. Page 17. <http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/financials/2016%20Audited%20Financial%20Statements.pdf>

[93] Cowan, Tadlock. "An Overview of USDA Rural Development Programs." Congressional Research Service, February 10, 2016. <http://nationalaglawcenter.org/wp-content/uploads/assets/crs/RL31837.pdf>

provide dedicated sources of financing to electric co-ops. Finally, even if the co-op cannot own and operate all the projects itself, it can also procure them from other entities. These financing mechanisms can help co-ops secure the financing for Hawaii's clean energy vision while dampening any increase in the rates of consumers.

There would be set up costs involved for the SB models. Under an SB where it is still part of the incumbent utility, set up costs would include a separate office for the SB, IT infrastructure, and other ring-fencing mechanisms to ensure that the SB is independent of the utility. Under an SB where it is outside of the utility, additional infrastructure investments need to be made. Although the final cost of establishing an SB is unclear due to its many variations, housing the SB within the incumbent utility might from a technical standpoint be less expensive due to the preexisting role that incumbent utilities already play in procuring generation from IPPs in Hawaii. If another entity undertakes that role, it would have to develop and acquire that expertise and need to invest in infrastructure to operate the SB.

Similar to the SB models, the IDER model entails set up costs to build the platform and the infrastructure needed for the customers, DER providers, and other market participants to transact. In New York State, some pilot programs on IDER have been implemented. One of these programs is the Buffalo Niagara Medical Campus DSP Engagement Tool where the hospital campus is used as a testbed for the distributed system platform ("DSP") functionalities and used to coordinate and optimize the DERs throughout the campus. This pilot program's capital expenditure was $4.4 million, and the costs of the operation are $385,000 for less than a 3-year period.[94] Nevertheless, it is difficult to assess the overall financial outlook for the IDER model due to insufficient data. Ideally, the IDER model should be able to optimize value streams and deliver such benefits to ratepayers through an efficient and competitive marketplace. In doing so, it could achieve the State's clean energy goals at market-based prices. However, the cost to establish the institutions to govern this market could be considerable.

In summary, while utilities generally are open to acquisition with a sufficiently high purchase price, higher acquisition costs would likely result to increase in electricity rates. The willingness of the incumbent utility to sell its assets plays an essential role in determining the acquisition cost when transitioning to a new owner, be it be another IOU, a muni, a co-op, or another government vehicle. For IDER and SB models, set up costs could be sizable, depending on the mechanisms that are required to operate these models.

4.5.3 Legal feasibility

Legal feasibility assesses whether the transition to another ownership model is possible given current laws, statutes, and regulations.

The shift to new IOU owner and co-op models (assuming the co-op would be regulated to the same extent KIUC is currently regulated) would not require new legislation or regulation because a prior legal framework is already in place. However, the new IOU owner would have to pass

[94] National Grid. Distributed System Platform REV Demonstration Project Q2 2017. <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BFF2D4106-57EE-469A-A32C-201ABAFB1BE2%7D>

the scrutiny of the PUC and obtain its approval for a transfer of control. Grid defection would also not need any legal changes; instead, high electricity prices and declining costs in solar and storage would incentivize defection.

The muni model represents somewhat uncharted legal territory for Hawaii since municipalization has never been attempted. The muni model would, at a minimum, require either a local referendum, county council action, or state action on municipalization. Moreover, if municipalization is pursued against the wishes of the incumbent IOUs, legal questions may arise regarding the intersection between the county's eminent domain powers and the PUC's right under state law to approve or deny the disposition of utility assets. These questions would need to be resolved by the courts, PUC, and/or state legislation.

For the Hybrid with majority government ownership model, legislative action at the State level would be necessary to establish a holding company and allocate funding for the purchase of a majority of shares of the utility. However, such a takeover of a private utility that is financially solvent would be largely unprecedented in the United States.

For the IDER and the SB models, the PUC and/or legislature would likely need to make significant legal changes to establish the IDER model or have a separate and independent[95] SB. The specific type of action varies significantly depending on the particular model pursued. Legislative action may be necessary for the IDER model to establish an entity that can monitor and develop the market for DERs. The IDER model would also require several novel approaches, for example creating new value streams for DERs, or changing rate setting methodologies to incentive utility innovation, among others. The SB and the IDER models would require some form of separation between/among generation, transmission, and distribution assets.

Task 1.3.1 *(Identification of various steps, timeline, and costs)* discusses in detail the indicative steps, timeline, and costs necessary to change from the current ownership model to the new models.

4.6 Infrastructure needs with the change in the ownership model

Changing the ownership model of utilities in the State would not change the infrastructure required to achieve the State's energy goals (especially in grid modernization technologies) significantly. More specifically, infrastructure requirements will not differ drastically, whether owned by an IOU, co-op, or muni. However, a grid defection scenario would likely result in substantial stranded assets. Currently, the incumbent utilities—HECO Companies and KIUC—already possess the necessary infrastructure to reliably operate the grid and have prepared long-term plans to ensure continued reliability while achieving the RPS targets. Moreover, the roles and responsibilities of the electric infrastructure owners under the new ownership model would be the same as they are currently.

[95] Independent can either be (i) independent of the other business entities within the HECO Companies or the KIUC (such as generation division, transmission division, etc.) or (ii) independent of the entire HECO Companies or the KIUC.

On the other hand, the SB model would require new infrastructure investments initially upon its establishment, whether as a stand-alone entity or a ring-fenced unit within the existing utility. The checklist for establishing an SB under either variant of the model is mostly the same, but some of the technology and capability needed for more sophisticated resource planning may have to be replicated in both the SB and utility.[96] This outcome was observed in the case of Ontario Power Authority—an SB in Canada—which spent more than CAD $3.5 million (in 2005 dollars) in capex during its first year of operation. The investment covered costs of furniture, computer hardware and software, telephone system, and leasehold improvements.[97] The adoption of the model in Hawaii would likely require a lower investment cost because the office for the SB would be smaller, and the cost of technological improvements has been declining.

The incumbent vertically integrated utility must divest from its generation business and would only own the wires[98] assets under the IDER model. Therefore, the utility investments under an IDER model would be focused on advanced grid technologies, which had also been proposed by the HECO Companies. The IDER model would eventually allow peer-to-peer transactions across the distribution grid. For example, the IDER system operator, which could be the utility or an independent entity, would need to manage energy and payment flows among many different market participants. These types of market operations would require additional investments for the provision and protection of data as well as for ensuring a higher level of market participation from customers, DER providers, and other service providers. The Project Team reviewed the pilot programs and enabling technologies used in New York and observed that the infrastructure investments for the first five years of pilot projects range from $11 to $190 million.[99] The costs vary based on the technology, utility service area, and the current status of utility infrastructure.

To summarize, the review of ownership models indicated that only the SB and IDER models would require additional infrastructure and capability needs in the transition. The Status Quo (IOU), co-op, and grid defection models would not require additional infrastructure investments for the transition. Task 1.1.4 *(Assessment of future needs for generation, transmission, and distribution infrastructure)* provides a high-level discussion of the future infrastructure needs under each proposed utility ownership model.

4.7 Potential stranded costs

Stranded costs represent costs that a utility was allowed to recover through regulated rates but whose recovery may be impeded or prevented as a jurisdiction transitions from a regulated regime to a competitive, deregulated environment. Assets become stranded when a utility can no longer recover the costs incurred to acquire and operate them through the rate base. Historically,

[96] Detailed information on the steps in the setting up of a SB model, if chosen as one of the recommended utility ownership models, is discussed in Task 1.3.1. Identification of various steps, timeline, and costs required to change from current ownership model to new models, including regulatory approvals.

[97] Ontario Power Authority. *Ensuring Ontario's Electricity Future. Annual Report 2005.* March 2006. February 16, 2018.

[98] Wires assets include transmission and distribution assets.

[99] Tweed, Katherine. "Rate Base It! A Primer on New York's Distributed System Implementation Plans." Greentech Media. July 2016.

utilities have been allowed to recover their stranded costs provided that the investments were prudent and verifiable, as is typically expected if they had been subject to prior regulatory approval.

Due to the fact that each island operates an independent power grid, there are no existing alternative sources of power to those currently serving each county's load. Therefore, a change in ownership model of utilities would still require careful planning (and if necessary, additional investments) so that these assets would continue to ensure adequate supply and reliable transmission/distribution of power to customers.

Absent a change in the regulatory model that would introduce market-based constructs, all assets required to operate the power grid would remain in the rate base, or stay under contract with the new entity, which would then recover the contract costs from ratepayers. Therefore, a change in ownership model under the current regulated regime would not result in stranded costs, which must be recovered from ratepayers.

Figure 21. Summary table of potential stranded costs for each ownership model

<table>
<tr><th>Ownership model</th><th>Generation assets</th><th>Transmission and distribution assets</th></tr>
<tr><td>Traditional utility models:
• IOU (status quo or new owner)
• Muni
• Co-op
• Hybrid - majority government-owned</td><td>No stranded costs</td><td>T&D assets remain under regulated regime, hence no stranded costs are expected</td></tr>
<tr><td>IDER</td><td rowspan="2">Potential for stranded costs if generation asset have lower value under a new regulatory model than under current regulated regime</td><td rowspan="2">T&D assets remain under regulated regime, hence no stranded costs are expected</td></tr>
<tr><td>Single Buyer</td></tr>
<tr><td>Grid defection</td><td colspan="2">Technically no stranded costs would result as assets remain in rate base. However, there would be a growing number of assets no longer used and useful, resulting in growing costs being spread over a smaller and smaller group of customers</td></tr>
</table>

However, the IDER system operator and SB models would require a change in the regulatory structure so the framework that would govern market-based compensation of generation resources may be created. Therefore, there is a potential for stranded costs if generation assets under the new regulatory structure have a lower value. In general, thermal generation plants that are less than 30 years old are more likely to become stranded because they may retain a useful accounting life beyond when they are made obsolete by a 2045 100% renewable portfolio standard. In the case of the Hawaii utilities' thermal generation fleet, which is valued at approximately $1,200 million with about 400 MW of generation capacity that is less than 30 years in age,[100]a portion could potentially be a source of stranded costs under a change in ownership and regulatory structure to IDER system operator or SB. However, renewable generation is not

[100] Based on LEI's analysis of regulatory filings by the HECO Companies and KIUC.

expected to replace thermal generation overnight, so an asset would have likely recovered much of its book value by the time it is retired.[101] Task 1.1.6 *(Identification of estimated stranded costs for each ownership model)* discusses the potential stranded costs for each model in detail.

4.8 Views from stakeholders

The community outreach for the utility ownership models was conducted between October 9, 2017 and October 13, 2017 on the islands listed in the textbox on the right. The Project Team notes that the survey of the public was not a statistically representative sampling of the population but was intended to be illustrative of a range of views.

Location of the Community Outreaches

- City and County of Honolulu
  - Honolulu
  - Waialua
- Hawaii County
  - Hilo
  - Kona
- Maui County
  - Lanai City, Lanai
  - Wailuku, Maui
  - Kaunakakai, Molokai
- Kauai County
  - Lihue

The objectives of the workshops were to provide stakeholders with information from the preliminary analysis of the ownership models, to receive their input on what they value in their utility, and input on the advantages and disadvantages of different ownership models in meeting those values. Combined, 141 stakeholders participated in the public workshops.

In addition to the workshops, the Project Team conducted multiple bilateral meetings as part of the ongoing stakeholder engagement process throughout the entirety of this project. The Project Team met with 20 energy industry, government, and other stakeholders from across the state. Input varied from the importance of leadership (of both the utility and the Hawaii Public Utilities Commission) to the technological opportunities for addressing specific needs (e.g., microgrids and resiliency), to the value of local influence on decisions, to the need for innovation and nimbleness to address the state's needs.

Throughout the process, stakeholders who participated in the community outreaches repeatedly raised concerns on the current high electricity rates. They also mentioned the ability of the stakeholders to be engaged in and influence utility decisions to ensure they are aligned with community needs; demand for more renewable energy, from more diverse sources, and for more opportunity for customer-sited generation; and enabling competition to improve efficiency, to name a few.

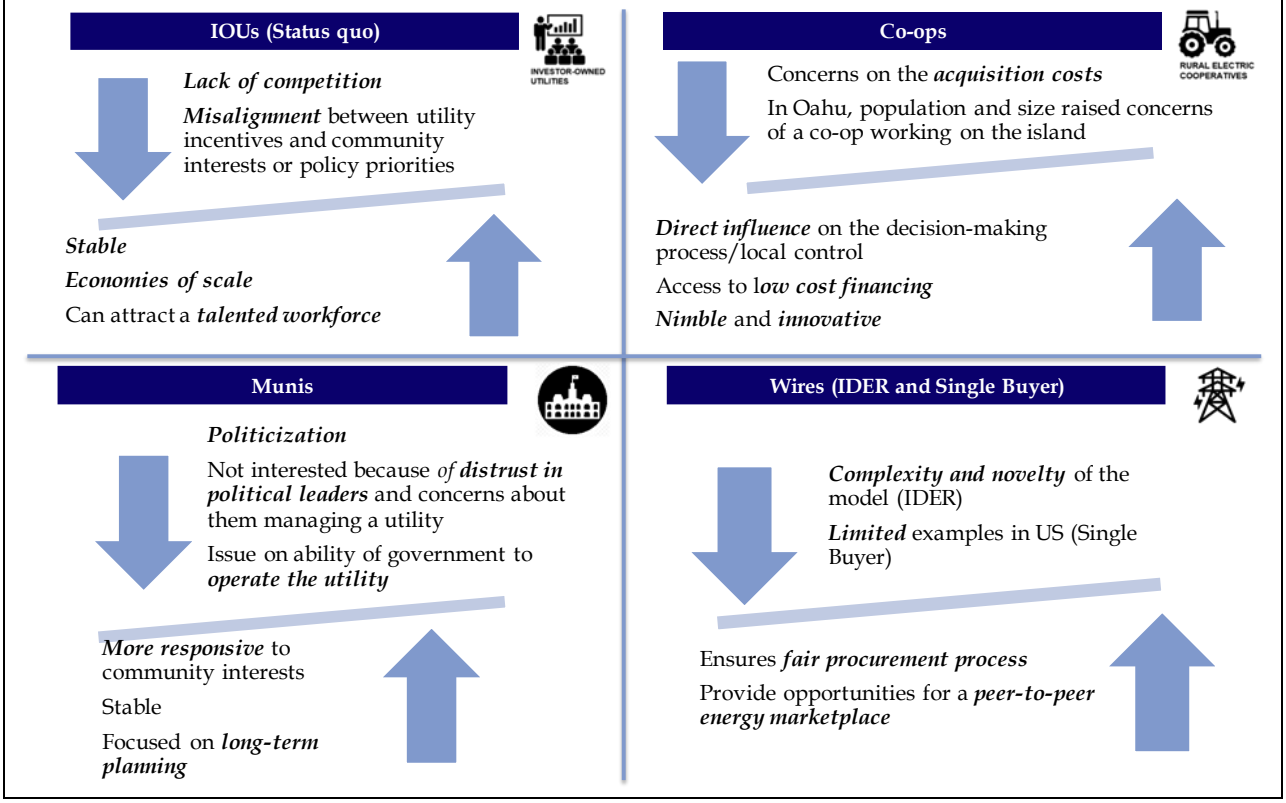
The participants also provided their views on the different ownership models. In general, participants in the community outreaches expressed that IOUs were typically stable, benefitted from economies of scale, and could attract a talented workforce. There was a concern, however, about a lack of competition and a misalignment between utility incentives and community or policy priorities. Stakeholders often expressed concern that they see IOUs as driven primarily by increasing shareholder profit and that they do not view IOUs as innovative in adopting new technologies. Some stakeholders were interested in how what they saw as a misalignment of

[101] The annual straight-line remaining-life depreciation rates vary by generation asset accounts but average approximately 2%.

interests could be addressed through regulatory approaches, or the adoption of new investor-owned utility models, such as B-corp.

While stakeholders who participated in the outreach meetings liked that the muni model allows for community members to have a more direct influence on utility decisions, many stakeholders were concerned about the potential for political influence to hinder utility operations. Additionally, many expressed concerns that the government would not operate the utility efficiently. With the exception of a few stakeholders, there was little interest in this model.

Figure 22. Pros and cons of the different ownership models according to participants to the community outreach meetings



On the other hand, many stakeholders during the stakeholder outreach meetings agreed that the primary benefit of the co-op model is the ability that consumers have to impact utility decisions directly. Many pointed to KIUC as a successful example of the co-op model and, based on that example, the potential that this model has for providing lower rates. A number of stakeholders mentioned that this model works best with educated, engaged members, and there are difficulties in achieving this. The interest in the co-op model varied by island, with more interest expressed on Kauai and the Big Island (particularly at the Hilo meetings). Some stakeholders at the meetings on Oahu (both Waialua and Honolulu) and Maui were not sure that this model would work on their respective islands due to population size, geographical diversity, and concerns about qualifying for rural financing programs.

The wires-only models, which include the SB and the IDER models, were discussed in detail during the workshops in Honolulu, Kona, Wailuku, and Waialua. The stakeholders felt that a primary benefit of this model is its potential for encouraging competition in generation and that this could result in lower rates. Nevertheless, the participants recognized the novelty of the concept and that there are limited examples to learn from. Figure 22 summarizes the pros and cons based on the comments of the participants.

In general discussions, some participants in the community outreaches felt that a change in ownership model might not address their community's priorities and expressed interest in understanding how regulatory changes could incentivize utilities to align their actions with community goals. When discussing a theoretical change in ownership, many stakeholders highlighted that the transition costs would be too high to bear without a willing seller. Task 1.2.4 *(Outreach Plan and documentation of results of public outreach)* provides an additional discussion on stakeholder views regarding utility ownership models.

4.9 Ownership models selected for further study

Taking into account the Study's legislative goals, inputs from the stakeholders, results of the high-level assessments, and the State's unique characteristics and challenges, the IOU, co-op, and SB models (within and outside of the utility) are the most beneficial utility ownership models among the eight models for further review. Notably, the IOU model on all islands except Kauai, and co-op model on Kauai represented the baseline against which the alternative models were compared.

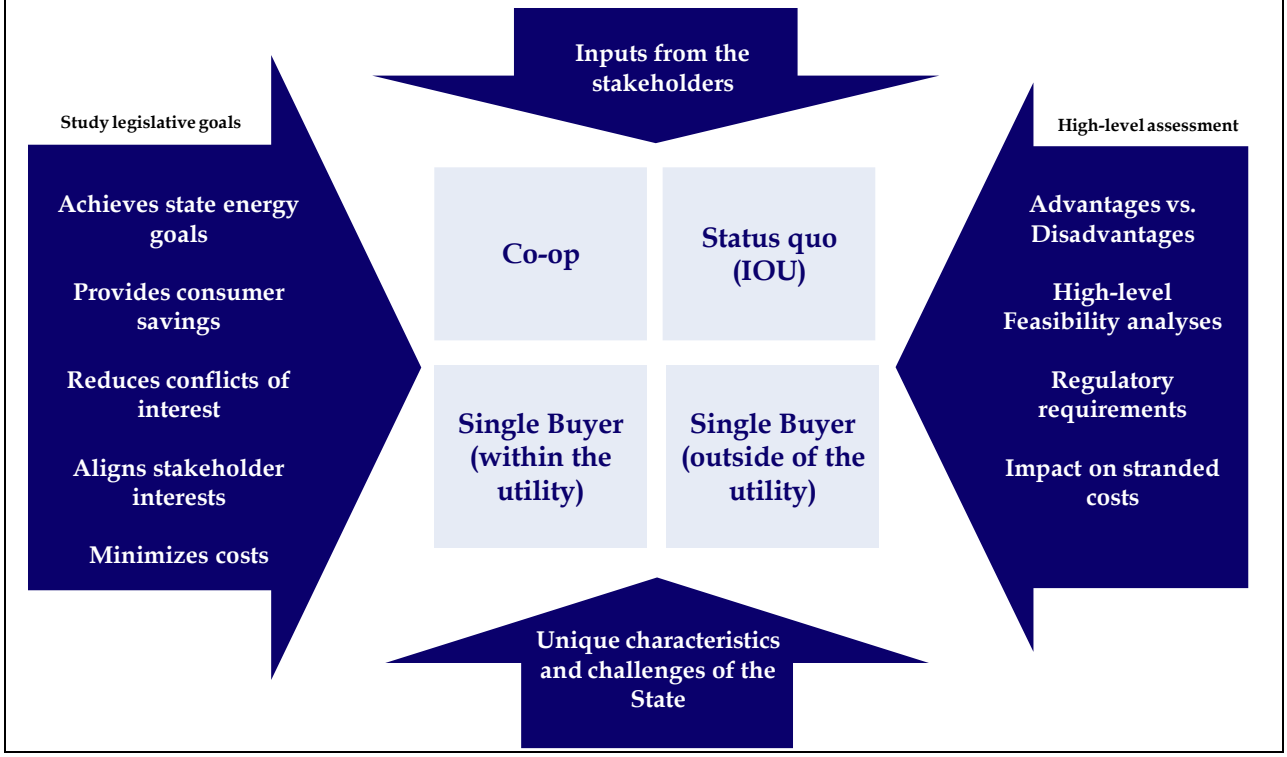
Reflecting on the establishment of KIUC, many stakeholders have expressed support for the establishment of a similar co-op system in each of the islands. Compared with an IOU, the co-op model is perceived to lead to the stronger alignment of stakeholder interests because the consumers in this model are also the owners. Moreover, it eliminates or at least lessens the profit motive that is more inherent in IOUs. Furthermore, the co-op has access to lower cost debt financing insofar as the typical market rate for utilities is applied. However, a transition to the co-op model beyond Kauai would likely require a significant debt-based purchase from the incumbent utility, which may have long-term impacts on ratepayers. Moreover, co-op leaders are elected by members, so the competence of managers would depend on the outcome of these elections.

The SB model outside of the utility ranks highly because of its significant role in addressing several perceived deficiencies with the IOU model (such as conflict of interest within utility operations, the fair conduct of the procurement process, independent energy, and capacity planning). At a high level, the SB entity in this model is expected to procure energy for the long term at the least cost, which is likely to create consumer cost savings and facilitate competition for power supply contracts.

Similar to the "outside" SB model, the SB model inside the utility generated a high score because it can address perceived deficiencies of the IOU model (such as conflicts of interest within utility operations and the fairness of procurement and planning processes). Its main responsibility is also focused on procuring energy at the least cost. Unlike in the "outside" SB, the SB here can draw from existing utility staff and expertise more readily. The grid defection, hybrid ownership (with a majority government stake), and traditional IOU under a new owner model generated the

lowest scores. They were judged to be least effective in supporting the State policy goals and preventing rate volatility. Task 1.2.5 *(Ranking process and rationale for the recommendation of three feasible utility ownership models)* discusses the methodology and results in detail.

Figure 23. Utility ownership models selected for further analysis



4.10 Indicative timeline to transition to another model

4.10.1 Ownership transfer

The process of transferring ownership of utility assets, either IOU to co-op or co-op to IOU, is estimated to take between two to three years, based on the experience of KIUC and the U.S. Department of Agriculture ("USDA") as well as assumptions about the process going forward in Hawaii following KIUC's precedent. The acquisition process for KIUC took approximately three years,[102] but a future acquisition could be shorter because stakeholders have learned from KIUC's experience.

For a co-op specifically, there is increased familiarity with the co-op model among the local population, and the public perceives KIUC as a successful utility. The USDA notes that the

[102] KIUC was officially formed in November 1999 to purchase Kauai Electric from Citizens Communications. In 2000, the PUC denied the acquisition of Kauai Electric by KIUC, prompting a subsequent renegotiation and regulatory proceeding in 2002 that culminated in the approval of the acquisition. The final acquisition occurred on November 1, 2002. This suggests that a timeline for subsequent acquisitions by prospective co-ops could be shortened through sufficient preparation for regulatory proceedings.

process for the formation of a co-op can take up to two years.[103] The process for setting up a co-op involves four key phases, namely: (i) establishment; (ii) purchase; (iii) regulatory approval; and (iv) subsequent operation. Figure 24 summarizes the key steps in the establishment of a co-op ownership structure.

Figure 24. Key steps in the establishment of a co-op

Steps		Timeline (months from start)
Phase 1	Establishment	1 - 6
	Initial Leadership and Stakeholder Discussion	1 - 2
	Formation of Provisional Committee	1 - 2
	Survey of Local Population	2 - 3
	Formationg of Steering Committee	2 - 3
	Incorporation and Bylaws	3 - 5
	Membership Recruitment Campaign	3 - 5
	Founding Assembly and Board Election	6
Phase 2	Purchase	3 - 24
	Feasibility Study and Financial Analysis	3 - 5
	Fund, Negotiate, Purchase Assets	6 - 24
Phase 3	Regulatory Approval	3 - 24
	Legal Outreach	3 - 24
	Regulatory Approval	13 - 24
Phase 4	Operation	25 - 28
	Transition of Workforce	25 - 28
	Commence Operations	28

4.10.2 Single Buyer

The formation of the SB could take between two and five years, with significant variability based on intervening factors, such as the contentiousness of legislative and PUC actions. The SB model carries some measure of uncertainty when it comes to the steps required for its establishment. Some result from the lack of existing empirical data from which Hawaii could learn from, as there are limited examples to draw from in the United States. The Project Team assumed in this case that the incumbent utility would be an IOU and that the SB would take over the functions of procurement (of all new generation capacity additions) and system planning, but not grid operation or dispatch. Based on the experiences of the Ontario Power Authority for a SB model outside of the utility and TNB in Malaysia for an SB model within the utility, as well as knowledge of the timelines required for the legislative and regulatory process in Hawaii, the timeline of 3-5 years is estimated for the establishment of a SB model, although the timeframe for the SB within the utility would be shorter. Figure 25 shows the indicative steps required to transition toward an SB model from the Status Quo. Task 1.3.1 *(Identification of various steps, timeline, and costs)* provides a more detailed discussion on the steps and timeline of the co-op and SB models.

[103] U.S. Department of Agriculture. "How to Start a Cooperative." Presentation slides. No date cited. <https://www.rd.usda.gov/files/publications/How%20to%20Start%20a%20Co-op.pdf>

Figure 25. Key steps in the establishment of an SB within the utility

Steps		Timeline (months from start)
Phase 1	Preliminary Discussions and Analysis	1 - 3
	Initial Leadership and Stakeholder Discussion	1 - 3
Phase 2	Establishment	4 - 36
	Legislative Enactment	4 - 12
	PUC Proceedings	4 - 33
	Incorporate, Establish Bylaws, and Draft Rules	34 - 36
Phase 3	Operation	37 - 42
	Staff the Single Buyer	37 - 42
	Organizational and Operational Transformation	37 - 42
	Establish and Refine Planning Process	37 - 42
	Commence Operations	42

4.11 Required legal changes

Co-ops and IOUs are legally feasible utility ownership models in the state, and a regulatory change is not necessary for either establishment. Nevertheless, in order to develop a co-op, the organization would need to demonstrate that it has undertaken the appropriate steps, due diligence, and preparation for its establishment (e.g., in terms of achieving nonprofit status, compliance with tax laws and state regulations that define co-ops, etc.) and subsequent planning so it can meet the standards outlined by the PUC for transferring, owning, and operating utility assets. A new IOU would similarly need to meet those standards. Indeed, the PUC still needs to approve the transaction whereby the new owner (co-op or IOU) acquires the assets from the incumbent utility.

For a co-op, the necessary legal or regulatory frameworks that could help ensure its viability and overcome potential barriers already exist. For example, co-ops seeking to serve non-rural communities—particularly in urban environments of Maui, Oahu, and the Big Island—may find it difficult to raise the capital (for the purchase and transfer of ownership of utility assets) from traditional lenders such as RUS. Faced with this hurdle, policymakers could help in reducing this burden (e.g., drawing on the preexisting legislative authority of HRS § 39A-191, which further provides special purpose revenue bond support to aspiring co-ops). Additional regulatory measures could be crafted to help reduce the risks of utility ownership, thus, lowering the cost of capital for such endeavors. Nevertheless, it may be advisable to seek legislation that would specify and clarify how and to what extent the newly formed co-op, as a public utility, should be regulated by the PUC.

Finally, prospective owners should be aware that prior mergers and acquisitions proceedings do not constitute a legal precedent. Regardless, lessons can be drawn from the guidance of the PUC provided in the Appendix of the NextEra *Decision and Order* in presenting their case for approval. There is no *de facto* reason why a co-op would be unable to meet the standards outlined. Some of the standards likely bear little relevance to the case of the co-op and, in some cases, the co-op outperforms the standards outlined in that Decision and Order (e.g., reflecting local community stakeholder input). Additional risks, including possible mitigation measures that may impact

these standards, are outlined more thoroughly in Task 1.3.3 *(Identification of risk for each ownership model, analysis of each risk, and assessment of the overall risk profile for each ownership option).*

Likewise, the transition to an SB within the utility model may not require enabling legislation. In such a scenario, the utility would be performing responsibilities that are similar to those that it had been performing before (considering that the SB is only performing procurement and planning). The key difference is that the ring-fencing further segregates the personnel and assets that are implementing these core responsibilities from the other activities of the utility. Moreover, since the utility would continue to house the key functions of procurement, it arguably still maintains its privileges under the franchise agreement, albeit with more stringent guidelines. Both processes—procurement and planning— have precedent in previous PUC guidance and action. It is possible that the PUC may shape the utilities' procurement and planning functions further towards an SB model without legislative action. However, without legislative action, the PUC is not required to take the initiative in implementing the SB model, and it is possible that the PUC may not take action if there is no mandate—even with legislative action.[104] Therefore, the establishment of the SB within the utility model would be legally feasible, and there is significant latitude over how the initial studies and eventual establishment could occur if pursued.

In contrast, the establishment of an SB outside the utility would almost certainly require enabling legislation, because it would need to be created by a governmental agency or be contracted by a public agency. Additionally, an "outside" SB would likely not be considered subject to PUC regulation as a public utility because it would sell all of the electricity it purchases directly to HECO for transmission or distribution to the public. State statutes provide that an entity that sells all its electricity (except that used for its own consumption) directly to a public utility for transmission or distribution are precluded from being considered a public utility.[105,106] Because the PUC's authority and general investigative power are limited to public utilities, an express grant of jurisdiction or responsibility would be required to confer the PUC with the power to regulate the "outside" SB. Without such legislation, the PUC's ability to regulate the SB outside of the utility would be limited to regulating utilities' transactions with the outside SB.

Task 1.3.2 *(Identification of legal changes needed to implement the proposed utility legal framework options*) provides a more detailed discussion on the legal feasibility of these ownership models.

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[104] See, e.g., Act 166 (2012), in which the legislature authorized, but did not require, the PUC to contract with a Hawaii Electricity Reliability Administrator ("HERA") to develop and implement local reliability standards and interconnection requirements with accompanying enforcement in a manner comparable to the role filled on the mainland by the North American Electric Reliability Corporation and the regional oversight entities. See Act 166, S.L.H. 2012 § 1 Act 166, S.L.H. 2012 § 1; HRS Chapter 269, Part IX.

[105] HRS 269-1 and HRS 269-141.

[106] HERA is distinct from the "outside" SB because it is legislatively authorized and would consist of an entity that the PUC would contract with to carry out reliability functions (adopt and regulate interconnection standards) that the PUC normally does itself and would be subject to PUC regulation.

4.12 Potential costs related to a transfer in ownership of utility assets

Any transaction involving a change in the ownership of utility assets, be it from IOU to co-op or co-op to IOU, involves costs. Such a transition could also result in a change in the approach used to calculate the utility's revenue requirement. For instance, the revenue requirement for an IOU is calculated through a rate of return COS approach, while the TIER approach is used for co-ops. The transition would also change some upfront or non-recurring costs and recurring costs.

In the case of a co-op, the cost estimates for its creation (which include stakeholder outreach, cost-benefit analyses, incorporation, and regulatory approval) and transition of current IOU staff are based on the expected timelines and level of engagement required. The acquisition cost estimates are derived from the results of a comparable transactions analysis that the Project Team conducted. For those interested in understanding the detailed assumptions underlying these cost assumptions, Task 1.4.2 *(Identification of legal changes needed to implement the proposed utility legal framework options)* summarizes the approach in estimating these costs, with additional details in Tasks 1.3.1 (*Identification of various steps, timeline, and costs*).

The estimated upfront costs, which refer to the initial expenses to operationalize the co-op, include establishing a co-op, purchasing the assets from the incumbent utility, and transitioning current staff and operations to a co-op model. These costs are summarized in the table below.

Figure 26. Indicative acquisition and transition costs to a co-op model

	HECO	HELCO	MECO
Acquisition cost – purchase price	$3.25 billion	$0.76 billion	$0.65 billion
Establish a co-op	$2.3 – $3.3 million		
Transition and training of current utility staff	$0.25 million		

Source: LEI analysis. The Project Team evaluated nine previous acquisitions involving comparable utilities and analyzed the Enterprise Value; Equity Value; Earnings Before Interest, Taxes, and Depreciation ("EBITDA"); and Net Incomes of the acquired utilities. The numbers in the table above were calculated by averaging the valuations estimated using Enterprise Value/EBITDA and Equity Value/Net Income comparisons.

Under the co-op model, the reductions in utility expenses would help in part offset the upfront costs. These utility expenses include interest, income tax, and, potentially, regulatory expenses. The co-op could secure subsidized debt to finance the acquisition costs upfront, but the ratepayers bear the costs of servicing this debt over time. With the TIER-based ratemaking approach, capital costs for a co-op include the interest expense on its debt as well as the required interest coverage. As members accrue equity in the form of patronage capital retained by the co-op, capital costs decline relative to an IOU.

Co-ops also offer immediate and concrete savings from avoided federal income tax expenses. Since co-ops are tax-exempt at a federal level, they are only required to pay state income taxes. Compared to their 2016 tax liabilities as IOUs, the HECO Companies would have seen an estimated $41 million reduction in tax expense if they were co-ops and exempt from federal income taxes. Figure 27 shows the breakdown of these savings.

There may be other potential opportunities to lower costs under a co-op model that have not been included in the quantitative modeling; these are discussed in more detail in Task 1.6.1 *(Overview of the differences in how revenue requirement is calculated under each ownership model)*. Replacing the current utility management structure to nimbler, and potentially more efficient, co-op entities could potentially lower certain overhead expenses related for instance to administration or IT infrastructure. A co-op may also be eligible for disaster relief assistance from the Federal Emergency Management Agency ("FEMA"). This means that the co-op would not pass on to the ratepayers the entire cost of recovery from natural disasters like hurricanes and volcanic activity to which Hawaii is vulnerable. Therefore, moving towards a co-op model on any island or county in Hawaii comes with a trade-off between a lighter and efficient structure for co-ops vs. economies of scale for the current IOU structure.

Task 1.4.2 *(Economic evaluation of ownership and operation of each ownership model)* discusses this in more detail.

Figure 27. Illustrative – estimated savings from federal tax exemption based on 2016 tax liabilities

($000s)	IOU	Co-op	Savings
35% Federal Tax Rate			
HECO	57,442	8,880	48,562
MECO	12,464	1,927	10,538
HELCO	11,673	1,804	9,868
HECO Companies Total	**81,579**	**12,611**	**68,968**
21% Federal Tax Rate	ILLUSTRATIVE ONLY		
HECO	38,017	8,880	29,137
MECO	8,249	1,927	6,323
HELCO	7,725	1,804	5,921
HECO Companies Total	**53,991**	**12,611**	**41,381**

Source: SNL; HECO-3203, DOCKET NO. 2016-0328.

Likewise, a move to any of the two SB models would require initial capex to set up the SB entity with the necessary infrastructure and operating costs. A transition to the SB model within the utility involves implementing ring-fencing mechanisms such as setting up separate work areas and information technology systems for the SB and additional security protocols for highly sensitive and confidential information relating to the SB's functions, to name a few. Also, some resources, such as human resources, legal, and accounting, would still be shared with the parent utility, under the SB within the utility. On the other hand, the SB model outside of the utility would incur additional expenses such as conducting annual audits and hiring of personnel that would typically have been shared with the parent company.

It is projected that the transition costs to set up an SB range from $2.3 million to $3.3 million – this includes the costs of stakeholder outreach and regulatory or legislative processes but does not include acquisition costs for a co-op or the capex to establish the SB offices.[107] This estimate is

[107] The transition costs for a co-op were informed by NRECA's technical assistance guides on the creation of co-ops.

based on the steps required, timeline, and projected costs of each step as summarized in Figure 25 and described in detail in Task 1.3.1 *(Identification of various steps, timeline, and).* An SB would incur its own operating expenses for system planning and procuring power from IPPs. It requires separate business premises from the rest of the utility, which necessitates additional rental costs for appropriate office space.

It is assumed that the transfer of some of the utility's responsibilities to an SB would lower the parent utility's current expenses for the planning department by half. The utility would continue to perform its own planning, and the costs related to this would be included in the utility's revenue requirements and passed on to ratepayers. Although the SB does collect fees to cover its operating costs, including from the IOU, these costs are ultimately passed on to ratepayers.

The primary benefit of an SB is a more level playing field between utilities and IPPs. It is assumed that the SB's independence in both planning and solicitations for power supply would lower purchased power costs by 3%. The 3% is based on the lower end of the range of efficiency gains found by several quantitative studies on the benefits of competition and unbundling. These studies are cited in more detail in Task 1.4.2 *(Economic evaluation of ownership and operation of each ownership model).*[108]

The upfront capital costs to set up an SB and ongoing annual operational expenses were estimated based on the reported costs of the Ontario Power Authority. The Project Team adjusted these costs for Hawaii to account for inflation and scale. These costs are summarized in Figure 28.

Figure 28. Estimated 2016 expenses under the SB model

($000s)	HECO	MECO	HELCO	KIUC
Initial Capex	3,140	514	913	257
SB outside the utility				
O&M	9,738	4,929	5,599	2,465
Office Rent	279	46	81	23
Audit	15	15	15	15
Total	10,032	4,990	5,695	2,502
Ring-fenced SB				
O&M	8,717	4,709	5,473	2,355
Office Rent	279	46	81	23
Incremental IOU earnings	238	38	71	0
Total	9,234	4,793	5,625	2,377

Source: LEI analysis.
Note: These numbers were initially estimated for a hypothetical SB if it had been operational in 2016 to evaluate potential savings. They were then escalated for inflation for subsequent analyses. They do not include the transition costs of the steps leading to physically setting up an SB.

[108] Some of the studies reviewed were: O'Connor, P. *Restructuring Recharged: The Superior Performance of Competitive Electricity Markets 2008 – 2016.* 2017; Fabrizio et al. *Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on US Electric Generation Efficiency.* 2007; Bushnell, J. & Wolfram, C. *Ownership Change, Incentives and Plant Efficiency: The Divestiture of US Electric Generation Plants.* 2005.

4.13 Financing mechanisms

IOUs usually finance capex through a combination of debt (short- and long-term) and equity (e.g., stock). Debt financing is when a firm obtains capital through the sale of debt instruments to investors, may they be individuals and/or institutions. Said individuals and/or institutions, in return, are promised the repayment of debt plus interest. Conversely, equity financing is when a firm obtains capital through the sale of shares, or essentially ownership interest. The sum of the cost of equity and debt financing represents a company's cost of capital, and the cost of capital represents the minimum returns a firm must make to satisfy all providers of capital.

Similar to an IOU, a co-op could finance capex through debt or equity. However, the sources and costs of acquiring capital are different for a co-op than for an IOU. The co-op entity's members may contribute equity to the purchase of assets, for instance. A co-op's margins in any year can be referred to as patronage capital, and each member's patronage capital account represents his/her portion of ownership in the co-op. Depending on the co-op's financial status, the co-op may return a proportion of the patronage capital to members as checks or bill credits, thereby considered as retired patronage capital. The remaining amount remains credited to members' accounts but is invested in the co-op, representing the equity capital provided by co-op members. Conversely, the co-op utility may choose to raise debt as rural electric co-ops have access to low-interest loans to fund acquisitions of other utilities through both public and private sources.

To finance the transition to the SB that is within the utility and its day-to-day operations, its revenue requirement would be combined with that of the utility and consequently recovered through electricity rates. The SB would thus be able to recover its costs related to power procurement and its operations.

In the case of an SB outside of the utility, a separate entity must be set-up that is not associated with the utility. To finance the day-to-day operations, the SB's revenue requirement would be recovered from fees assessed on consumers' electricity bills. These fees would need to be approved by the PUC. Alternatively, if set up as a government agency, the SB operations can be financed through funds appropriated by the legislature.

Task 1.6.5 *(Qualitative assessment of financing options)* provides an analysis of the potential financing options for each ownership model

4.14 Potential impact on the staffing needs of the PUC and DCA

The Project Team also looked at the effects of the change in the ownership model for the staffing needs of the PUC and the DCA.[109] Typical practices in other jurisdictions with the four ownership models were reviewed, and the oversight management and staffing needs of related State agencies and stakeholders under each model were assessed.

[109] Although there are several state agencies that interact with the electric utilities, the Project Team focused this Study on the PUC and DCA.

It is important to note that the roles and responsibilities of PUCs and DCAs vary significantly across jurisdictions. This is both due to functional roles as well as state energy policies such as the RPS. The scope of the study did not include a detailed staffing level assessment of Hawaii's PUC or DCA, and the relative comparisons should be assessed in that light. The assessments are done to develop an understanding of the upward or downward pressure on staffing requirements between the alternative ownership structures. Generally speaking, it could be observed that jurisdictions with more ambitious and active clean energy policies or initiatives tend to have more staff members but not necessarily higher staff-to customers ratios in relevant regulatory agencies.

Furthermore, the staffing needs and the salary levels are likely to remain stable or follow inflationary and/or GDP growth (similar to trends seen in the past) under the IOU model. For the co-op model, assuming reduced oversight of co-ops,[110] the staffing needs are expected to be lower by about 23% in the PUC and 21% in the DCA.[111] For the SB models, the staffing needs are generally higher by 10% in the PUC[112] (while the requirements in DCA remain unchanged) as the ownership transition requires more staff with specific technical expertise, increasing the budget for salaries (mainly to attract qualified staff for the new responsibilities).

There would likely be minimal changes in the management structure (or organizational chart) of the PUC and the DCA as the functional divisions will be needed regardless of the ownership model. Furthermore, the oversight management and staffing needs of related State agencies and stakeholders will be affected by various factors other than the electric utility's ownership model. Although the Hawaii PUC's mandate is limited to regulating the four electric utility companies, Hawaii's aggressive RPS, performance-based regulation, and other policy goals entail additional challenges to the regulatory and policy agencies. These other factors may require more staff members in these agencies, regardless of the ownership model selected.

Tasks 1.3.4/1.4.3 *(Assessment of how each ownership model impacts staffing of State agencies and stakeholders)* provides a more detailed discussion on the impact of the change of ownership model on staffing and management.

4.15 Potential impact on the penetration of DERs

DERs are resources that are interconnected to the electric grid at the distribution level, located close to the customers, and generally small in scale. DERs include distributed generation ("DG"), energy storage, demand response, energy efficiency ("EE"), and electric vehicles ("EV"). DERs offer several advantages; for example, they can improve grid reliability by co-locating generation and load, delaying or avoiding infrastructure investments, and offsetting emissions.

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[110] Currently, KIUC is under the authority of the Hawaii Public Utilities Commission, but as analyzed below, jurisdictions with many cooperatives are likely to have less oversight of cooperative utilities.

[111] Under the co-op model, the Project Team estimated the new number of positions in the PUC to be 50 ((65-50)/65 = 23%); for the DCA, the Project Team estimated the new numbers of positions to be 15 ((19-15)/19 = 21%).

[112] Under the SB models, the Project Team estimated the new staffing needs in the PUC will range from 65 to 70. An increase to 70 would represent an 8% increase.

A change in utility ownership models is generally not considered a key driver of DER adoption and deployment. Nevertheless, such a change could still have some impact on the penetration of DER because of variations among the models in terms of ease of access of the DERs to the system and the fair treatment of these assets.

Among the four ownership models reviewed, the two SB models and to an extent the co-op would likely be the most beneficial for increased penetration of DERs, more specifically DG and energy storage. In the case of the SB models, the SB's independence ensures that it would not have any bias with regards to the procurement or facilitation of interconnections of DG and energy storage resources. Likewise, a co-op (which is governed by its members) generally would be motivated to implement goals that would be beneficial not only to the utility but also consistent with the underlying policy objectives of its jurisdiction.[113] It is anticipated that there will be more energy storage under the co-op model, holding everything else constant, because it may be easier for the co-op to forge partnerships with landowners, who are also members of the co-op. Moreover, it is projected that there will be more energy efficiency programs under a co-op model to help members-customers to participate in conserving energy and saving on their electric bills. Meanwhile, under the IOU ownership model, there is likely a positive impact on DR programs as well as EV deployment because it is presumed that an IOU would have more resources and staff available to help implement these programs, as well as access to capital for the required investments (for EVs). Figure 29 illustrates the impact of the change in the ownership model on the penetration of DERs as well as energy security and reliability.

Figure 29. Impact of change of ownership model on the penetration of DERs and the energy security and reliability

Alternative regulatory model	Distributed generation	Energy storage	Demand response	Energy efficiency	Electric vehicles	Energy security and reliability
Move to IOU	—	—	↑	—	↑	—
Move to co-op	↑	↑	↓	↑	—	—
Move to Single Buyer (within the utility)	↑	↑	—	—	—	—
Move to Single Buyer (outside the utility)	↑	↑	—	—	—	—

Furthermore, the change in utility ownership would not impact energy security and reliability. Policies and regulations are already in place, ensuring that the achievement of RPS targets will not cause any issue with system security. Regardless of the ownership type, there are

[113] KIUC has had lower penetration of DERs compared to the HECO Companies. Whether a co-op would develop more DERs is subject to its costs and benefits compared with grid-scale renewables, status of renewable integration in the system, and many other factors.

requirements that the utilities need to fulfill and performance standards that they need to comply with.

Finally, higher DER penetration and deployment will be achievable under any ownership model provided that appropriate regulatory structures and incentives are put in place.

Task 1.5.1 *(Estimated potential for each model to increase distributed energy resources)* provides a more detailed discussion on the potential impact on the DERs of a change in utility ownership models.

4.16 Potential impact on the residential electricity rates

Based on the assumptions within the report, a change in ownership model could benefit residential ratepayers in Maui and Honolulu counties but may not in Hawaii and Kauai counties. In the three counties with an incumbent IOU, there are opportunities for the lowering of certain categories of costs through a change in ownership model, but there are also costs of transition to consider. Both opportunities and transition costs are higher under the co-op model. In Kauai County, the SB model is not expected to lower costs, but it can provide potential non-financial benefits in terms of reducing the potential for conflicts of interest in utility capital expenditure practices, as well as promoting state policies such as diversification of energy resources.

Meanwhile, a change to the co-op model in Honolulu and Hawaii counties is projected to increase average rates between 2018 and 2045 compared with rates in the Status Quo IOU model. This increase is driven primarily by the cost of purchasing the assets of the incumbent utility, assumed to be undertaken through 100% debt financing. As a result, the co-op model is expected to have a significantly higher debt burden (which includes interest payments). Since revenue requirements for co-ops are determined using the TIER-based approach, higher interest payments directly translate into higher rates. Furthermore, the need to raise additional debt financing to cover planned capex also drives higher rates under the co-op model than under the status quo. For revenue requirement modeling purposes, the Project Team assumed that the planned capex out to 2045 would be the same under all ownership models, based on the investment plan laid out in the HECO Companies' PSIP. While the Project Team acknowledges that a change in ownership model could potentially result in a different investment plan, such changes are impossible to predict even with extensive economic and technical analyses which were outside the scope of the present study. As such, to provide a comparable basis for the analysis of all ownership models, the Project Team opted to use publicly available data.

In the case of Honolulu and Hawaii counties, the costs of servicing the debt incurred for acquisition of the incumbent utility's assets together with the additional financing required for planned capex are expected to outweigh the cost reductions resulting from the move to a co-op model. These cost reductions can include lower projected expenses in contracting future power supply from IPPs, exemption from federal income taxes, and possibly lower operating expenses from a more lightweight structure. Although co-ops can generally secure debt financing at a lower cost than IOUs, the Project Team's analysis indicates that the benefit to ratepayers from co-ops' access to lower cost capital may not outweigh the increase in debt due to acquisition costs.

However, in Maui County, the acquisition costs and higher debt service burden based on the assumptions within would not completely negate the cost savings from the transition to a co-op

model. In such a scenario, the rates on average would be lower between 2018 and 2045 under the co-op model than under the IOU model. Notably, the Project Team expects that the costs for a co-op to acquire MECO's assets (estimated at $675 million) would be much lower than in Oahu ($3.25 billion for HECO) and Hawaii island ($761 million for HELCO).[114] Furthermore, future opportunities to lower costs are higher in Maui County as compared to Hawaii County because HELCO is already procuring a higher portion of its supply from renewable generation IPPs through long-term contracts.

It is important to note that throughout the forecast horizon, the forecasted rates under the three highly ranked ownership models for individual years could be higher or lower than rates under the Status Quo. Figure 30 summarizes the expected impacts on average rates between 2018 and 2045 under alternative ownership models when compared to rates under the Status Quo. Task 1.6.4. *(Matrix comparing system average retail rates under each ownership model)* provides a more detailed discussion on the projected average electricity rates by customer type from 2018 to 2045.[115]

Figure 30. Average impact of a change in ownership model on residential rates relative to the Status Quo (2018 – 2045)

Change of the Ownership Model	Honolulu County	Hawaii County	Maui County	Kauai County
Move to a co-op model	↑ 5.3%	↑ 8.2%	↓ -1.8%	
Move to a Single Buyer within the utility model	↓ -0.7%	↑ 0.3%	↓ -1.3%	↑ 1.0%
Move to a Single Buyer outside the utility model	↓ -0.8%	↑ 0.3%	↓ -1.3%	↑ 1.0%
Move to an IOU model				↑ 6.7%

On the other hand, the SB models are expected to lower average rates between 2018 and 2045 relative to the rates under status quo IOU in both Honolulu and Maui counties. It is anticipated that SB models deliver financial benefits to ratepayers by lowering the cost of the procurement of generation through increased competition such that the projected expenses of future power supply contracts with IPPs would be lower by 3% compared with expenses under the status quo. The SB models would deliver net economic benefits to ratepayers if the reductions in power supply costs outweigh the operating costs of an SB. As described in Task 1.6.1 *(Overview of the differences in how revenue requirement is calculated under each ownership model)*, the SB models are not projected to financially benefit HELCO's ratepayers as much as the other models because the

[114] The Project Team applied several valuation approaches, including discounted cash flow, trading comparables, and comparative transactions. The Project Team used the results of the comparative transactions analyses, based on a review of 9 precedent transactions involving comparable electric utilities. Note that these examples were with a willing seller.

[115] To derive the projected average retail rates under each ownership model up to 2045, a revenue requirements model was created for each ownership model and for each county. For the ownership models, a total of 16 revenue requirements models was created. Please refer to the following memos for additional information on the assumptions used and the results of the revenue requirements: Task 1.4.2 *(Economic evaluation of ownership and operation of each ownership model)* and Task 1.6.3 *(Estimated revenue requirements under each ownership model through 2045).*

utility's purchased power from future IPPs will be proportionally smaller than in the cases of HECO and MECO.

A change in ownership model from the Status Quo co-op in Kauai County is expected to increase rates on average between 2018 and 2045. A transition to an IOU model would increase the financing costs since IOUs have a higher weighted average cost of capital based on their cost of debt and their cost of equity. Likewise, the SB models would result in higher costs to KIUC's ratepayers because of the incremental expenses associated with SB operations but without direct financial benefits from lower purchased power costs, as the co-op model by nature does not reward capital expenditures in the same manner as with IOUs and as such, the SB would not necessarily purchase power at a cost lower than the co-op would. Task 1.4.2 (*Economic evaluation of ownership and operation of each ownership model*) provides a more detailed discussion on this subject.

Figure 31. Average impact on residential rates relative to the Status Quo (2018 – 2045) in Maui County – comparison of ownership change by the island and by county

Maui County – county-wide ownership model change	Maui	Lanai	Molokai
Move to a co-op model	-1.8%	-1.4%	-2.5%
Move to a Single Buyer within the utility model	-1.3%	0.8%	1.2%
Move to a Single Buyer outside the utility model	-1.3%	0.8%	1.2%

Maui County – ownership model change by island	Maui	Lanai	Molokai
Move to a co-op model	-1.8%	-1.4%	-2.5%
Move to a Single Buyer within the utility model	-1.3%	29.6%	29.1%
Move to a Single Buyer outside the utility model	-1.3%	31.2%	30.3%

Two approaches were evaluated with regards to a change in ownership structure for Maui County. The first approach analyzed a change in ownership model on an island-by-island basis, whereas the second approach assumed the ownership model is the same in a county-wide basis. If transitioning to a co-op model, both approaches result in identical outcomes because MECO's costs were allocated among the three islands in the same proportion under both methods. For the two SB models, the county-wide ownership change assumes that one SB is established for Maui County, and the associated costs are allocated to all three islands on a pro rata of their load. It is worth noting that if Lanai or Molokai were to change to a co-op and lose the economies of scale in shared administration and operations and maintenance costs from being coupled with Maui island customers, this could significantly increase the cost of implementing a co-op ownership model on Lanai or Molokai.

The ownership change in an island-by-island basis analysis assumes that an SB is established on each island. Creating a separate SB in Lanai and Molokai is projected to increase electricity rates in these islands because of the magnitude of fixed costs associated with the establishment and

operation of an SB relative to the overall utility expenses in these islands. The average impact on rates between 2018 and 2045 under both approaches are summarized in Figure 31.

In summary, the analysis shows that any of the recommended ownership models could lower electricity rates on Maui island while a co-op model could provide lower rates in Lanai and Molokai islands. The co-op model would be less expensive than other models on Lanai and Molokai because the savings from future power procurement on those islands, as compared to the Status Quo, would outweigh the cost of transitioning to the new ownership model, without the additional costs associated with setting up a new SB entity.

5 Potential regulatory models

5.1 Description of the potential regulatory models

The Project Team initially reviewed four families of regulatory models, in addition to the status quo COS approach. These models are not mutually exclusive, and some of them and/or their features could co-exist. These regulatory structures were determined based on legislative mandates, the emerging market trends in high renewables penetration jurisdictions, current state goals, and high-level evaluation of various additional potential regulatory arrangements. These models include the HERA model, independent system operator, distribution-focused regulatory model, and performance-based regulation ("PBR"), which are discussed in the subsections below. Note that PBR includes a wide spectrum of possible measures and that the Project Team reviewed several possible constructs within the PBR framework. Task 2.1.1. *(Summary comparison of Regulatory Models from Hawaii's perspective)* provides a more detailed discussion on these potential regulatory models.

5.1.1 Status Quo with increased oversight (or the HERA model)

The HERA model is assumed to be implemented as an addition to the current COS framework, referred to herein as the "status quo with increased oversight model" or "HERA model." HERA is a concept established by state legislation (Act 166) in 2012 to enforce reliability standards and interconnection requirements, as determined by the PUC. The Act authorizes the PUC to create the HERA entity, although the PUC has not created HERA as of this writing. The increased oversight from HERA would not change the current structure of the electricity value chain. Utilities would continue to operate the transmission and distribution network under this regulatory model. Nevertheless, the PUC's role in ensuring grid access and reliability would be transferred to HERA in this regulatory model.

North American Electric Reliability Corporation ("NERC")

The North American Electric Reliability Corporation ("NERC") is an entity currently operating on the US mainland in a somewhat comparable role to what was envisioned for HERA. NERC is the electric reliability organization for North America and responsible for developing and enforcing mandatory electric reliability standards as overseen by FERC. There are also other similar features between HERA and NERC. First, both are not-for-profit regulatory authorities. Second, they have the same mission of ensuring the reliability and security of the grid. Third, both are directed to develop and enforce reliability standards. Finally, HERA and NERC are subject to oversight by a regulatory body (e.g., PUC for HERA and FERC for NERC).

Moreover, the Project Team envisioned a Light HERA as a variation to this model. A Light HERA could be designed as an ombudsman; an appeals body focused on reliability and interconnection. It would have the technical capability to set target timeframes and standard models for calculating interconnection costs, which could be relied upon to settle customer challenges to utility interconnection behavior or lack of transparency about hosting capacity. In this model, HERA could only investigate after the customer has exhausted all the utility's internal appeals processes. HERA could also propose actions for the PUC to take if it finds that the utility has been

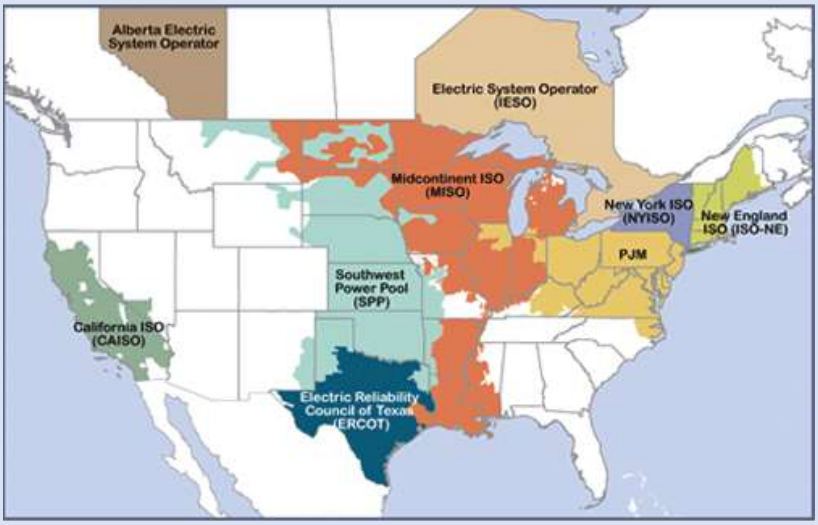
behaving arbitrarily. However, the intent is that a referral to HERA would serve as an incentive for the utility and its customer to settle differences.

5.1.2 Independent System Operator

An ISO or a regional transmission organization ("RTO") is an independent, membership-based, non-profit organization that ensures electric system reliability and uses bid-based markets to determine economic dispatch for wholesale electric power.[116] The concept of an ISO came from FERC's Orders Nos. 888/889 and subsequently the concept of RTO was introduced in Order No. 2000. More specifically, the creation of new institutions such as RTOs/ISOs was part of the restructuring process to address reliability through coordinated transmission planning while also facilitating open access. FERC, via Order 2000,[117] encouraged the voluntary formation of RTOs to administer the transmission grid on a regional basis throughout North America.

ISO/RTOs in North America

There are currently nine ISOs/RTOs in North America as shown on the map below. These include the Alberta's AESO and Ontario's IESO in Canada, as well as California's CAISO, the Southwest Power Pool, Texas's ERCOT, the Midcontinent ISO, the PJM Interconnection, New York's NYISO, and New England's ISO-NE.



An ISO structure typically aims to ensure reliability, which requires collaboration on the part of the ISO, transmission owners, and electricity utilities. This is ensured through:

- coordination of existing system components and processes to guarantee delivery of electricity upon demand;
- cooperation in monitoring and coordinating generation and transmission;

[116] EIA. *Today in Energy*. <https://www.eia.gov/todayinenergy/detail.php?id=790>

[117] FERC. *Order No. 2000 - Regional Transmission Organizations*. Docket No. RM99-2-000. December 20, 1999.

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www.londoneconomics.com

- communications and information sharing among all system operators to identify and isolate problems as they occur; and
- commitment by all electric utilities to continuously coordinate, cooperate, and communicate to protect and ensure system balance.

Under the ISO model, utilities continue to own and maintain the transmission and distribution system. However, utilities yield their functions of system planning, generation dispatch, and day-to-day operations of the bulk power system to the ISO. Under an ISO model, the incumbent utility could either retain its generation assets or divest them. In contrast to the Status Quo, this change allows IPPs to compete with the incumbent vertically integrated utilities on price in the wholesale market.

The PUC's oversight on resource planning, power purchase agreements, utility transactions, significant capital expenditure, service quality, and rates would remain the same. However, the tasks of ensuring reliability and long-term resource planning would be delegated to the ISO. The utility's previous role of coordinating movements of electricity would be transferred to the ISO as well.

5.1.3 Distribution-focused regulatory model

Currently, utilities own and operate the distribution grid. Although there are third-party entities such as solar installers, the technologies must still be connected to the utility grid. However, with the rapid growth of rooftop solar and the advancement of grid technologies, some markets have started to consider alternative business models for the distribution grid. A good example of a distribution-focused regulatory model is New York's Reforming the Energy Vision ("REV") process. Much like Hawaii State, New York State enacted policies to increase the use of clean energy and customer participation in the electricity sector. Its REV initiative is fundamentally altering the role of the utility from an entity that develops and maintains transmission and distribution assets (utilities in New York are generally not allowed to own generation assets), to an entity that enables the localized management of electricity supply and demand.

There are two potential implementations for a distribution-focused regulatory model that could be considered in the State of Hawaii. The first implementation assumes that the distribution infrastructure is still owned and operated by the incumbent utilities. This implementation is similar to New York's REV, where the distribution utility assumes the role of Distributed System Platform Provider ("DSPP"). The DSPP's new role, as envisioned by the New York regulator, would include "planning and designing its distribution system to be able to integrate DER as a primary means of meeting system needs."[118] Under REV, the DSPP would be required to "*use localized, automated systems to balance production and load in real time while integrating a variety of DERs, such as intermittent generation resources and energy storage technologies*."[119] Moreover, the

[118] NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*. Order Instituting Proceeding (issued and effective April 25, 2014). Page 12.

[119] Ibid. Page 13.

DSPP would also be required to "*take steps to ensure that distribution systems continue to be modernized through the use of 'smart grid' technologies*" and "*coordinate its planning functions with the implementation by customers of customer-sited DER.*"[120] However, this approach requires corresponding incentives to ensure that the utilities act in a way that supports the desired outcomes, such as allowing third-party access to the grid, making data available, etc.

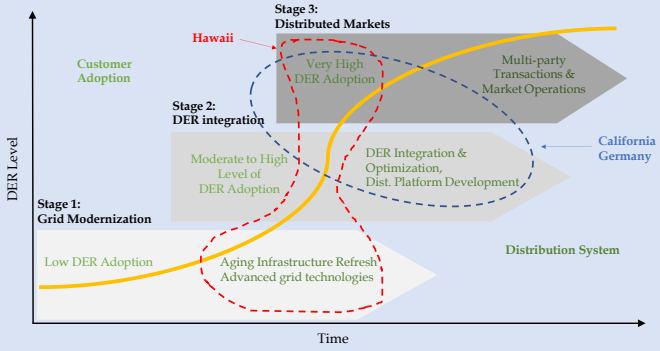
Examples of jurisdictions in the various stages of DER adoption

Currently, there is no jurisdiction that has a full-blown distribution-focused regulatory model. However, according to the Lawrence Berkley National Lab, there are generally three stages on the DER adoption:

- *Stage 1: Grid modernization* – DER adoption is reasonably low and can be accommodated by the existing technology levels in the grid. This stage represents the state of most existing distribution systems in the US.
- *Stage 2: DER integration* – DER adoption levels increase so that they are at the threshold level that will require enhanced functional capabilities to ensure reliable system operation.
- *Stage 3: Distributed markets* – a combination of very high DER adoption, enabling system technology investment and policy decisions to allow for the creation of distribution-level energy markets and multi-sided transactions.

As illustrated below, DER adoption is uneven across multiple service territories and, depending on the scale and nature of the adoption, would affect each system differently. However, at a conceptual level, it is possible to define a progression of levels of adoption. Figure 33 illustrates this adoption process as developed by DeMartini and Kristov in their report for Lawrence Berkeley National Lab's "Future Electricity Regulation" series.

Figure 32. DER adoption curves



Sources: LEI analysis and DeMartini & Kristov. Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation & Oversight. Lawrence Berkeley National Lab. October 2015.

[120] Ibid. Page 14 - 15.

The second implementation assumes that the distribution infrastructure is still owned by the utilities, but operated by an outside entity. This external entity, called the IGO, would be under the purview of the PUC, and operate and plan for the distribution system. The IGO is expected to execute the day-to-day operations of the grid and be responsible for planning for upgrades to the system. On the other hand, the utilities would maintain and make the required investments for the distribution assets. The utilities would also participate in the planning and operational process of the IGO. This is the same relationship that an ISO would have with transmission owners. However, due to the small size of Hawaii's bulk power system, the IGO would function as the system operator at both transmission and distribution levels. This would also allow the IGO to coordinate the use of utility-scale resources and DERs more efficiently. As the proportion of intermittent utility-scale renewables and DERs in Hawaii's power supply mix increases, improved coordination between transmission and distribution will become more critical in the maintenance of reliable grid operations.

5.1.4 Performance-Based Regulation

The current COS regulation may no longer provide the incentives that would encourage the utilities to meet the challenges related to the penetration of renewable resources and distributed energy. With these transformations, the performance expected from electric utilities would also need to change. The performance and role expected of the utilities have been expanded to cover other aspects of the business.[121] Through the *Staff Proposal for Updated Performance-Based Regulations* under Docket 2018-0088, the PUC Staff has identified prioritized outcomes. These include enhancing customer experience, improving utility performance, and advancing societal outcomes.[122]

PBR, compared with traditional COS, can induce desirable changes to utility behavior. PBR could include a variety of mechanisms that could be used in multiple ways and different combinations. PBR is best conceptualized as a continuum—ranging from "light" to "comprehensive" mechanisms—rather than a single type of regulatory regime (Figure 33).

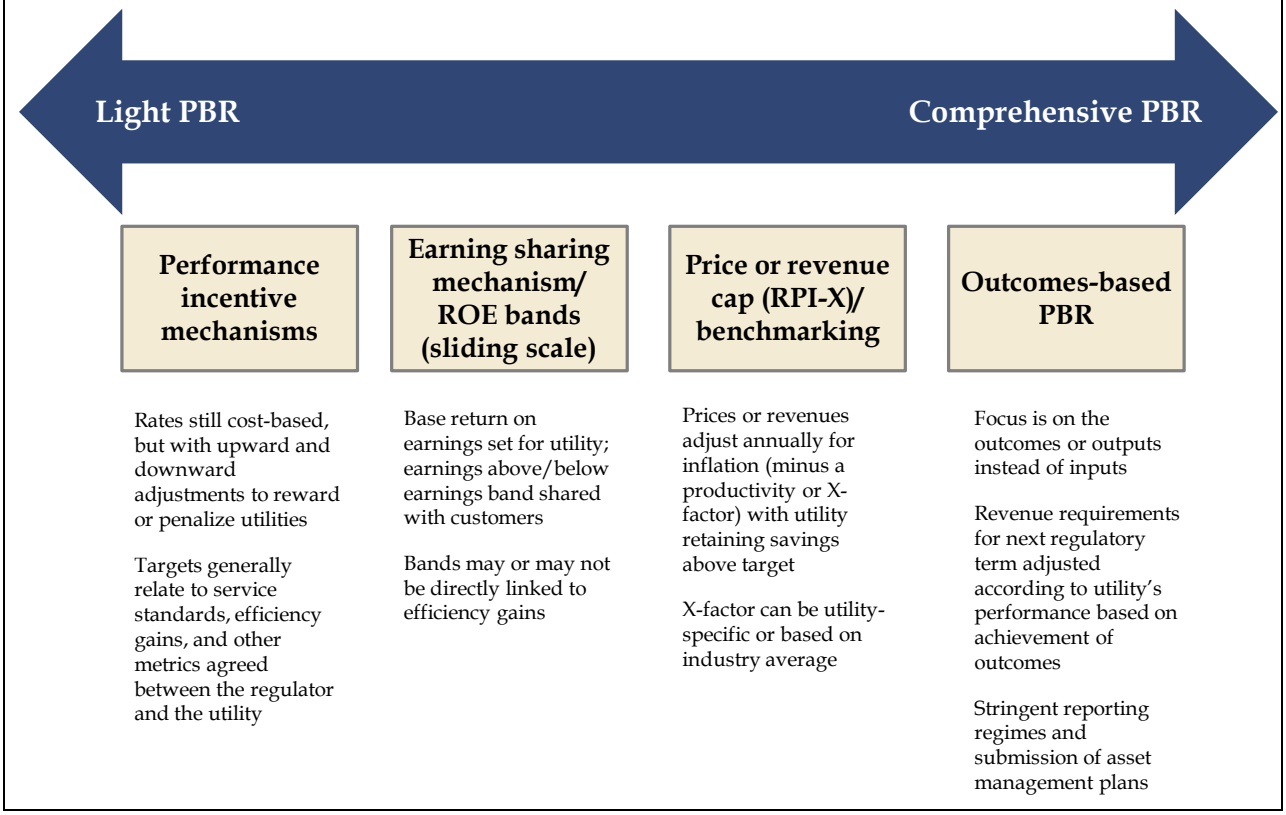
A model which could be thought of as Light PBR includes mechanisms such as PIM and an ESM where payments to the utilities are adjusted based on their level of performance vis-à-vis the target outcomes. The "medium" form of PBR mechanisms would include a rate cap where either the rates or the revenue is capped for the regulatory period. This cap helps promote efficiency as the mechanism tends to change the link between a utility's rates and its costs and improves efficiency. Task 2.2.1 provides a more detailed discussion on Light PBR.

At the end of the continuum is the Outcomes-Based PBR, which is the newest form of PBR where the focus is on the outcomes rather than the inputs to the revenue requirement calculations.

[121] For example, according to a 2017 report on electric utilities performance benchmarking, 257 Key Performance Indicators could be considered, which are clustered in five main categories, namely 1) customers, 2) operations, 3) environment, 4) human capital, and 5) corporate governance. It should be noted that these are examples, and that any tractable regime would have considerably fewer metrics.

[122] Hawaii PUC. *Staff Proposal for Updated Performance-based Regulation*. February 7, 2019. Page 17.

Figure 33. Continuum on PBR regulation (from "light" to "comprehensive" key mechanisms)



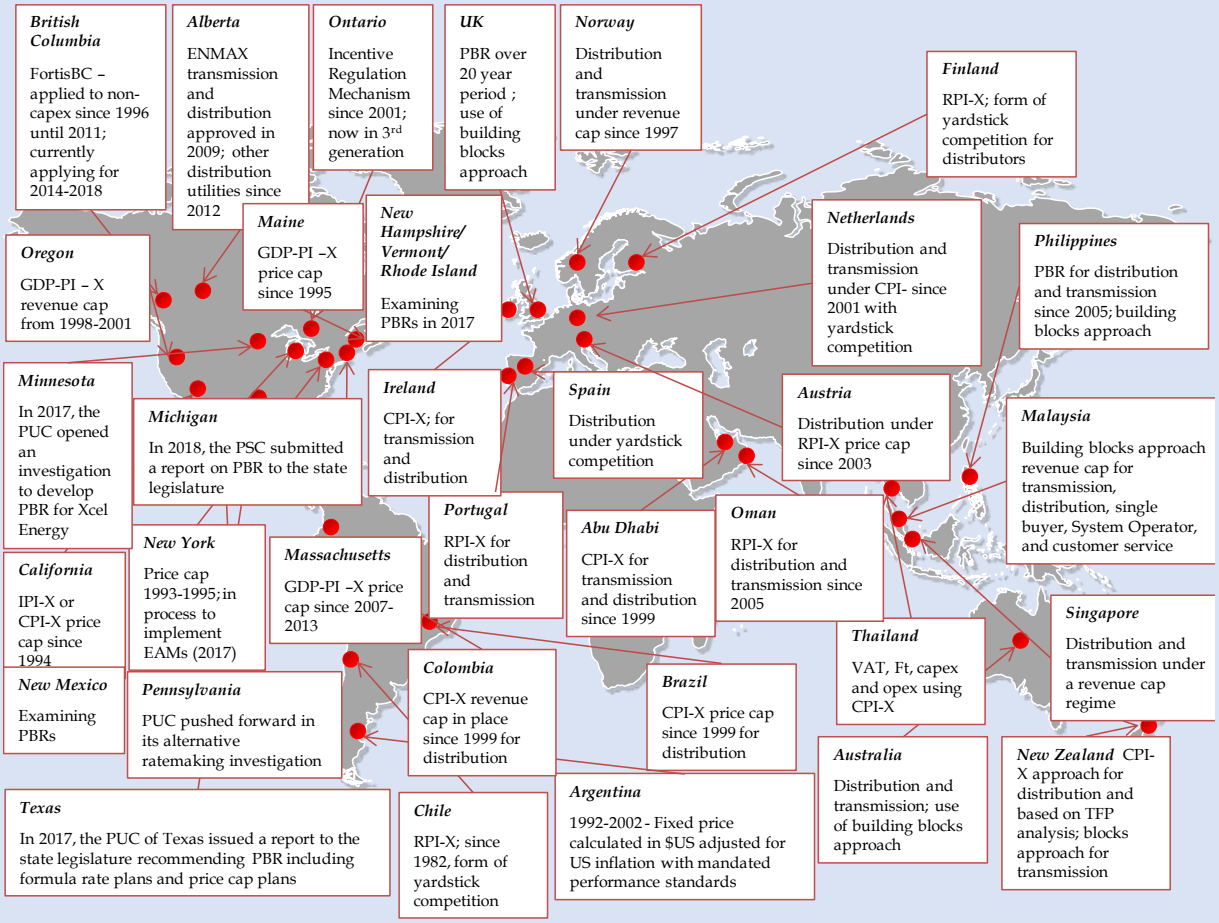
The "correct" implementation of PBR depends on the needs and values of the particular jurisdiction. Generally, the choice of a light versus a comprehensive PBR regime is determined by the risk appetite of the utility and the regulator, the range of incentives that the regulator is willing to approve, and the demands of and feedback from interveners. The "light" and "medium" forms of PBR can be considered as a "stepping stone" towards the comprehensive PBR mechanism. Section 5.3.4 provides more information about the benefit of PBR.

Aside from these key PBR mechanisms, there are also other components such as the length of the multi-year rate plan, productivity factor, treatment of unforeseen events or exogenous factors, off-ramp option, and flow-through factors.

Task 2.1.1 *(Summary comparison of Regulatory Models)* provides a more detailed discussion of these regulatory models.

Jurisdictions that have used, or are currently using or plan to move to PBR

PBR regimes exist in multiple jurisdictions throughout the world as shown in the map below. In North America, the markets that have used or is currently using PBR rate caps include British Columbia, Alberta, Ontario, Oregon, California, New York, Maine, and Massachusetts. Countries outside of North America, such as the UK and Australia, utilize a more comprehensive combination of PBR mechanisms. Some countries in Asia, such as Malaysia and the Philippines, are also implementing comprehensive PBR mechanisms. A list of potentially relevant jurisdictions that have PBRs is shown in the map below.



5.2 Potential PBR options for Hawaii

Three PBR options—Light PBR, Conventional PBR, and Outcomes-based PBR—were considered in the Study for Hawaii, based on the goals of the Hawaii Ratepayer Protection Act, which established "*performance incentives and penalty mechanisms that directly tie an electric utility revenues to that utility's achievement on performance metrics and break the direct link between allowed revenues and investment levels,*"[123] and PUC's aspirations of "*greater cost control and reduced rate volatility,*

[123] HRS §269.

efficient investment and allocation of resources, fair distribution of risks and fulfillment of state policy goals."[124] Figure 34 shows the key components of each PBR option and the subsections below discuss in detail these three PBR options.

Figure 34. Key components of each proposed PBR option for Hawaii

	Status quo	Light PBR	Conventional PBR	Outcomes-Based PBR
Regulatory term	3 years	3 years	3 years	5 years
Rate-setting approach	Cost of Service	Cost of service	Revenue cap using indexing formula (e.g., inflation less productivity factor)	Revenue cap using building blocks approach
Performance incentives mechanisms	• Reliability (SAIDI and SAIFI) (penalty only) • Call center performance • Cost savings in renewable generation procurement (rewards and penalties) • Implementation of demand response portfolio (rewards only)	Expand current list to include metrics in the following categories: • Availability • Reliability • Cost control • Service quality • Customer engagement • Competitive procurement • RPS targets	Similar to Light PBR: • Availability • Reliability • Cost control • Service quality • Customer engagement • Competitive procurement • RPS targets	Based on the outcomes to be achieved, the PIM list is more comprehensive than Light and Conventional PBR: • Customer satisfaction • Service quality • Customer engagement • Availability • Reliability • Safety • Cost control • Asset management • Connection of renewable generation • Connection of DERs • RPS target • Demand response implementation • Competitive Procurement • Financial ratios
Earnings sharing mechanism ("ESM")	Asymmetrical ESM where customers will be credited: • 25% of share if the actual ROE is more than 1% of the authorized ROE • 50% of share if the actual ROE is over 2% than the authorized ROE • 90% of share if the actual ROE is over 3% of the authorized ROE	Similar to current ESM where customers share the excess earnings	ESM is symmetrical in terms of sharing percentages and deadbands. Deadbands are larger to reflect risks	Similar to conventional PBR where ESM is symmetrical
Treatment of capital and operating expenditures	Capex included in the rate base; O&M passed through	Similar to current approach	Total expenditure ("totex") approach	Totex approach

SAIDI: System Average Interruption Duration Index SAIFI: System Average Interruption Frequency Index

[124] PUC. *Order No. 35411 Instituting a Proceeding to Investigate Performance-Based Regulation.* Docket No. 2018-0088. April 18, 2018. Page 52.

The PBR regime in the succeeding regulatory periods would evolve and be tailored to the specific environment and circumstances of the utilities. One of the lessons learned from other jurisdictions that have successfully implemented PBR is the need to adapt to changes when necessary. For instance, in the UK, the Office of Gas and Electricity Markets ("Ofgem") has routinely made modifications to the PBR regulations after each regulatory period to improve a particular mechanism that did not work as anticipated or to adapt to changes in the regulatory environment.

5.2.1 Light PBR

Light PBR builds upon the existing regulatory model and would expand the current set of PIMs to include other performance metrics, facilitating more effective achievement of the state's energy goals. Revenue requirements would be determined using the COS approach, with the utility subject to penalties and rewards for achieving or missing the targets. The expanded set of PIMs would not replace but work in conjunction with all other current performance and customer service standards set by the PUC, together with any guaranteed minimum service levels standards. The regulatory term would be the same as the current general rate case cycle of three (3) years. Finally, Light PBR would include the current ESM where earnings above the threshold would be shared with the customers.

5.2.2 Conventional PBR

Conventional PBR would use an indexation formula to determine the revenue requirements of the utilities. The indexation formula is based on inflation less a productivity factor. The inflation factor provides a mechanism through which the utility's revenues may be adjusted annually to reflect expected cost increases. On the other hand, the productivity factor is the rate of change in efficiency that is expected or targeted. There is an expectation that if the utility achieves the productivity factor, then it would be able to earn its allowed rate of return.

The revenue requirements calculation would utilize a revenue cap instead of a price cap. Given the increasing availability of customer-sited, distributed generation, and flat or declining forecasted demand in the State, a revenue cap would be a better option for the State. Indeed, a revenue cap would be more compatible than a price cap for Hawaii considering its policies of encouraging conservation, demand response programs or energy efficiency because it removes the conflict between regulation and policy goals to a significant degree. Revenue cap also allows for more pricing flexibility and is preferable when costs do not vary significantly with sales volumes or when volume changes are less predictable. Furthermore, a revenue cap (as is also the case for a price cap) would incentivize utilities to minimize overall costs since revenues are fixed and they could generate more profits by operating more efficiently and spending prudently.

There would also be an ESM under Conventional PBR, although larger and symmetrical deadband and sharing percentages would be adopted. The percentage share between the utility and consumers would be the same (e.g., 50% for utility and 50% for customers) and the deadband for gains and losses would be the same between the utility and consumers but larger (e.g., +/- 200 basis points). Having a larger deadband under this model is necessary to provide the utilities the opportunity to earn a higher return given the higher risk associated with the indexing formula

in determining the rates. The ESM is aligned with the PUC's aim of having a mechanism that results in *"fair distribution of risks between utilities and customers."*[125]

Moreover, the PUC's objective is to develop a mechanism that results in *"efficient investment and allocation of resources regardless of classification as capital or operating expenses."*[126] The model would, therefore, include a total expenditure approach ("totex approach"), where there is no distinction between capital and operating expenditures. In this way, the utilities would be expected to use the most cost-effective solution to achieve an outcome. Moreover, it will eliminate the issue of determining the boundaries between operating expenditures ("opex") and capex, which entails a significant amount of time and regulatory costs.

Lastly, the Conventional PBR model would also feature the same regulatory term (3 years) and a set of PIMs as the Light PBR model.

5.2.3 Outcomes-based PBR

Outcomes-based PBR, which is similar to the UK's RIIO model ("Revenue=Incentives+Innovation+Outputs"), would focus on the outcomes related to enhancing customer experience, improving utility performance, achieving public policy goals, and attaining healthy financial performance. Based on these outcomes, the performance categories and measures for each group would be determined. Unlike Light PBR, Outcomes-based PBR would require a more comprehensive set of PIMs. The Commission would need to have a rigorous performance reporting and monitoring process to determine if the expected outcomes are being achieved.

Under Outcomes-based PBR, the HECO Companies would be required to develop a robust business plan that sets out what they intend to deliver and achieve during the regulatory period. The plan should include target revenues from existing and future customers to ensure the achievement of outcomes. It would also provide evidence of the utility's cost and revenue forecasts and detailed investment plans for the regulatory period.

Furthermore, the HECO Companies would be expected to file capital and asset management plans to support their rate application. They would need to provide evidence that their planning and prioritization process is rigorous to justify the proposed capital budget. In particular, the plan should be able to explain how the utility sought to control costs in relation to its proposed investments, for example, through appropriate optimization and prioritization of investment expenditure. Utilities should also establish that the plans benefited from meaningful consultation with customers and stakeholders. The Commission would be expected to monitor capital spending against the approved plans by requiring utilities to report annually on actual amounts

[125] Public Utilities Commission. *Order No. 35411 Instituting a Proceeding to Investigate Performance-Based Regulation*. Docket No. 2018-0088. April 18, 2018. Page 52.

[126] Public Utilities Commission. *Order No. 35411 Instituting a Proceeding to Investigate Performance-Based Regulation*. Docket No. 2018-0088. April 18, 2018. Page 52.

spent. A large disparity between actual expenditures and those reflected in the plans could trigger a Commission investigation.

Similar to Conventional PBR, a revenue cap mechanism would be used in this model to align with the public policies and energy goals of the State. However, in contrast to Conventional PBR, the rates under an Outcomes-based PBR model would be based on a five-year forecast of the utility's revenue requirement and sales volumes. This means that unlike Conventional PBR where the rate for the next two years of the regulatory period would increase according to an indexing formula,[127] the revenue requirements would already be determined for the next five years based on the utility's revenue and sales forecasts. Moreover, a longer regulatory period (preferably five years) would be more appropriate under Outcomes-based PBR to better align the rate setting with the planning horizon of the utilities. This extended term would also strengthen efficiency incentives and help manage the pace of rate increases for customers through adjustments that are calculated to smooth the impact of forecasted expenditures.

Generally, a building blocks approach is used to forecast the revenues in this model which requires a forecast of total costs (e.g., operating expenses, return on investment, depreciation expenses, taxes, etc.) for each year of the regulatory term. The forecast considers productivity improvements, targets, and necessary capital investment. In other words, unlike under the conventional PBR where productivity (or the "X") of the I-X formula is applied to otherwise COS-based rates, the productivity improvements under the building blocks approach are embedded in the forecasts. Therefore, under a building blocks approach, there is a need for extensive benchmarking analysis to set efficient costs. These total costs would then be added together—hence, "built up"—to determine an allowed revenue requirement for the utility based on estimates of the utility's expected capital and operating costs, and return on rate base assets.

Finally, similar to the Conventional PBR, the symmetrical ESM and totex approach would also be incorporated in this option. Task 2.2.1 (*Summary comparison of Regulatory Models from Hawaii's perspective*) provides a more detailed discussion on the potential PBR mechanisms for the State of Hawaii.

5.3 Advantages and drawbacks of each regulatory model

The current regulatory model has several strengths including the PUC's independence and innovativeness, as reflected in its openness to deviation from traditional ratemaking by instituting various elements of PBR and incentive mechanisms; a participatory regulatory process that raises the public's confidence in the Commission; a model that allows rates to be set, allowing utilities a reasonable rate of return; and presence and implementation of policies that support the diversification in the State's energy portfolio. However, there are several potential improvements that can be made in the current regulatory model. These include the need to provide incentives that will encourage superior utility performance on specific metrics, provide certainty with

[127] The first year rate of the regulatory term is the going-in rate which is determined through COS as discussed in Section 3.3.1. The rates for the second and third year are based on the indexing formula, which is based on the increase in inflation less approved productivity factor.

regards to timeline on issuing regulatory decisions, and reduce complexity and cost of regulation and regulatory compliance.

The advantages and drawbacks of each model are summarized in Figure 35 and further discussed in the following subsections. Task 2.2.1 *(High-level evaluation of the regulatory models relative to the State's goals)* provides a detailed discussion of the advantages and drawbacks of each regulatory model.

Figure 35. Summary of advantages and disadvantages of each regulatory model

	Pros	Cons
HERA model	• Enforcement of open access and reliability standards • Long-term view of reliability needs • Recommend specific reliability standards relevant to Hawaii context • Can develop into a center of excellence, expertise and best practices	• Risk of ambiguity of roles between Commission and new entity • Increased cost of HERA to fall on ratepayers
Independent grid operator	• Efficiency gains of competition in the power supply market can lower costs to consumers and eliminate subsidies • Additional benefits, such as improved reliability, better coordination, and reduced transaction costs	• High level of stakeholder engagement required to initiate • Careful market design needed to mitigate implementation risk • Additional costs required in terms of implementation costs
Distribution-focused regulatory model	• Potential for lowering costs to consumers as they shift consumption during peak hours via DERs • Market efficiencies from increased competition of DER solutions	• Stranded cost risk exists which would be borne by consumers • Technical complexity presents risk of high cost of implementation • Extensive levels of consumer education required to optimize market participation • Few best practices to learn from
Performance-based regulation	• Drives innovation and better investment decisions • Efficiency gains from PBR mechanisms can be shared with customers • Incentive for utilities to operate more efficiently	• Significant regulatory work may be required to design the PBR • Requires lengthy stakeholder efforts
Lighter PUC regulation	• A reduction in regulations would reduce costs for both KIUC and the PUC	• Could result in the state's inability to ensure co-ops comply with state policy goals

5.3.1 HERA model

Having a separate entity from the PUC that performs oversight and monitoring of interconnection and reliability standards would allow for more stringent enforcement of technical and reliability standards as well as a streamlined, transparent, and standardized interconnection

process. An independent entity that reports to the Commission on reliability standards is likely to take a long-term view on reliability needs for each county and recommend specific technical and reliability standards as counties seek to meet the RPS targets for the State.

A HERA would ensure a fair and transparent interconnection process and is expected to safeguard system reliability, resiliency, and accountability. It would also recommend specific reliability standards relevant to Hawaii context, given the unique features of the State.

Moreover, as a separate entity dedicated to reliability standards monitoring and enforcement, HERA can develop into a center of excellence, expertise, and best practices with regards to distributed energy resources integration. This is provided by the legislation, which allows the Commission discretion as to the specific roles that HERA can play. With such a purpose, HERA should provide training and technical assistance to counties and utilities seeking to comply with the State's RPS goals and reliability targets.

Finally, a study—commissioned by the Mayor's Office of Economic Development of Maui County (August 2017)—assessed the initial structure for HERA.[128] The study found that an independent organization such as HERA could be beneficial to the State, particularly when it comes to overseeing the planning, reliability standards, and interconnection processes.

A variant of this model, a Light HERA, could be designed to improve the DER interconnection process as well as provide an independent assessment of the impact of DERs on local reliability. Its narrow scope would allow the entity to develop stronger expertise on DER interconnection and hosting capacity analysis than a body like the PUC, which has more wide-ranging responsibilities. Moreover, the expertise would add more weight to its decisions as an ombudsman in dispute resolution. Having a separate entity that oversees these functions would accelerate DER interconnections as well as the resolution of disputes that usually take months under current PUC regulatory proceedings. Furthermore, a streamlined body has lower overhead costs and is less likely to create overlapping layers of jurisdiction and bureaucracy.

However, a HERA model faces the risk of overlap of roles between the Commission and the new entity. Currently, the Commission is responsible for enforcement of reliability standards across the State. The establishment of HERA would require the Commission to define the mandate of the new entity and potentially transfer this role to HERA, with the new entity reporting back to the Commission on its activities for the preceding year on an annual basis.[129]

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[128] Mayor's Office of Economic Development, Energy Commissioner, DKK, and SES. *Comparing the Structure and Function of a HERA to an ISO: Report and Task Analysis for use by the County of Maui.* August 25, 2017.

[129] Under the HRS 269-149, the Commission requires that the HERA entity, "*report to the commission each year on the date of agreement under section 269-147 following the original contracting between the Hawaii electricity reliability administrator and the commission on the status of its operations, financial position, and a projected operational budget for the fiscal year following the date of the report.*" (Source: Hawaii Revised Statutes, *HI Rev Stat § 269-149 (2017*), 2017).

Another potential challenge in the establishment of a HERA entity is the required funding—which would ultimately fall on ratepayers.[130] The surcharge implemented to fund the HERA entity would be recoverable from ratepayers and, by definition, increases rates (with all other costs staying the same). In the Maui County Study, the authors concluded that it is difficult to demonstrate that the costs for the establishment of a separate entity would be covered by savings from changes to interconnection or reliability.[131]

5.3.2 IGO

The main benefits of an IGO regulatory model are typically bifurcated into quantifiable benefits, i.e., efficiency gains of competition in the power supply market and elimination of subsidies; and additional benefits, such as improved reliability, better coordination, and reduced transaction costs. This model would operate similarly to ISOs on the mainland US but would also have control over the distribution grid given the relatively small scale of the state's electric grids.

Efficiency gains have been demonstrated in relevant empirical studies that have examined costs to consumers in the years following deregulation and creation of a wholesale power market. In one highly-cited empirical analysis of the outcomes of the PJM market, market participants realized increased gains of over $160 million over the first year.[132] A similar study of the initial benefits of the New York ISO market estimated net annual benefits equivalent to 5% of system-wide production, which is determined to have a value of over $150 million.[133]

Finally, an IGO model reduces conflicts of interest. Transferring the operations of the transmission system to an IGO would lower the conflicts of interest that Hawaii's utilities face under the status quo model. Currently, the utilities own transmission assets but are also responsible for the maintenance of reliability and resource planning. The utilities can include transmission assets in their rate base and earn a regulated rate of return on them because they are incentivized to implement solutions that require larger capex spending or favor utility-owned generation assets, to ensure reliability and resource adequacy. With the separation of planning and ownership, the utilities become passive transmission owners and must follow the resource plans endorsed by the IGO and approved by the PUC. The IGO's independence can address the capex bias that IOUs have in the current regulatory model.

Admittedly, the IGO model is a technically complicated industry structure and requires highly specialized staff to ensure round-the-clock coordination. The costs—in terms of time, effort, and

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[130] Under the HRS 269-146, the Commission may require by rule, or order, that "*all utilities, persons, businesses, or entities connecting to the Hawaii electric system, or any other user, owner, or operator of any electric element that is a part of an interconnection on the Hawaii electric system shall pay a surcharge that shall be collected by Hawaii's electric utilities.*" (Source: Hawaii Revised Statutes, *HI Rev Stat § 269-146 (2017*), 2017).

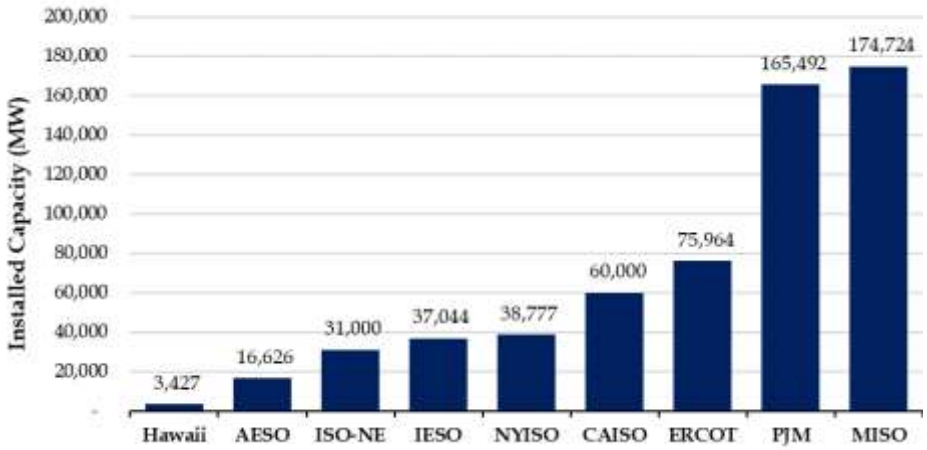
[131] Ibid.

[132] Mansur, E. & White, M. *Market Organization and Efficiency in Electricity Markets.* January 2012.

[133] Tierney & Kahn. *A Cost-Benefit Analysis of the New York Independent System Operator: The Initial Years*. March 2007. P.39.

expense—to create staff, and transition reliably to a new market structure are very significant. All of these additional costs will be borne by ratepayers. In Hawaii, these costs may double as the lack of interconnection among the islands will necessitate multiple markets running independently, all to be coordinated by a single entity.[134] An estimate of the costs of the creation of an ISO (performed by FERC staff) suggested that annual operating costs would impact the average customer by 0.02¢/kWh, with an initial investment of between $50 million and $70 million for hardware and fully operational software (that will calculate available transmission capacity and schedule transmission and dispatch through a centralized control center).[135] The smaller size of Hawaii's electricity system (compared with other jurisdictions with ISOs and RTOs in North America) likely requires higher fixed costs for the creation of an IGO on a per capita or a per kWh basis (Figure 36).

Figure 36. Installed generation capacity in North American jurisdictions



Source: FERC, Electric Power Markets: National Overview; IESO, 18-Month Outlook, June 2018; AESO, 2017 Annual Market Statistics.

Aside from the smaller size of Hawaii's electricity system in terms of customers served or installed capacity, the transmission networks are also significantly smaller. As described earlier, the State of Hawaii has less than 1,900 miles of transmission lines—817 miles in Honolulu County, 622 miles in Hawaii County, 258 miles in Maui County, and 171 miles in Kauai County.[136] Most of the electric grid operates on lower voltage—13.5 kV to 69 kV; only Honolulu County operates

[134] This is currently the case in Mexico, where the state of Baja California is islanded from the rest of the Mexican grid, and as a result, three markets operate in parallel, i.e., the Baja California Interconnected System, the National Interconnected System and the Baja California Sur Electric System. These three markets are monitored by the National Center for Energy Control (Centro Nacional de Control de Energía), all referred to as the Mexican Wholesale Electricity Market, which is established as a cost-based short-term energy market with a day-ahead market and a real-time market. (Sources: SENER; IEA, *Mexico Energy Outlook*. World Energy Outlook 2016.)

[135] FERC Staff. *Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization*. Docket No. PL04-16-000. October 2004.

[136] Task 1.1.2 memo.

higher voltage lines at 138 kV. Higher voltage distribution lines operate at 4 kV and 12 kV.[137] Therefore, the distinction between transmission and distribution components of the power delivery system in Hawaii is not as large or as distinct as on the mainland US.

Furthermore, as several, aging fossil fuel-fired power plants retire, they are being/would be replaced primarily by smaller renewables-based plants (alongside more efficient diesel units). When combined with increasing levels of DERs, the distinction between transmission and distribution is further blurred. Therefore, the roles of an ISO and an independent distribution system operator ("IDSO") are likely to have more overlap than differences in Hawaii.

Finally, IGO models and wholesale markets require careful market design because a poorly designed market may lead to unintended outcomes such as price spikes and damaged investor confidence. This implementation risk is not insignificant and has been demonstrated to result in inadvertent outcomes, particularly in the event of incomplete reforms.[138]

5.3.3 DSPP model

The DSPP model has the potential to lower costs for consumers who, with appropriate incentives, will tend to reduce consumption from the grid during peak hours by optimizing DER solutions such as storage as well as benefiting from efficiency gains from the competition in the DER solution markets. Moreover, market efficiencies from increased competition would likely result in lower costs. As in any other market, competition motivates players toward technological improvement and product diversification (such as cheaper backup power options) that meet the various needs of consumers.

Furthermore, providing a platform would facilitate greater penetration of renewables and DERs. DERs in certain jurisdictions have been observed to reduce distribution grid costs, eventually lowering costs on the side of consumers.[139] Benefits from improved coordination may include a reduction in line losses, which can potentially link to a reduction in surplus procurement of generation.

The DSPP model also provides wider grid access for behind-the-meter generation resources or DG. Currently, DG resources in Hawaii are predominantly rooftop solar photovoltaic ("PV") panels. Increasing use of battery-backed rooftop solar energy systems may occur as prices of batteries continue to fall. In the status quo model, the distribution system is operated by vertically integrated utilities that own both generation and distribution-level infrastructure. They do not

[137] HECO. *Power Facts – Power Delivery.* Web. <https://www.hawaiianelectric.com/about-us/power-facts/power-delivery>

[138] Joskow, P. *Lessons Learned from Electricity Market Liberalization.* The Energy Journal. 2008.

[139] In 2014, Consolidated Edison, a distribution utility in New York, projected a shortfall of 69 MW in its feeders for substations in the boroughs of Brooklyn and Queens. As an alternative to a $1.2 billion spending in substations and feeders, the utility proposed and implemented a $200 million DER program, which involved 17 MW of infrastructure investment and 52 MW of demand-side solutions. (Source: New York PSC, *Order Establishing Brooklyn/Queens Demand Management Program.* December 2014. Case 14-E-0302)

have the incentives to support the growth of DG because it lowers sales from utility-owned generation and could reduce the need for distribution-level infrastructure. A DSPP would offer more avenues for DG resources to monetize the value they provide to customers and the grid. DG owners can sell electricity to the grid or directly to other customers. They may also be compensated for lowering local peak loads, helping to avoid or defer costly infrastructure upgrades.

Notably, the DSPP model leads to stranded cost risks inherent in a high DER penetration scenario. High DER penetration in the grid may result in decreased network load over time as customers increasingly switch their consumption during peak hours and/or become prosumers[140] in the market. This will likely increase the risk of stranded utility assets—the costs of which will be borne by remaining utility consumers, most of whom may be lower-income customers who are unable to take advantage of the benefits of owning DER technologies.

The distribution regulatory model would require substantial enhanced functional capabilities from the distribution utilities while the complex grid infrastructure required to facilitate it may require high-cost investments.[141] This would also need extensive levels of consumer education to ensure success. DeMartini and Kristov of the California Institute of Technology and California ISO, respectively, note that the success of this regulatory model requires "advanced grid platform technologies and operating procedures for the distribution utility to call upon the DERs when needed in real time and track performance" as well as the development of "methods to identify needs of the system by location, determine hosting capacity, assess potential benefits of DERs on a particular feeder and distribute DERs optimally" within the distribution service area.[142]

To compound these risks, there are not many precedents; therefore, few best practices to learn from. Distribution-focused models are currently at various stages of implementation in California and New York, but few medium- to long-term analyses have been carried out on the impacts of these transitions on utilities and ratepayers.

Finally, as DER penetration increases, the possibility for bias and barriers to DER development from incumbent utilities could pose risks in the areas of distribution planning, DER interconnection procedures, and real-time operations. As detailed by DeMartini and Kristov, the Commission must remain vigilant as transparency, non-discrimination, and the need to minimize the risk of stranded investment becomes increasingly important due to the diversity of new

[140] Prosumers are both producers and consumers of energy. They have on-site distributed generation behind the meter, allowing them to sell surplus power back to the grid.

[141] Distribution networks typically have very little real-time monitoring and control built into their networks, as these generally have been limited to higher voltage levels and typically used for management of faults, thus extensive transmission upgrades may be required. (Source: Bell, K. & Gill, S. *Delivering a highly distributed electricity system: Technical, regulatory and policy challenges.* Energy Policy 113 (2018) 765-777.)

[142] DeMartini & Kristov. *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation & Oversight.* Lawrence Berkeley National Lab. October 2015.

players entering the DER landscape and the rapidity of changes in technologies and customer demands.[143]

It is worth reiterating that the role of an IDSO would be substantially like that of an ISO in Hawaii. The State's utilities are vertically integrated, unlike in other jurisdictions in New York and Europe with DSPP or IDSO models. In such larger and liberalized markets, distribution functions are well-separated from the bulk power system. Other system operators like an ISO or a Transmission System Operator oversee functions such as dispatch, scheduling, reliability, and coordination. In Hawaii, it may be more efficient to have one system operator at both transmission and distribution levels due to the small size of the State's bulk power system. As the proportion of intermittent utility-scale renewables and DERs in Hawaii's power supply mix increases, improved coordination between transmission and distribution will become more critical in the maintenance of reliable grid operations.

5.3.4 PBR

PBR mechanisms have some demonstrable advantages over COS regulation. PBR mechanisms have been shown to result in improved incentives for utilities and can be designed such that they drive innovation and better investment decisions from utilities. The PBR approach may reduce administrative and regulatory costs (e.g., due to fewer regulatory proceedings) as well as lead to more stable rates for customers.[144] A well-designed multi-year PBR with well-defined mitigation measures may also reduce regulatory risk on the utility, lowering its cost of debt and, ultimately, lowering costs to consumers.

Moreover, utilities are encouraged to operate more efficiently so they can achieve or surpass productivity targets. PBR can provide strong incentives to increase performance and improve productivity because it allows a utility to derive a significant financial benefit from doing so.[145] This benefit is precisely the incentive that motivates companies in competitive markets to control costs and deliver exceptional service to their customers. The experiences of some jurisdictions that have implemented PBR illustrate its beneficial role in encouraging productivity improvements. For instance, in the UK, Ofgem stated that the PBR regulatory framework has brought benefits to electricity customers over the last 20 years and has "delivered increased capacity and investment, greater operating efficiency, higher reliability, and lower prices."[146] In fact, "since privatization, allowed revenues have declined by 60% in electricity distribution and

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[143] Ibid.

[144] Rate stability under a PBR mechanism is a function of the rate setting formula. Utility rates, typically under an I-X approach will only increase by inflation (I) less the productivity factor (X) plus other flow-through mechanisms. This will be over multiple years, allowing for a longer-term outlook for utility rates. (Source: Olson, Wayne and Caroline Richards. "It's All in the Incentives: Lessons Learned in Implementing Incentive Ratemaking." *The Electricity Journal*: 20-29.)

[145] Sappington, David, Johannes Pfeifenberger, Philip Hanser, and Gregory Basheda. "The State of Performance-Based Regulation in the US Electric Utility Industry." *The Electricity Journal*. October 2001.

[146] Ofgem. *Regulating Energy Network for the Future: RPI-X@20 Emerging Thinking*. January 20, 2010. P. 50.

30% in electricity transmission. These reductions have been achieved without sacrificing capital investment, which has continued across all sectors since privatization."[147]

Efficiency gains from PBR mechanisms can be shared with customers through ESM. An ESM can also lower costs to consumers and ensures effective customer participation in a company's financial performance.[148] As discussed in Section 3.3.1, an ESM has been implemented in Hawaii along with the RAM since 2011, as part of the Revenue Decoupling Mechanism approved by the PUC.[149]

Reliability can also be safeguarded under a PBR regime, especially for plans that have mandated performance standards, which in some jurisdictions also entail a system of penalties and rewards. The presence of incentives provides a strong motivation for utilities to improve their quality of service. For instance, Ofgem believed that the implementation of PBR "has led to significant improvements in quality of service. Between 1990 and 2009, the number and duration of reported outages fell by around 30 percent."[150] With performance standards in place under a PBR regime, distribution line losses may also improve.

Moreover, the PBR model could reduce administrative and regulatory costs in the long term by reducing the number of litigated rate cases for the utility. This is particularly true for the existing Hawaii regulatory framework, where the duration of the rate case application is over 24 months.[151] Reduced regulatory costs under PBR are a result of PBR's recognition of the information asymmetry between the regulatory body and utility. Under COS, regulators spend a considerable amount of time and expense to bridge the information gap.

Moving from a traditional COS to PBR can be a major undertaking not only for the regulator but also for the utilities. It involves a significant amount of regulatory work and requires lengthy stakeholder efforts to determine the appropriate PBR mechanism that may be implemented and allow more in-depth analysis of sectoral and technical issues, discussions of which are not always present or as thoroughly dissected during a COS deliberation.

Sufficiency of capex funding under a PBR approach can be a concern if there are no other capital incentive mechanisms in place other than the indexing formula (inflation less productivity factor) or if the explicit capital incentive mechanism provided is very restrictive. Including a capex

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[147] Ibid.

[148] Sappington, David et al. *The State of Performance-Based Regulation in the U.S. Electric Utility Industry.* 2001. The Electricity Journal. P. 71-79.

[149] Hawaii PUC. *RAM Legal Notice.* March 31, 2011. <https://puc.hawaii.gov/wp-content/uploads/2013/06/20110427-RAM-legal-ad.pdf>

[150] Ibid.

[151] LEI analysis of rate cases between 2009 and 2017 for the HECO companies showed that of the seven (7) rate cases reviewed, three (3) took at least 30 months to decide, while only one (1) was settled in less than 10 months. (Source: Hawaii Public Utilities Commission).

mechanism within the PBR formula or, at a minimum, incorporating a feature to reduce regulatory risks associated with capital outlays beyond the control of management may provide for increased stability and ensure the longevity of a PBR mechanism.

PBR mechanisms face forecasting requirements and challenges. The preparation of PBR filings requires the ability to forecast additional elements that may have been less critical under a COS regime.[152] Poor forecasting on the side of utilities can also lead to potential additional costs and/or penalties affecting their bottom line.

In summary, advantages and drawbacks of PBR models can vary based on where a particular PBR design falls (i.e., in the range from light to comprehensive mechanisms). Implementing more comprehensive PBR regulation can yield more profound benefits but at higher risk to both shareholders and regulators. A greater proportion of utility revenues or costs are tied to incentives, which lowers the burden to maintain frequent regulatory oversight – more comprehensive PBR models typically also have a longer regulatory period, thus reducing the frequency of rate case proceedings. Utilities are encouraged to pay more attention to their performance with respect to metrics defined by the PUC, driving greater innovation as they seek to improve performance while reducing costs.

5.4 Similarities and differences of the regulatory models

Each of the regulatory models discussed previously represents a different approach to the regulation of the State's power sector. Some of these regulatory models (such as the HERA, ISO, and distribution-focused regulatory models) require delegating some of the responsibilities of the PUC to an independent entity while others such as PBR would require a change in utility oversight from the PUC. These regulatory models were reviewed across three key parameters to ensure coherence and consistency. An overview of the analysis is shown in Figure 37.

Utility's role across the value chain

Both the Status Quo and PBR regulatory models maintain the existing structure, where the HECO Companies and KIUC are vertically integrated and regulated by the Commission. Under the HERA model, the existing regulatory model is augmented with the creation of HERA. The utilities will maintain their current roles across the electricity supply value chain. However, the utilities will be required to meet reliability and open access requirements under the oversight of HERA.

Meanwhile, under the ISO regulatory model, the newly formed ISO either acquires or leases the transmission control and monitoring assets of the utilities. The utilities retain ownership over the transmission assets and control ownership of the distribution system. Under the distribution-focused regulatory model, the utilities facilitate the integration of DERs into the grid and are encouraged to provide DSP services. In this regulatory model, the Commission may also mandate

[152] Items that need forecasting include load growth, energy growth, depreciation, number of customers, cost of capital, and operating, capital and tax expenditures, to name a few.

the creation of an IDSO, which would perform the same duties as an ISO essentially but focused on the distribution-level system.

Figure 37. Comparison of characteristics of the regulatory models

	Status Quo	Status quo with increased oversight	ISO	Distribution-focused regulation	PBR
Utility role across value chain					
Asset ownership	X	X	X	X	X
Asset operation	X	X	X	X	X
Investment planning and execution	X				
Utility incentives					
Incentive to increase/decrease spending	X				
Incentive to increase/decrease investment	X				
Maintain operational control	X	X			X
Regulated revenues in ratebase	X	X	X	X	X*
Market-based revenues			X	X	
Oversight and monitoring					
PUC	X	X	X	X	X
Independent monitor		X	X	X	

*: In some variations of the PBR framework, the typical definition of ratebase representing capital expenditures is replaced with an approach allowing utility to earn returns on total expenditures (operating + capital expenditures)

Note: "X" indicates that the feature is present in the model.

Regulatory model impact on utility incentives

Under all the selected regulatory models except for PBR, most or all of the sectors of the value chain will still rely on a rate base or COS approach to determine revenue requirements. In this model, there is an inherent bias for the utility to spend more on capital infrastructure instead of operations and maintenance to increase returns for shareholders. Under the proposed PBR mechanisms, this bias would be eliminated. However, the PBR model can still be implemented in conjunction with other proposed regulatory models and does not need to be a stand-alone option.

Oversight and monitoring

The role of the PUC would change slightly under the HERA model. More specifically, the HERA entity, which will still answer to the PUC, would oversee reliability and grid access functions. In the ISO and distribution-focused model, monitoring and oversight occur across multiple entities, with the Commission delegating market monitoring and competition assessment to the newly created entities. In addition to its current responsibilities, PBR requires the PUC to develop new

PBR mechanisms and determine targets and metrics for assessing the utilities' performance (under the new framework) and from there, create a system of rewards and penalties. Once the PBR mechanism is in place, the PUC must monitor the performance of utilities vis-à-vis the set targets and outcomes.

5.5 Evaluation of the regulatory models relative to state goals

Similar to the ownership models, the Project Team evaluated alternative regulatory models with respect to the policy objectives established by House Bill 1700 (Act 124) of 2016 listed in the text box below.

State's key criteria in evaluating models based on the legislation

- Achieve State energy goals
- Maximize consumer cost savings
- Enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs
- Eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation

Source: House Bill No. 1700 (Act 124) Relating to the State Budget

In its qualitative analysis of the regulatory models, the Project Team relied on the same six major criteria that were used to assess the identified ownership models. The relationship between the four policy objectives and the evaluation criteria was shown earlier in Figure 19. The six major criteria are:

1. ***ability to meet state energy goals;***
2. ***maximize consumer cost savings;***
3. ***enable a competitive distribution system;***
4. ***address conflicts of interest;***
5. ***align stakeholder interests; and***
6. ***assess transition costs.***

Ability to meet state energy goals

As mentioned earlier, the ability to meet state energy goals is explicitly listed as one of the four guiding principles and is a criterion which can be qualitatively assessed. For this criterion, the Project Team focused on Hawaii's target to achieve 100% of its electricity from renewable energy by 2045. The other policy directives are covered by the other criteria. For example, "balancing technical, economic, environmental, and cultural considerations" is reflected in criteria (v): align stakeholder interests. Likewise, "promoting an efficient marketplace that benefits producers and consumers" is substantially similar to enabling a competitive distribution system.

Hawaii's utilities have made significant progress toward the 100% renewables target under the status quo regulatory structure, where the Hawaii PUC maintains oversight of the State's utilities. This indicates that the State's renewable energy goals are potentially attainable under the status quo. All four utilities are vertically integrated and own most of the generation within their territories, with IPPs entering into PPAs with the respective utilities. This centrally controlled structure allows the PUC to push the utilities toward the RPS targets, supported by higher penetration of DERs. The PUC and utilities have encouraged the growth of DERs in Hawaii, particularly rooftop solar, through Net Energy Metering ("NEM") programs and more recently with the Smart Export and CGS+ programs.[153]

Keeping the current structure but increasing oversight of the utilities through a new independent agency such as HERA can further support the achievement of the State's energy targets. One of the main challenges with integrating high levels of intermittent renewable energy on the grid is the maintenance of reliability, which is currently overseen by the utilities themselves and monitored by the PUC. Transferring the enforcement of monitoring responsibility to HERA can prevent or at least minimize the tendency of utilities – under the status quo model – to be more conservative than necessary in integrating renewable resources to maintain reliability. Aside from the need to implement reliability standards across the electric value chain, HERA's mandate also includes providing fair grid access to generators.[154] This can open more opportunities for renewable generators and DER providers. Therefore, the Project Team scored increased oversight by an independent agency more favorably than the status quo model.

The PBR model, if well-designed, is considered to be the most favorable in achieving the State's RPS targets because the PUC can set incentives and penalties explicitly based on progress towards pre-established goals such as "rapid integration" of renewables (including third-party home solar and storage systems), affordable rates, electric reliability, and customer choice and satisfaction (specific PBR metrics can be set for any of these criteria). The PBR model scores very favorably because it enables a "carrot and stick" approach that can be designed to both encourage utilities to achieve targeted performance and penalize them for underperformance. It also allows the utility freedom in optimizing its resources given targets and objectives.

The ISO and distribution-focused regulatory models both score less favorably than the status quo because they fail to address incentives at opposite ends of the generation spectrum. The ISO model can facilitate the development of significant renewable projects by increasing competition at utility-scale. As an independent body, system planning conducted by an ISO would also level the playing field between generators and allow renewables to compete based on cost and value to the grid. On the other hand, an ISO model without new initiatives at a distribution level will

[153] The Smart Export and Customer Grid Supply + ("CGS+") programs allow customer sited solar generation to supply power to the HECO companies at fixed rates. The Smart Export program allows up to 3,500 to 4,500 customers to export energy through their solar-battery system to the grid during evening, overnight, and early morning (i.e., 4:00 PM to 9:00 AM) following charging during the day. The CGS+ program allows approximately 5,000 to 6,000 customers with solar PV-only systems to export energy to the electric grid during the day (Source: Hawaii Public Utilities Commission).

[154] Hawaii Senate Bill 2787 (2012).

not substantially expand opportunities for DERs to participate. Conversely, a distribution-focused model can support the growth of DERs by unlocking additional value for them by incorporating them into distribution-level planning, allowing them to provide grid services and facilitating direct transactions with other customers. However, such a model does not address generation (at utility-scale), which accounts for most of the generation.

Maximize consumer cost savings[155]

As discussed earlier, maximizing customer cost savings is also one of the four major criteria and can be assessed from both a qualitative and quantitative perspective. Hawaii's customers already pay the highest rates for electricity in the US. The average electricity price across all sectors in 2016 was 132% higher than the national average and 33% higher than the next most expensive state, Alaska.[156] Ratepayers bear several categories of costs that are impacted by regulatory structures, including (but not limited to): (i) power supply including fuel costs; (ii) other utility operating costs; (iii) costs of regulatory proceedings; (iv) fees to fund regulatory bodies such as PUC (and HERA, if implemented); and (v) return on capital investments.

Regulatory models can lower the costs faced by customers if they can support the development of lower cost resources for generation, reduce reliance on expensive imported oil, incentivize the utility to be more efficient and cost-effective in its operations, lower the regulatory burden (including the length of typical regulatory proceedings), or reduce the bias for utilities to favor capital expenditure for higher returns.

The PBR model is regarded as the most favorable in terms of reducing costs to consumers in the long run because it can incorporate incentives to control costs under both price- and revenue-cap approaches, while still maintaining service quality as well as other parameters set by the PUC. It can also set incentives that de-emphasize the importance of returns on capital investments for utilities' profitability. Indeed, in its order instituting the PBR proceeding, the PUC outlines its interest "in ratemaking elements and mechanisms that result in:"[157]

- greater cost control and reduced rate volatility; and
- efficient investment and allocation of resources regardless of classification as capital or operating expense.

It is important to note that establishing PBR will initially require time and impose a sizable regulatory burden on both utilities and the PUC, the costs of which will be passed on to ratepayers. However, once implemented, this model can achieve reductions in multiple categories of costs, creating higher savings for consumers in the long run.

[155] The consumer cost savings considered in this section exclude consideration of implementation costs, which are treated separately.

[156] EIA. *Electric Power Annual 2016.* Revised May 2018.

[157] Hawaii PUC. *Docket No. 2018-0088 Instituting a Proceeding to Investigate Performance-Based Regulation.* Order issued and effective April 18, 2018. page 52.

An ISO model can also lower the costs of the power supply by increasing competition in generation. Likewise, independent transmission planning and operations can lower system-wide costs. It also addresses utility bias towards capex, at least at the transmission-level, because utilities will make investments based on the ISO's planning. This is a more favorable environment for lowering costs to consumers than the status quo, where the utilities have no incentives to minimize costs due to the cost of service ratemaking regime. Costs to consumers are controlled in regulatory proceedings, such as rate cases, by the PUC and the Division of Consumer Advocacy ("DCA"); however, COS regulation has been observed to provide an incentive for utilities to overstate capex (to increase returns on investments), subsequently and possibly resulting in higher costs.

The regulatory burden could increase for utilities in a HERA model, as they will have to monitor and track various metrics on reliability and grid access. Furthermore, the HERA entity will have to be staffed with trained personnel to enforce standards and ensure utility compliance. There will also be an additional reliability surcharge on ratepayers to fund HERA.

A distribution-focused regulatory model is the least likely model (at present) that can reduce costs (in the short term) to consumers. Such a model requires extensive investment in grid-modernization technologies. Some of the technologies needed for a fully-fledged version of this model have not been operationalized outside of pilot tests. The enabling technologies, both hardware and software, may improve capability and become cheaper over time. The full costs of transition to a distribution-focused model are largely unknown, but they are likely to be high based on prevailing market conditions. These costs will eventually be passed on to ratepayers.

Enable a competitive distribution system

Enabling a competitive distribution system is the third guiding principle and can be assessed on a qualitative basis. A competitive distribution system is one "in which independent agents can trade and combine evolving services to meet customer and grid needs."[158] This goal requires the evolution of grid operations and services away from the traditional utility business model where the utility has a monopoly over the sale of electricity and other limited services to the customer. The traditional regulatory models are not as favorable for a competitive distribution system as more innovative ones.

The Status Quo offers programs like Smart Export and CGS+ to expand rooftop solar and battery storage. However, this approach limits the competitiveness at the distribution level because the utility remains the sole buyer of electricity from distributed generation, excluding any separate bilateral contracts between independent parties. Technology providers can offer their services to utilities as well as customers. Utilities increasingly partner with third-party companies, especially because of their need for software and other services that support grid management. For example, HECO is using Opus One's GridOS Dynamic Hosting Capacity software to understand how many DERs can be integrated into a distribution feeder to better optimize grid assets in real-

[158] Hawaii Contract No. 65595. Scope of Services.

time.[159] Customers can also purchase products and services (like the Nest thermostat and similar home energy management systems) from third parties. However, such opportunities for customers and other market participants are defined by the utility through scope, requirements, and rates.

Adding increased oversight is slightly more favorable than the Status Quo. Independent planning by an entity such as HERA can address the tendency of utilities to limit the participation of DERs and service providers, for example, by using excessively stringent criteria. HERA's responsibility to oversee grid access can ensure that grid-services provided by DERs[160] are integrated into planning without impacting reliability.

The ISO model is regarded as more favorable than the status quo models because it enables greater participation of DERs at the wholesale level. For example, FERC Orders 745 and 841 have opened additional opportunities for demand response and energy storage to participate in wholesale markets and be compensated appropriately in other North American jurisdictions. Under the ISO model in other jurisdictions, DERs can compete with generation and even transmission upgrades in meeting system needs.[161] Utilities in markets with an ISO have begun to deploy DERs as a non-transmission alternative to defer or even replace the need for transmission upgrades. The independence of ISOs is critical to ensure that the competition is not biased in favor of utility-owned generation or new transmission projects with high capex.

Likewise, the PBR model can be more favorable than status quo models because of the incentives and penalties that can be designed based on the criterion: increasing competition at the distribution level. New York is pursuing a version of this by soliciting innovative solutions with various features including Advanced Metering Infrastructure ("AMI") network access, customer response to smart home and time-of-use rates, Energy Marketplace 2.0, increasing hosting capacity, reducing peak, and Non-Wire Alternative ("NWA") projects.[162] Incorporating Earnings Adjustment Mechanisms ("EAM") in the PBR framework can be favorable for a competitive distribution system because utilities have incentives to increase participation of third-party

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[159] "Hawaiian Electric and Opus One Collaborate on Grid Modernization." *Opus One Solutions*, 18 April 2018. Web. Accessed on May 17, 2018. <www.opusonesolutions.com/news/hawaiian-electric-and-opus-one-collaborate-on-grid-modernization>

[160] According to a survey of literature on benefit-cost analyses of behind-the-meter resources conducted by eLab, DERs can provide grid support services (in addition to energy and capacity) such as reactive supply and voltage control, regulation and frequency response, energy and generator imbalance, and synchronized and supplemental operating reserves.

[161] Only California's market, operated by CAISO, allows aggregate DERs to participate in the wholesale market, in both the energy and ancillary service markets. This take the form of a DER provider ("DERP"), a market participant allowed to aggregate DERs to meet the 0.5 MW requirement to participate. Examples of DERs that can participate under this market arrangement include generation such as rooftop solar PV, energy storage, plug-in electric vehicles ("EV"), and demand response (Source: CAISO. *Distributed energy resource provider.* <http://www.caiso.com/participate/Pages/DistributedEnergyResourceProvider/Default.aspx>)

[162] "Innovation Opportunities." *REV Connect*, Accessed on May 17, 2018. <nyrevconnect.com/innovation-opportunities/>.

service providers. The EAMs and solicitation of innovation opportunities, as designed in New York's REV, may help align utility incentives and increase competition at the distribution level. However, it retains a centralized approach to procurement, which could undermine initiative and creativity. New York's efforts with NWA programs and EAMs are considered transitionary steps toward a fully-fledged distribution-focused regulatory model, conceptualized as a DSPP.

A DSPP or IDSO model can be the most effective model in enabling a competitive distribution system because customers, DER providers, and service providers can transact with each other in the future under this model without the utility serving as an intermediary or defining solicitation criteria. Compared with other regulatory models, a distribution-focused model allows buyers and sellers of energy and other services to interact directly with each other. Such increased transparency can encourage more participation in distribution markets. In New York, utilities can earn platform service revenues, which are tied to the selling of products and services that facilitate distribution-level markets, shared revenue opportunities, and other options for customers (such as the ability to pay a fee for value-added services such as advanced data analytics).[163] If a similar mechanism is instituted in Hawaii, utilities would have a stronger incentive in facilitating the growth of distribution-level markets than solely under a PBR model.

Address conflicts of interest

Addressing conflicts of interest is the fourth guiding principles and can be evaluated on a qualitative basis. Conflicts of interest can take place between and among utility shareholders, ratepayers, regulators, and market participants like IPPs and DER providers in matters of energy resource planning, delivery, and regulation. Addressing conflicts of interest requires as much separation of planning and operational control from investment and ownership as possible. The performance of various regulatory models in addressing conflicts of interest has been discussed in the previous three criteria and will be summarized again in this section.

The status quo model is the least favorable because the PUC is the sole entity responsible for addressing or managing conflicts of interest. The utility maintains full control of energy planning and delivery with PUC oversight being the only check. This means that there is information asymmetry between the utility and the regulator, i.e., only the regulator has access to as much information on the utility's actions as the utility provides. Increasing oversight with HERA can help spread the regulatory burden between agencies. The independent planning can also help address utilities' potential conflict of interest against IPPs and DERs, for example, by separating some system planning functions. A PBR model can use incentives and penalties to align the utilities' business models—a step, which helps in guarding against or managing conflicts of interest—but it will not result in full separation of planning and operational control from investment and ownership. Such a separation is achieved by a distribution-focused regulatory model at the distribution level and an ISO model for the transmission system and utility-scale generation. Combining both an ISO and a DSPP/IDSO model would be most effective in addressing conflicts of interest.

[163] Ibid.

Align stakeholder interests

Aligning stakeholder interests focuses on whether all stakeholder (PUC, CA, Legislature, Utility, and Consumers) incentives are aligned, rather than whether conflicts can be resolved.

The status quo model is, again, the least favorable because shareholder returns are driven by capital expenditures, which could potentially lead to increased spending and higher rates, whereas ratepayers want to keep their electricity rates low. This conflict plays out through other channels as well. Ratepayer interests could favor greater participation of DERs and IPPs if it can help keep their costs low. This would harm utilities' profitability unless they could increase capex in grid modernization infrastructure to accommodate more DERs—a step which could negate the potential cost-reduction value of DERs depending on the implementation. Increasing oversight of the status quo along with the accompanying independent planning could better align interests between ratepayers and utilities.

A distribution-focused regulatory model is more favorable than the other models in this criterion because utilities are focused on providing the necessary level of distribution infrastructure. An IDSO is perceived as more fair than the status quo utility because it has no incentive to increase its profitability beyond what is needed to keep it financially healthy. Likewise, the ISO maintains similar independence in transmission planning and operations—a feature, which would help increase competition in utility-scale generation. Furthermore, either an ISO or IDSO would both align the interests of ratepayers, utilities, and market participants.

However, a PBR model, if designed correctly, is the most favorable of all the regulatory models in this parameter because there are multiple avenues where stakeholder interests may be aligned (e.g., through incentives). Incentives based on shared savings can be designed to both decrease capex spending and increase operational efficiency, resulting in lower rates while aligning interests with the utility. Likewise, other incentives based on RPS achievement, DER interconnection, and similar programs benefit both ratepayers and utilities. The incentives and penalties in a PBR model are determined in regulatory proceedings in which stakeholders can intervene, allowing both ratepayers and utilities to provide their inputs.

Minimize the transition process and costs

The additional criterion proposed by the Project Team is the transition cost. The "maximize consumer cost savings" criterion compares the regulatory models based on cost savings for consumers *after* the transition has been completed. It is essential to look at the steps needed to move to a new regulatory model to understand the level of opposition and delays that the process may encounter, all of which can substantially increase the transition costs.[164] The more stakeholders involved in the transition process and the more approvals required indicates a greater probability of delays. Likewise, it is essential to consider if a new regulatory model will require divestment of assets by the utility. This can increase the opposition of the utility and the likelihood of an expensive litigation process as well as lengthening the timeframe required to sell assets.

[164] Task 2.3.1 discussed this in detail.

Increased utility oversight through a HERA entity would be the least burdensome alternative regulatory model with respect to transition costs and timeframe. The law that requires the establishment of HERA already exists through state legislation (Act 166) in 2012. There will still be costs in setting up HERA as a functioning organization. The PUC is authorized to contract with a person, business, or organization (except a public utility) for the performance of HERA's functions.[165] Therefore, it must set the requirements for interested entities and run a competitive solicitation. Furthermore, there may be additional costs in hiring the personnel with the necessary expertise and/or providing additional training to the new staff. While this process must be conducted thoroughly, there are no glaring pitfalls that could result in lengthy stakeholder outreach or expensive litigation.

Compared to the move to a HERA model, the move to a PBR model could be a lengthy and expensive process, especially during the first regulatory period, despite the recently enacted legislative mandate. PBR has several "flavors"—ranging from "light" to "comprehensive" mechanisms—and involves price- vs. revenue-cap approaches (as discussed in Section 5.1.4.). Moreover, several criteria can be linked to performance targets. The exact combination of various components of PBR can result in substantially different incentive/risk profiles and revenue opportunities for the utility. For first-generation PBR, there will also be costs related to the hiring of external consultants and experts (who can guide designing PBR proposals) by both the PUC and utilities. The length of the process for deliberation (e.g., between proposed PBR models), incorporation of stakeholder feedback, and finalization of the ultimate design could take between several months to more than a year.

An ISO model is even less favorable in terms of transition costs because it requires the actual purchase of physical equipment in addition to the establishment of a new organization. First, there may be a need for legislation (toward the creation of an ISO) after due process and deliberation. This can be a lengthy process itself due to the need for extensive stakeholder engagement. There must also be a clear demarcation of authority between/among the new ISO, utilities, and the PUC.

Furthermore, the establishment of the organization requires defining of clear governance structures, the hiring of appropriately qualified staff (both from current utilities and externally), and the establishment of the office. It will require separate premises and office infrastructures such as computers, IT infrastructure, and furniture (some of which might come from the utility and some purchased). The specific software and equipment used by the current utilities for system planning, dispatch, and day-to-day operations can be obtained from the utilities themselves.

The distribution-focused regulatory model is regarded as the least favorable due to the extent it varies from the current utility business model, the infrastructure needed to enable it, and the degree of unknown costs. As with the ISO model, legislation that supports the move to a distribution-focused model should first be passed, but such a law requires an extensive

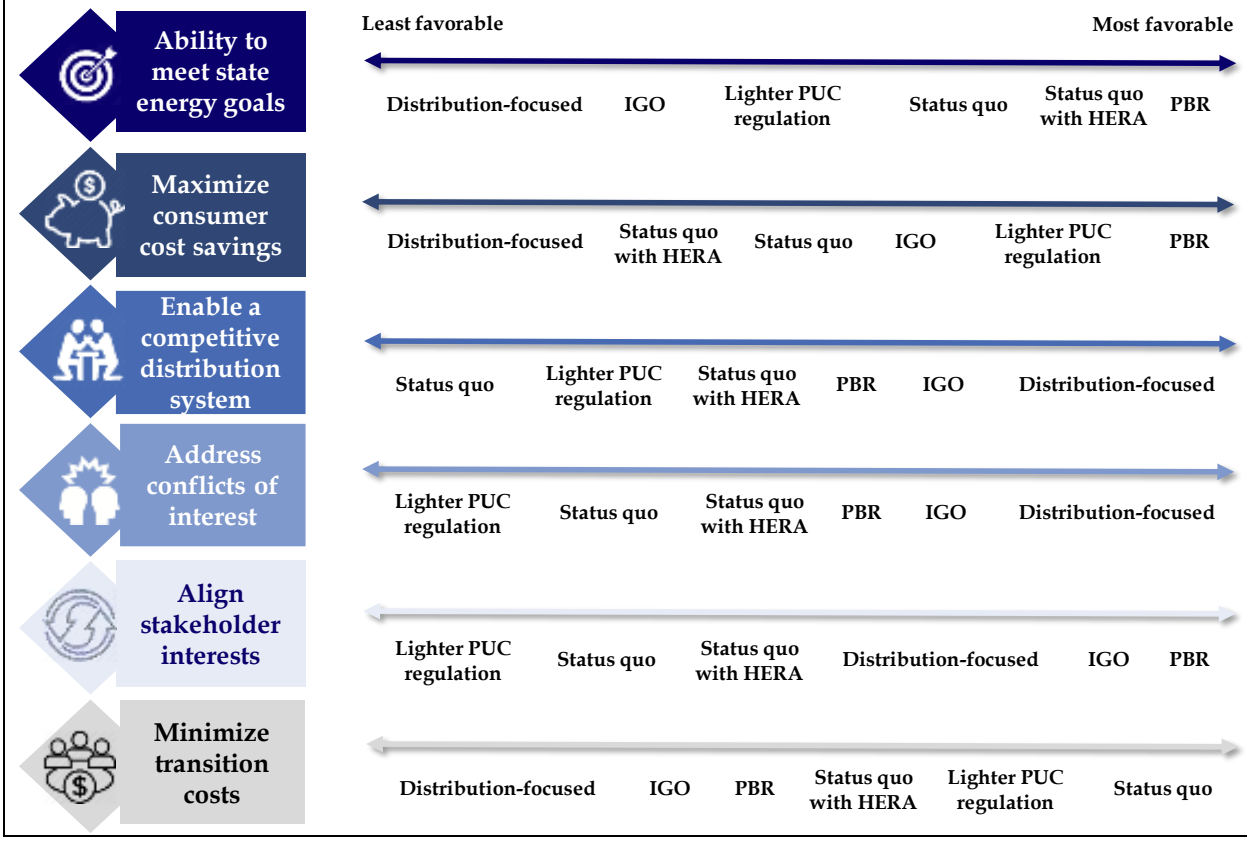
[165] HRS 269-147.

stakeholder engagement process. However, while there are several examples of well-functioning ISO markets, the same cannot be said of an IDSO or DSPP market.

Summary evaluation of regulatory models relative to the criteria

The high-level results of the Project Team's qualitative evaluation of the six regulatory models described previously with respect to each of the six ranking criteria are summarized in Figure 38.

Figure 38. Evaluation of regulatory models relative to the ranking criteria



Among the regulatory models considered for this Study, the PBR model ranked the highest while the Status Quo ranked the lowest. The PBR model scores very favorably because it enables a "carrot and stick" approach that can be designed to both encourage utilities to achieve targeted performance and penalize them for underperformance. It also allows the utility freedom in optimizing its resources given targets and objectives. In contrast, the Status Quo performed less favorably due to a misalignment of incentives – IOUs have incentives to favor capex spending over other types of solutions and but not to pursue efficiency improvements.

The combination of incentives and penalties enables PBR to perform most favorably in terms of meeting State energy goals, lowering costs to consumers, and aligning stakeholder interests. It could also include mechanisms like the price- or revenue-cap to control costs.

PBR also represents an improvement with respect to the Status Quo in terms of enabling a competitive distribution system or addressing conflicts of interest. For both criteria, other models create a new structure that helps to achieve those goals more effectively. However, appropriate mechanisms and design elements under PBR could still help advance those goals.

Figure 39. Most favorable model for each evaluation criterion

Criteria	Most favorable model
Meet state energy goals	PBR
Lower costs to consumers	PBR
Enable a competitive distribution system	Distribution focused regulatory model
Address conflicts of interest	ISO/Distribution focused regulatory model
Align stakeholder interests	PBR
Minimize process and transition costs	Status quo

5.6 Combining regulatory models

Analysis of the state criteria showed that combining some of the regulatory models would be more effective in facilitating the achievement of the state goals. More specifically, the PBR model could be designed to be effective alongside an ISO and DSPP/IDSO (collectively an Independent Grid Operator or "IGO"), or under additional HERA oversight. Combining PBR with an IGO could even be more effective than a standalone PBR in meeting the State's goals, except that this would lead to higher transition costs.

Combination of the Conventional PBR and a Light HERA

A combination of the Conventional PBR and a Light HERA could be able to help achieve most of the state goals discussed in the previous section. More specifically, this hybrid model could lower costs to consumers in the long run due to the indexing formula of the Conventional PBR. Since revenues are fixed, utilities are incentivized to be more efficient in their expenditures while still achieving their mandated targets. Combining this with the Light HERA will also lower costs as the HERA entity will provide a fair interconnection process, where third-party power providers can compete with the utility in offering the most cost-effective solutions.

This combined model could also enable a competitive distribution system as HERA manages the DER interconnection process in a fair and transparent manner. Adding Light HERA to the regulatory regime would simplify the monitoring of the DER interconnection process (including associated reliability and hosting capacity analyses) by moving these tasks to an independent body. DER interconnection requests would be prioritized based on how beneficial they are to the overall grid rather than to the utilities' bottom line. Moreover, conventional PBR with revenue caps can encourage utilities to support the growth of DERs. The support would be driven by the totex approach to calculating revenue requirement, increased ease of interconnection for DERs and better designed PIMs.

Conflicts of interest would also be minimized or reduced because HERA functions as an independent appeals body that can help settle differences. The combination of the Conventional PBR and Light HERA aligns stakeholder interests because PIMs can be designed to address

stakeholders' concerns. Process and transition costs can be lower in the long run. For instance, there will be fewer rate filings because of the fixed PBR regulatory term, and a litigation process that allows HERA to act as the ombudsman tasked to assist in settling differences between the utility and customers (e.g., on issues related to interconnection and hosting capacity).

The Light HERA entity also frees up the utilities' resources, so they could focus primarily on improving efficiencies and lowering costs. This has the potential to deliver the more significant benefits that are usually found in the Conventional PBR model. Moreover, both components of this combined regulatory model are already being implemented in other jurisdictions. Therefore, lessons learned from their experience can be considered in designing these regulatory models. Likewise, there is already legislation for a HERA in Hawaii; no further legislation would be required for a Light HERA entity.

Hybrid Model: Combination of an Outcomes-based PBR, DSPP, and ISO/IDSO ("IGO")

Another combination that could achieve most, if not all, of the state goals, is the combination of an Outcomes-based PBR, DSPP, and ISO/IDSO. As mentioned earlier, given the smaller size of Hawaii's transmission systems (compared to jurisdictions elsewhere), the Project Team believe that combining the functions of the ISO and independent IDSO is more effective and efficient in the Hawaii context. The Project Team refers to this combination as an IGO. The responsibility of planning and operations, including the dispatch of both the transmission and distribution system, falls to the IGO. It would also determine the investment requirements of both transmission and distribution networks. The utilities would continue to own the transmission and distribution assets, but the operations would be under the IGO.

The role of the utility would also evolve into that of a DSPP. Under the IGO's oversight, the utilities can establish guidelines for DERs and other service providers so that they can offer grid support services. Utilities can then run competitive solicitations for these services and would only be allowed to provide these services themselves if third-party providers failed to beat the utilities' cost benchmarks. The IGO's independence will help ensure that the evaluation criteria for such solicitations will not be designed to favor any potential offeror, including the utility deliberately. Utilities and IGO can devise a compensation scheme for these services such that ratepayers would bear lower costs compared with instances (under the previous model) when they rely on traditional utility solutions (such as infrastructure upgrades). Utilities will also be allowed to earn additional revenues, either as shared savings from avoided costs to ratepayers or as fees from the third-party providers ("platform revenues," for example).

The components of this Hybrid model can be implemented in different stages. The hybrid regime will feature Outcomes-based PBR initially—the IGO's functions such as the overseeing of reliability and interconnection and the DSPP's role in leveraging DERs for grid services (to lower costs to ratepayers) can be incorporated as outcomes and metrics within the PBR framework. When the IGO is introduced, reliability and interconnection targets can be removed from utility ratemaking. It may be prudent to add the DSPP component last, or at least not before the IGO, as it is the most complex component and the intervening years can shed more light on the enabling technologies and business models.

Indeed, it may even be more advantageous to implement such a combined model. The proposed hybrid model would likely be more effective in meeting the State's goals. It would be more effective in enabling a competitive distribution system and addressing conflicts of interest than just a "pure" PBR model. Furthermore, fewer incentive mechanisms would be necessary under such a hybrid model because the IGO and the utilities' role as a DSPP would make it unnecessary to include incentives (such as for those related to reliability, DER interconnection, or competitive procurement) for the utility. In such a scenario, the proposed IGO would likely address those criteria by its independence and mandates. Therefore, the focus of the incentives under PBR can be directed to where they will be most effective, for example, on lowering costs and aligning the utility's incentives with the State's energy goals.

A staggered implementation could also help lower the transition costs of this Hybrid model and make it more predictable. The costs of a DSPP model will be better understood because lessons from other jurisdiction regarding implementation, technology, and business models can be adapted to Hawaii. There is more time to conduct the necessary analyses, so the State can fully understand all costs and benefits and ensure that it is implemented correctly. The additional time can also allow the completion of any needed legislative processes.

Task 2.2.1 *(High-level evaluation of the regulatory models relative to the State's goals)* discusses this in detail.

5.7 Potential stranded costs

In the case of regulatory models where assets remain regulated (such as the Status Quo and PBR), there would not be stranded costs related to the change in the regulatory regime. Since the utility assets, or rate base assets, were procured under the oversight of the PUC, the acquisitions are presumed to be reasonable and necessary to the continued reliable operation of the power grid in each county.[166]

On the other hand, for the other regulatory models such as the IGO and DSPP, the utility could be encouraged to transfer or divest certain classes of assets, mostly related to generation, to an unregulated subsidiary or IPPs. Should a change in regulatory model require the transfer or divestment of certain classes of utility assets, the transfer price would presumably follow a competitive process where multiple interested parties would bid to purchase either part of or the entire portfolio of utility assets that are being divested. If the assets become unregulated, or "merchant," the acquiring entity would purchase the assets at a price that allows it to recover its costs and earn its desired return on investment, given the expected magnitude of market revenues. Stranded costs arise if the market value of assets the utilities must divest, such as generation resources, is lower than their book value. Historically, provided that the investments were prudent and verifiable, utilities have been allowed to recover stranded costs from ratepayers. The Project Team estimated the potential stranded costs for utility generation assets in the State, as illustrated in Figure 40.

[166] There may be stranded costs at the time the assets are retired if not fully depreciated, but these costs would not be caused by the change in regulatory regime but rather by the evolution of the generation resource mix.

These stranded costs calculation is indicative, as the magnitude of actual stranded costs may differ due to a variety of factors such as:

1. market risk vs. regulatory certainty for acquiring entity;
2. the higher cost of equity for merchant entities than regulated ones;
3. potential buyers having more bearish views on market conditions; and
4. single asset vs. portfolio purchase.

Figure 40. Potential stranded costs for utility generation assets in the State of Hawaii

Utility	Potential Stranded costs
HECO	$321.9 million
HELCO	$12.5 million
MECO	$11.3 million
KIUC	$31.9 million

In addition, all options considered assume that transmission and distribution assets would remain regulated and as such would not be a source of stranded costs for the incumbent utilities should there be a change in the regulatory regime.

Task 2.2.4 *(Summary analysis and conclusions related to estimating stranded costs for each regulatory model)* provides a more detailed discussion on potential stranded costs from a change in regulatory model.

5.8 Feasibility of the regulatory models

Similar to the process in the ownership models, the Project Team conducted a high-level technical, financial, and legal feasibility of each regulatory model. Based on the technical feasibility analysis, all models should be able to comply with service, quality, and reliability standards, with an independent monitor or the Commission itself enforcing standards. Moreover, three of the assessed models—the HERA, IGO, and distribution models — require the creation of new entities. The PUC would play a pivotal role in defining the mandate and scope of these new entities.

Furthermore, the regulatory models differ in their ability to facilitate the achievement of the State's energy goals. The PBR model could be designed to incentivize achievement of the State's goals directly through the PIMs, while incorporating all of the State's broader policy goals within an IGO construct may limit potential efficiency gains. The HERA model is limited by its legislatively mandated scope (on reliability) while the DSPP model is promising but carries a high level of implementation risks.

When it comes to financial feasibility analysis (for most models), the financial requirements for the implementation of each model vary significantly by model. The IGO and DSPP models likely require the most significant investments to create and fund the new IGO entity. IGO costs could be higher if independently implemented on each island. The costs associated with the implementation of PBR will be the result of an intensive regulatory process before the PUC to create new mechanisms. HERA funding will be secured via a legislative mandate, but the magnitude of costs would still vary depending on the ultimate scope of HERA's mandate. The financial impact of each model on ratepayers, therefore, varies for each model, with implementation costs driving impact to customers.

Meanwhile, the legal framework for the successful implementation of the models represents a barrier, especially for the IGO model, which will likely require new legislation before its implementation by the PUC. The PBR and HERA models do not require enabling legislation since both are already authorized by Hawaii State law but would still require a PUC investigative docket or rulemaking proceeding before implementation. As of this writing, the PBR docket is underway. The DSPP model would not require new legislation, but it may still be helpful for practical reasons to have legislation that would provide the PUC with the authority to define a new utility business model and new roles for stakeholders. Moreover, there are several legal issues that should be addressed during the implementation of the models. These include determining the status of existing PPAs, fuel purchasing contracts, and reassuring the financial viability of prior investments (e.g., the need to ensure a reasonable return for prudently made investments by utilities during previous regulatory regimes).

Task 2.2.3 *(High-level assessment of the technical, financial, and legal feasibility of each regulatory model)* discussed in detail the results of the high-level feasibility review.

5.9 Views of the stakeholders

Location of the community outreach

- City and County of Honolulu
  - Honolulu
  - Kailua
- Hawaii County
  - Hilo
  - Kona
- Maui County
  - Lanai City, Lanai
  - Wailuku, Maui
  - Kaunakakai, Molokai
- Kauai County
  - Lihue

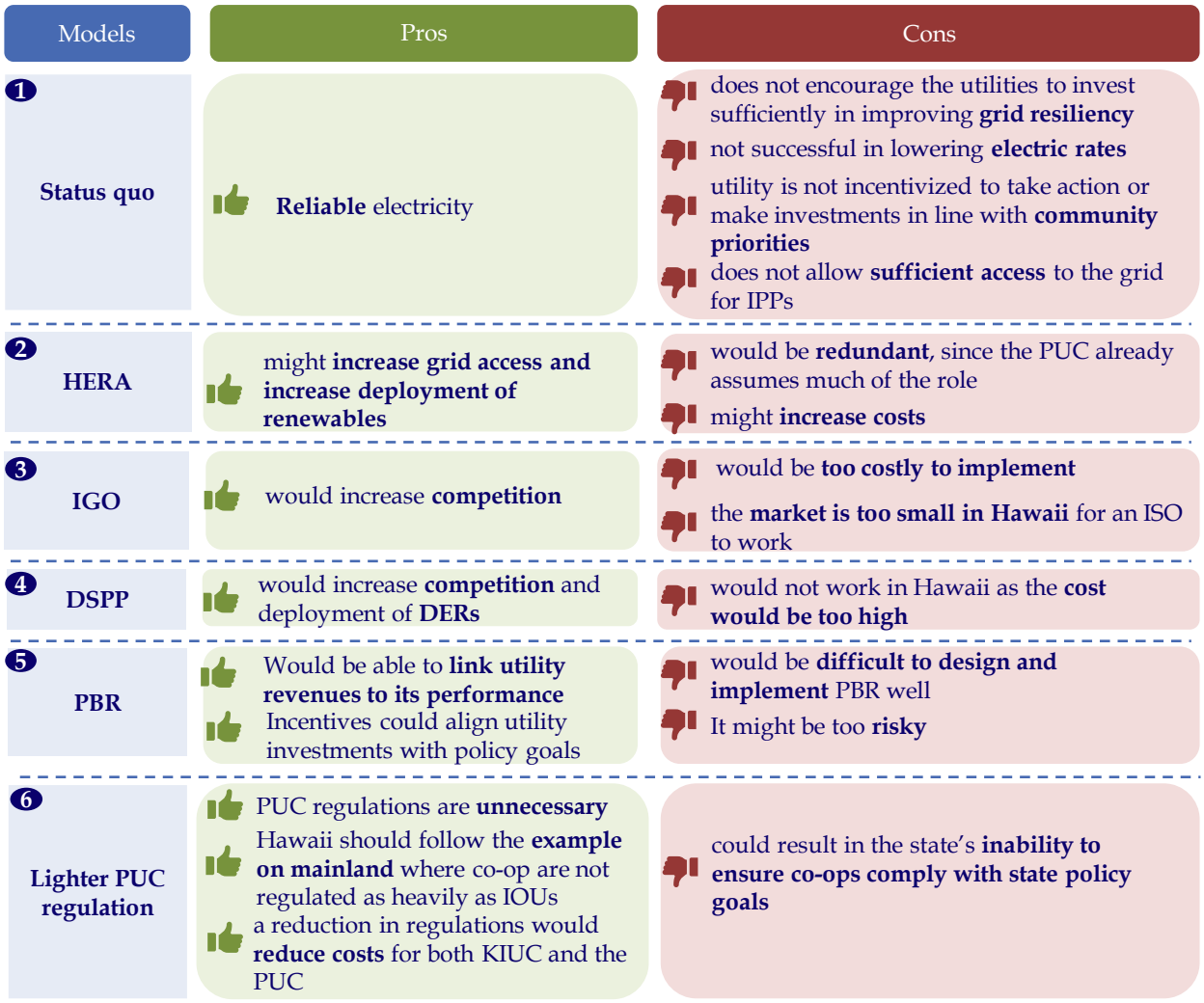
The Stakeholder Workshops for the Utility Regulatory Models were completed between June 13, 2018, and June 22, 2018. There were eight (8) public workshops held at each location shown in the textbox on the left. Additionally, the Project Team conducted a workshop at the VERGE conference in Honolulu on June 12th, 2018.

The objectives of the workshops were to provide stakeholders with information regarding the various regulatory models under consideration as well as to receive their input on the priorities for the regulation of the electric sector, and their input on the advantages and disadvantages of different regulatory

models in meeting community priorities. Combined, 75 stakeholders participated in the public workshops, and more than 100 participated in the workshop at VERGE.[167]

In addition to the workshops, multiple bilateral meetings were held as part of the ongoing stakeholder engagement process. Between June 12th and June 22nd, the Project Team met with 20 energy industry, government, non-profit, and other stakeholders from across the state and received input that varied from support for PBR implementation, to interest in only minor revisions to the Status Quo, to concern for unintended consequences due to the difficulties in designing PBR well, to support for Lighter PUC Regulation of co-ops. The main takeaways of the outreach effort are summarized in Figure 41.

Figure 41. Summary of pros and cons of each regulatory model according to the participants of the community outreaches



[167] The majority of participants at VERGE did not sign in.

London Economics International LLC
717 Atlantic Avenue, Suite 1A
Boston, MA 02111
www.londoneconomics.com

All participants to the community outreach agreed that the current regulatory model results in the provision of reliable electricity to the state. There was a general concern in relation to the HECO Company utilities, however, that the status quo does not encourage the utilities to invest sufficiently in improving grid resiliency. Across the state, participants believed that this model has not been successful in minimizing electric rates. In general, stakeholders did not think that HERA would be a good solution for Hawaii. While many noted that it might increase grid access and increase deployment of renewables, a majority of stakeholders thought that HERA would be redundant, since the PUC already assumes much of the role HERA would be playing and would ultimately increase overall costs.

Though it was recognized that an IGO would increase competition, stakeholders felt that it would be too costly and that the market is too small in Hawaii for an IGO to work.

Participants' opinions varied greatly regarding a DSPP model. While many argued that this model would not work in Hawaii, others saw it as a way to increase competition and deployment of DERs. Many stakeholders mentioned that the costs would be too high, particularly the necessary up-front investments required to implement this model.

Participants were supportive of using incentives under a PBR framework to encourage utilities to make investments and take actions that are in line with community and policy goals. The potential metrics discussed significantly varied and included cost stabilization, cost equity, increased renewable generation, incorporation of community priorities, the reliability of service, and grid resiliency. Multiple stakeholders suggested that it would be critical for representatives from each island to be involved in designing the metrics. There was general agreement that linking utility revenues to performance would be beneficial. Nevertheless, many stakeholders highlighted that it would be difficult to develop and implement PBR well, and there was substantial concern about unintended consequences that would result if it is not designed well. As a result, some stakeholders explained that it might be too risky. Preferences varied from a PBR model that would create minor adjustments to the status quo to one that would result in a significant overhaul of the system.

There was broad support for Lighter PUC Regulation of co-ops, mainly from stakeholders on Kauai. Many stakeholders said that the KIUC has demonstrated the ability to manage and operate the utility well and that PUC regulations are unnecessary. Some stakeholders suggested that Hawaii follow the example on the mainland where co-ops are not regulated as heavily as IOUs. Stakeholders on Kauai felt that a reduction in regulations would reduce costs for both KIUC and the PUC.

Task 2.2.5 *(Outreach Plan and documentation of results of public outreach)* documents the views of the participants to the community outreaches for the regulatory models.

5.10 Regulatory models selected for further review for the HECO Companies

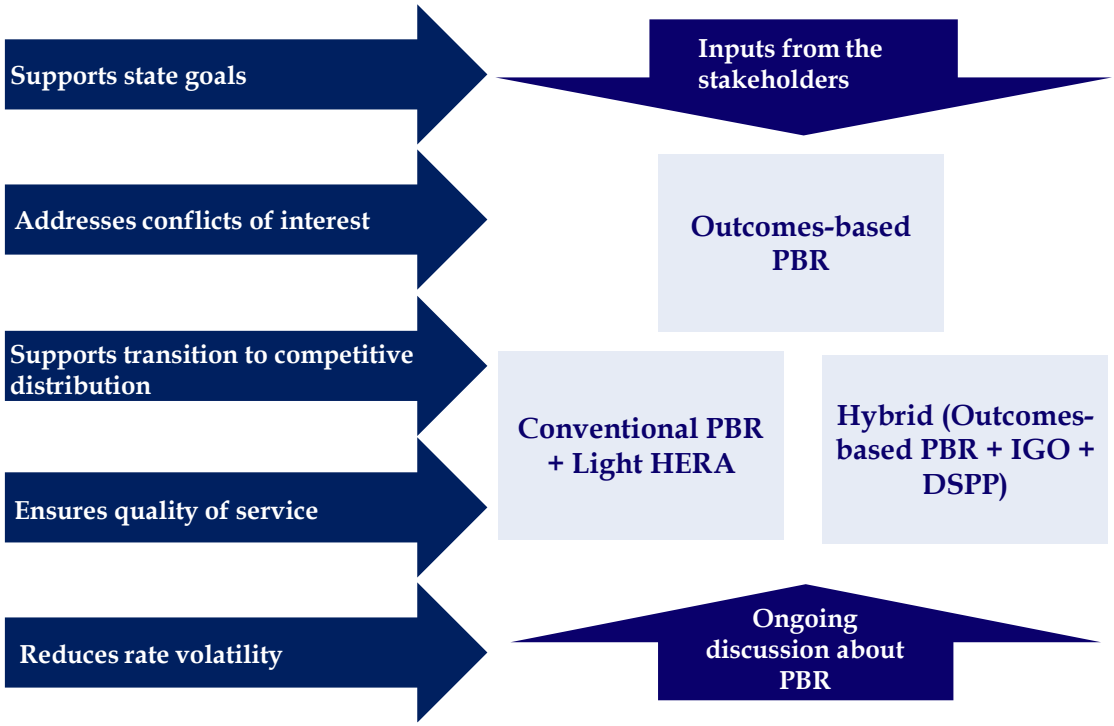
The analysis identified the most beneficial regulatory models for counties currently operating under an IOU for further study relative to the Status Quo in the succeeding tasks. These models are:

1. Outcomes-based PBR model;

2. Conventional PBR with Light HERA model; and
3. Hybrid model.

The regulatory models were assessed based on the State's key criteria. The evaluation also considered input from industry stakeholders and community members received during the outreach held in June 2018, and the fundamental expectations of the utility.

Figure 42. Factors considered in choosing the regulatory models for further study (for Hawaii, Honolulu, and Maui counties)



The Hybrid model scored similarly to the Outcomes-based PBR model in some criteria but was considered more favorable in terms of its ability to facilitate the achievement of State energy goals. The IGO helps to address conflicts of interest and ensure impartiality in the interconnection of generation and reliability analyses, while the DSPP component supports a transition to a competitive distribution system. Although the transition costs and the likelihood of legal challenges for this model are higher (hence, it scored less favorably than the standalone model in this respect), a staggered implementation of the different components (as described in Section 5.5) could ensure lower upfront costs and ease the transition. Once implemented, the DSPP and IGO components would also reduce the administrative burden of a PBR regime (i.e., by taking on some of the responsibilities enshrined in PIMs).

In summary, the Hybrid model scored highly for all the specified criteria and also would meet the PUC's goals of achieving:[168]

1) greater cost control and reduced rate volatility;
2) efficient investment and allocation of resources regardless of classification as capital or operating expenses;
3) fair distribution of risks between utilities and customers; and
4) fulfillment of State policy goals.

The analysis also showed that the Outcomes-based PBR model is well-suited to the State context even as a standalone model. An expanded set of PIMs and a longer regulatory term offers greater flexibility and benefits compared to the other PBR models. However, this model of PBR has not been implemented as widely as Conventional PBR, nor is it as familiar to the State of Hawaii's stakeholders as the Light PBR. Consequently, the design and implementation of an Outcomes-based PBR would involve more data collection, analyses, and monitoring requirements, likely leading to higher implementation costs.

The combination of the Conventional PBR with Light HERA also ranked favorably in the review. It did not score as highly as the two Outcomes-Based PBR models in the first major category (support for State policy goals). However, the scoring indicates that this model would be useful in keeping rates stable. It also scored well across the board in the other major and minor categories. Task 2.2.6 (Identification and recommendation for the three most beneficial regulatory models for further consideration) provides a more detailed discussion on the scoring for this model.

5.11 Regulatory models selected for further review for Kauai County

A separate analysis conducted for Kauai County suggests the three most beneficial regulatory models for Kauai County are:

1) HERA model;
2) IGO; and
3) Lighter PUC Regulation.

The HERA model ranked favorably given the regulatory model's potential to support the State policies, strengthen the utility's performance, and its legal viability. Under this model, KIUC would maintain its current structure as a co-op. Its member-owned structure can intrinsically align interests between ratepayers (or the interests of the majority) and the utility. It has access to subsidized debt that allows it to provide grid services to ratepayers while controlling costs.

Compared to the HERA model, the IGO model would imply significant transition costs. It would also increase the likelihood of rate volatility due to the market structures and would require

[168] Public Utilities Commission. *Order No. 35411 Instituting a Proceeding to Investigate Performance-Based Regulation*. Docket No. 2018-0088. April 18, 2018.

substantial legal work. However, it is more likely to result in greater competition at the distribution level.

The Lighter PUC Regulation model implies reducing the PUC's current regulatory oversight over KIUC to reduce the co-op's regulatory burden and improve its ability to launch new initiatives. This model decreases the regulatory costs for KIUC by granting it greater autonomy. However, The Project Team's analysis finds that removing direct PUC oversight may hamper the ability to achieve the State goals because the PUC or other state bodies would have less control in directing the utility towards particular targets or programs. Furthermore, the implementation of this model also has potential drawbacks because less PUC oversight comes with fewer safeguards against the management of conflict of interest, short-term decision-making (that have negative impacts in the long term) by the KIUC Board, and disputes between KIUC leadership and a minority of its members.

Task 2.2.6 *(Identification and recommendation for the three most beneficial regulatory models for further consideration)* provides a more detailed discussion on the methodology and approach to determining these three most beneficial regulatory models.

5.12 Indicative timeline to transition to another regulatory model

The steps in the implementation of a PBR regulatory model, regardless of whether it is Outcomes-based or Conventional, include decision-making on the design of the PBR model, issuance of guiding principles and framework for the model, determining outputs and price control methodology, engaging with stakeholders, working with utility companies to develop business plans that are compliant with the new model and revising non-compliant utility company business plans, and finally setting the price control mechanism.

Based on the Hawaii Ratepayers Protection Act (SB2939), PBR needs to be implemented in the state by January 1, 2020. It should take 21 months from the date the law went into effect for the PUC, HECO Companies, and other involved parties to implement the PBR model. Notably, the process has begun with an active investigatory docket already in progress. Hawaii's statutory timeframe is shorter than the time used in the implementation of a similar model in the UK, where the process took 30 months to complete. Nevertheless, the Project Team anticipates that the State could implement PBR in a shorter timeframe as it is a smaller jurisdiction with less complex regulatory structures. The selection of fewer and less complicated regulatory mechanisms could also reduce timelines.

Likewise, the steps in the implementation of Light HERA (under the Conventional PBR + Light HERA model) are the same as those involved in any PUC investigative docket because there is already legislation authorizing HERA. The PUC has stated that the next step in implementing HERA is an investigative proceeding, which follows a fairly typical docket proceeding format and schedule that should take approximately two years to complete, based on the average duration of other PUC docket proceedings. Two years is also a reasonable assumption because the HERA implementation is not tied to a strict deadline, unlike the PBR implementation.

When considering the steps and timeline for the implementation of a combined Conventional PBR + Light HERA model, the total timeline would depend on whether the processes are

staggered or not. In the Study, these two models were assumed not to be implemented at the same time. Thus, it is anticipated that establishing this model would take between 39 and 42 months.

Among the three regulatory models selected for further study, the Hybrid model would take the longest to implement. The Hybrid model could be applied in phases/stages over a longer timeline to reduce rate risk that would be inherent with too many regulatory changes at once. The Project Team's staggered implementation features a January 1, 2020 implementation of Outcomes-based PBR to comply with state law, implementation of the IGO in 2023, and implementation of DSPP operations beginning in 2028.

The IGO is likely to take approximately two years to implement, which is similar to the timeline for implementation of ISOs in New York, Texas, and California. Other specific steps regarding the IGO implementation will depend on the design and implementation method the State wishes to use. It is expected that additional steps could be required by an investigatory proceeding into the creation of an IGO to ensure open access, functionally unbundle transmission service, and establish open access transmission tariffs. The results of these steps would also inform action by the state legislature.

The DSPP's implementation is likely to take at least three years and be conducted through a regulatory proceeding. This estimate is based on the experience of New York State, which has been in the process of planning and implementing DSPP since late 2013 and is still not complete at the writing of this Final Report. New York State has initiated a large proceeding over the course of these past four years (including several additional dockets related to different elements of the regulatory framework) and worked with utility companies and other relevant stakeholders to plan and implement various aspects of the overall REV model, including the transition of utilities to Distributed System Platforms. Specific steps they have undertaken include the creation of a Distributed System Implementation Plan Guidance document, approval of joint and individual Distributed System Implementation Plans and the design and implementation of Demonstration Projects by utilities in select service areas. Hawaii is significantly smaller than New York State, and its IOU utilities are organized under the same parent company, so it is possible that implementation could be quicker, especially if Hawaii State regulators can draw on the experience of the New York State initiative.

Task 2.3.1 *(Identification of steps, costs, and projected timelines, for change from the current regulatory model to the recommended regulatory models)* discusses this in detail.

5.13 Legal changes needed to transition to another regulatory model

No changes to the state law would be required to establish a PBR model or implement a Light HERA. It follows that no legal changes would be needed for the Outcomes-based PBR model or the Conventional PBR with Light HERA model. The existing legal framework grants the PUC broad authority for ratemaking and to regulate the electric utilities, which would likely include authority to change the ratemaking procedure from COS to PBR. Furthermore, the Hawaii State Legislature enacted in 2018 a law specifically requiring the design and implementation of PBR in the State.

On the other hand, the Hybrid model would require new legislation to enable the various components of this model, for instance, the IGO. While the state has no explicit law for a DSPP model, its creation should fall under the broad regulatory authority of the PUC. However, to err on the side of caution, and to follow its own precedent of legislating specific PUC responsibilities, the state legislature may want to issue legislation to authorize DSPP explicitly if this model is to be adopted. For the IGO model, there is currently no legal authority to create an IGO. While the PUC may be authorized to implement some aspects of it (such as opening an investigative proceeding to learn about IGOs or using HERA to carry out some functions that the ISO would do), the Project Team expects that legislation explicitly authorizing the creation of an IGO, and its regulation by the PUC, would be necessary to implement this element of the Hybrid model.

Task 2.3.2 *(Analysis of Hawaii law and history to determine the regulatory and legislative changes needed to implement the recommended regulatory models)* provides a more detailed discussion on this.

5.14 Potential costs required to implement the regulatory models

The costs of implementing PBR include the operational costs associated with the PUC and stakeholders undertaking the work necessary to implement the model successfully. Based on an analysis of jurisdictions that transitioned from COS to PBR, such as Alberta (Canada) and UK, together with a review of the PUC's current operating expenses, the Project Team estimated that the cost of implementing Conventional PBR in the State could result in a 10.9% increase in the PUC's average annual expense during the transition period. The costs of operation following the transition period would be similar to the PUC's current average annual expense.

The costs of implementing and operating the HERA entity are also based on an analysis of another jurisdiction that made a similar transition to a system with a HERA-like entity. In particular, the Project Team looked at the Electric Reliability Council of Texas ("ERCOT") Reliability Authority, as the states of Texas and Hawaii are similar in that they both are isolated from the interconnected power systems serving the eastern and western United States,[169] and have integrated significant quantities of renewable generation over the past few years. Using this analysis, The Project Team estimated that the HERA transition costs could range from $234,000 to $585,000 while the annual operating costs would range from $483,000 to $1,208,000.[170]

For the Hybrid model, the Project Team acknowledged uncertainty for cost calculations in both the IGO and DSPP models because there are few examples from which comparisons may be drawn. Nevertheless, depending on the method of calculation, the IGO would cost at least $8 million to $67 million in startup costs, with annual operating costs of a similar magnitude, based on a scaled comparison to mainland RTOs, which are similar to the proposed IGO.[171] The costs of

[169] Although Texas does have asynchronous interchange capability with the rest of the mainland US grid.

[170] The direct scaling cost estimates for a transition to HERA ($234,000 to transition, $483,000 annual operating costs) refer to the scaled, per-kWh start-up costs of ERCOT's Reliability Authority and the operating costs of NERC. The more conservatively scaled estimate that reflects Hawaii's smaller size ($585,000 to transition, $1.2M in annual operating costs) is derived by applying FERC's 250% cost factor for small jurisdictions.

[171] The lower estimate of $8 million for startup and annual operation costs is based on the "small jurisdiction" per-MWh cost identified by FERC and the forecast of 11.9TWh in annual electricity sales in Hawaii. The larger

implementing a DSPP are estimated at approximately $51 million for all the three IOU utilities, spread over a three-year transition period, and $1 million in annual operating cost thereafter.[172] The cost estimates are derived by scaling the costs of National Grid's Distributed System Platform demonstration project in Buffalo, NY (which is part of the NY REV proceeding) to Hawaii by the amount of distributed generation resources served. While the DSPP component of the Hybrid model adds substantial costs, it could also expand the potential to open new revenue streams and encourage the use of more DERs. Task 2.3.1 *(Identification of steps, costs, and projected timelines, for change from the current regulatory model to the recommended regulatory models)* discusses this in detail.

5.15 Funding mechanisms

Under the Outcomes-based PBR model, how utilities fund their costs would be no different than the way by which utilities recover costs under the Status Quo. In other words, utilities would continue to employ private financing mechanisms (i.e., short- and long-term debt, and equity), as well as cost recovery through revenue requirements. Hawaii's existing legal framework also has a series of further mechanisms in place that utilities employ to recover capex, such as the Major Project Interim Recovery adjustment mechanism, as introduced through the 2017 Decoupling Order. As such, utilities would continue to fund capex through capital markets and recover operational and financing costs through rate cases. Despite little change with regards to utilities' funding mechanisms, there would be specific impacts to cost categories that a change in the regulatory model (i.e., to the Outcomes-based PBR model) would bring. This includes a potential increase in administrative costs to utilities due to increased data gathering brought upon by PIMs and a likely increase in savings due to fewer rate cases. Further details regarding the impacts on costs can be found in Task 2.5.3 *(Analysis of how costs differ under each regulatory model).*

Under the Conventional PBR component of the proposed Conventional PBR with Light HERA model, utilities would continue to source funding as under the status quo and Outcomes-based PBR approach. With respect to the HERA component of the model, utilities would fund the change in the proposed regulatory model through a surcharge, separate from the revenue requirement of the utility, as enabled by the existing legal framework in the State of Hawaii. More specifically, under the provisions of Chapter 269 of the Hawaii Revised Statutes, utilities would be able to create a surcharge to be collected to fund the entity elected to be HERA.

Similar to the earlier alternative regulatory models, the utility funding mechanisms under the Outcomes-based PBR component of the Hybrid model would be no different than under the status quo. Nonetheless, under the DSPP model, utilities would be able to fund investments related to the adoption of grid platform infrastructure and technology through including these investments in the utilities' revenue requirements. In other words, these costs would ultimately appear on the end-consumers' monthly electricity bills. That being said, the DSPP model does

estimate of $67 million in startup and operational costs is based on the lower range of the cost range provided by FERC.

[172] The cost estimates for IGO and DSPP refer to the combined costs across the HECO Companies. In the analyses, the Project Team allocated a share of these costs to each utility based on overall demand for IGO, and on planned DER capacity for DSPP. The Project Team acknowledged that this approach may underestimate the fixed costs necessary to implement these models on each island.

introduce other revenue streams for utilities aside from the traditional revenues that come with the sale of electricity. For instance, as DSPPs, utilities would also be able to earn Platform Service Revenues ("PSRs") for providing market-facing platform activities for market participants. Further, under the IGO component of the Hybrid model, additional costs would be recovered similarly to ISOs. Like ISOs such as ISO New England, New York ISO, and PJM Interconnection, the IGO could fund its opex and capex through a combination of private financing and fees to market participants (which would trickle down to retail customer bills).

Task 2.5.5 *(Identification of funding mechanisms for each regulatory model)* provides a detailed discussion on the potential funding mechanisms for these regulatory models.

Figure 43. Summary of regulatory models' respective funding and recovery mechanisms

Regulatory model		Funding mechanism
1) Status quo		• Private financing (short- and long-term debt and equity) • Recovery through rates from customers (revenue requirements)
2) Outcomes-based PBR		• Private financing (short- and long-term debt and equity) • Major Project Interim Recovery adjustment mechanism • Recovery through rates from customers (revenue requirements)
3) Conventional PBR with Light HERA	**Conventional PBR**	• Private financing (short- and long-term debt and equity) • Recovery through rates from customers (revenue requirements)
	HERA	• Surcharge to customers (separate from revenue requirements)
4) Hybrid	**Outcomes-based PBR**	• Private financing (short- and long-term debt and equity) • Recovery through rates from customers (revenue requirements)
	DSPP	• Recovery through rates from customers (revenue requirements) and earnings from market-facing platform activities for market participants
	IGO	• Recovery through fees to market participants

5.16 Potential impact on the staffing needs of the PUC

Since the three most beneficial regulatory models are relatively innovative, only a few jurisdictions have some elements of these recommended models in their current regulatory framework. Therefore, the Project Team selected some jurisdictions for further review of staffing in relevant agencies. The UK and Ontario were chosen to represent the Outcomes-based PBR model. Illinois, Alberta, and New South Wales were selected to represent the Conventional PBR with Light HERA model.[173] Since no jurisdiction currently has the Hybrid model, the Project Team chose New York as an example because its REV initiative shares similar elements to the Outcomes-based PBR as well as DSPP models. New York also has an independent system operator. The Project Team compared the staffing numbers before and after the change of regulatory models to study the impact of the change on staffing relevant State agencies.

[173] Since HERA does not exist in Hawaii and there is no similar entity in other jurisdictions, this section focuses on jurisdictions that implemented Conventional PBR only.

The Project Team's primary observations include the following:

- The jurisdiction (i.e., New York State) that is moving towards a Hybrid model has a higher staff-to-customers ratio in the PUC than jurisdictions with other regulatory models. This is because of the more complex regulatory framework under a Hybrid model that requires more technical staff to design and monitor the regime;
- Outcomes-based PBR-dominated and Conventional PBR-dominated jurisdictions, such as the UK, Ontario, Malaysia, Alberta, and New South Wales, have a lower staff-to-customers ratio in the PUC than the jurisdiction (e.g., New York State) with the Hybrid model;
- When implementing PBR mechanisms, the PUCs usually hire external consultants, which might result in unchanged staffing needs.
- Jurisdictions with more ambitious and active clean energy policies or initiatives tend to have more staff members but not necessarily higher staff-to customers ratio in relevant regulatory agencies;
- Staff's skill sets and expertise are very similar across different regulatory models; and,
- The divisions under regulatory agencies are organized by function, like engineering, policy research, personnel, administration, etc.; these organizational breakdowns are similar across different regulatory models.

Based on the analysis of representative jurisdictions, it is anticipated that a potential impact of an Outcomes-based PBR model on staffing needs is inconclusive since the staffing needs increased in the UK but stayed constant in Ontario after the implementation of this model (this outcome could be explained by the hiring of consultants). On the other hand, implementation of the Conventional PBR with Light HERA model as well as the Hybrid model could potentially increase PUC's staffing needs, given their additional responsibilities.

Furthermore, the oversight management and staffing needs of related State agencies and stakeholders will be affected by various factors other than the regulatory model. This analysis is a relative assessment for the purposes of comparing alternative utility regulatory models. The Project Team's review was not intended to be used as an assessment of the appropriate staffing level given the specific considerations and issues for the Hawaii PUC and DCA, which is outside the scope of this study.

Task 2.3.4 *(Assessment of how each regulatory model could impact state agencies)* provides an analysis of how a change to the regulatory model could affect the staffing needs of the PUC.

5.17 Potential impact of the regulatory change on DERs

A change to the State's regulatory models could be considered as one of the key drivers of DER deployment with respect to facilitating interconnection, incentivizing utility investment, and creating markets for DERs to offer grid services.

Among the regulatory models reviewed, the Hybrid model and the Outcomes-based PBR would most likely provide the most positive impacts on DERs.

As discussed earlier, the Hybrid model combines the Outcomes-based PBR, DSPP, and IGO models, taking advantage of the benefits that each of those regulatory models offers to support DER penetration. An Outcomes-based PBR would allow regulators to incentivize utilities to include DER interconnection targets in their multi-year business plans. A DSPP creates a marketplace and revenue streams for DER products, thus attracting investors. Meanwhile, through an IGO, third-party DER providers would benefit from a transparent interconnection process, thereby addressing inherent conflicts of interest that the utility faces under other regulatory regimes. Figure 44 illustrates the overall impact that a shift in the regulatory model could have on the level of DERs as well as energy security and reliability in the State of Hawaii.

Figure 44. Impact of change of regulatory model to the DERs and energy security and reliability

Change of the Regulatory Model	Distributed generation	Energy storage	Demand response	Energy efficiency	Electric vehicles	Energy security and reliability
Move to Outcomes-based PBR	↑	↑	↑	↑	↑	↑
Move to Conventional PBR with Light HERA	↑	↑	↑	↑	–	↑
Move to Hybrid model	↑	↑	↑	↑	↑	↑
Move to Lighter PUC Regulation	–	–	–	–	–	–

Finally, the successful integration of high levels of DERs would depend on the design of the mechanisms and incentives provided to both the utilities and DER providers, as well as on the political will of the government to complete the transition. Task 2.4.1 *(Estimated potential for each model to increase distributed energy resources)* provides a more detailed discussion on this topic.

5.18 Potential impact of the regulatory change to the residential electricity rates in Honolulu, Hawaii, and Maui Counties

For Honolulu, Hawaii, and Maui Counties, the implementation of the three models each result in the lowest projected average residential rates, as shown in Figure 45 below.

- Conventional PBR + Light HERA model in Honolulu County;
- Hybrid model in Hawaii County; and
- Outcomes-based PBR in Maui County.

The implementation of the three regulatory models is projected to lower average electricity rates relative to the Status Quo in these counties during the forecasted horizon. The most important drivers of cost efficiency and lower rates are:

i) PIMs that incentivize the utility to lower certain categories of costs. The PBR models included several types of PIMs that offer financial incentives in the form of shared savings

to the utility for lowering certain categories of costs. These categories include the cost of the final delivered energy, the total cost per customer, the total cost per km of wires, and cost savings in renewable generation procurement.

ii) ESM, which allows the ratepayers to recover half of the utility's excess earnings. Even after cost savings under PIMs, if a utility's actual revenues for a year result in an effective rate of return that is higher than the approved rate of return plus a pre-determined dead band, an ESM allows ratepayers to recover half of the excess earnings in the next regulatory period.

iii) The totex approach, which incentivizes the utility to lower overall spending on capex and opex combined. Under the totex approach, utilities set an overall expenditures target, combining both capital and operating expenses. Utilities would also retain part of the savings if they lower their spending below the target levels. In addition, relative to the Status Quo, the forecasted returns on RAB are projected to be higher under the PBR models despite lower totex spending.[174]

It is important to note that although the rates are projected to be lower in real terms under the PBR models compared to the Status Quo on average between 2018 and 2045, there are some years for which rates are higher for the PBR models. Task 2.5.2 *(Assessment of system average retail rates for each regulatory model)* provides an evaluation of the projected retail rates for residential, commercial, and industrial customers up to 2045.[175]

The impact of each regulatory model varies between the utilities because of the relative importance of rate base, purchased power expenses, PIMs, and ESMs for each utility's revenue requirement calculations.

Compared to the analysis of ownership models, separate assessment for different regulatory models being implemented on an island-by-island basis for Maui County was not performed. In other words, it assumed that any regulatory model implemented on Maui County would be the same across the three Maui County islands. Implementing a different regulatory model on each island would increase costs of the utilities, PUC, and DCA. Therefore, it is more advantageous in terms of costs and efficiency to minimize the regulatory differences to the extent possible across the islands.

[174] Regulated Asset Base under the cost-of-service model is the net book value of the utility's investment base on which a rate of return is applied to determine the allowed return to investors. Under the totex approach, a pre-determined proportion of the total expenditures gets added to the RAB, based on a capitalization rate. This would remove the capex bias that IOUs have under the cost of service model.

[175] To derive the projected average retail rates under each ownership model up to 2045, the Project Team created a revenue requirements model for each regulatory model and for each county. For the ownership models, a total of 12 revenue requirements models was created. Please refer to the following memos for additional information on the assumptions that the Project Team has used and the results of the revenue requirements: Task 2.5.1 *(Estimated annual revenue requirements for each of the remaining recommended regulatory models)* and Task 2.5.3. *(Analysis of how costs differ under each regulatory model).*

Figure 45. Average impact of a change in the regulatory model on residential rates relative to the Status Quo (2018 – 2045) for customers of the HECO Companies

Change of the Regulatory Model	Honolulu County	Hawaii County	Maui County
Implement an Outcomes-based PBR model	-2.1%	-4.8%	-2.2%
Implement a Conventional PBR + Light HERA model	-2.2%	-4.4%	-1.9%
Implement Hybrid Model	-0.4%	-9.2%	-2.2%

5.19 Potential impact of the regulatory change to the residential electricity rates in Kauai Counties

For Kauai County, Lighter PUC regulation results in the lowest rates because of lower anticipated regulatory costs for the utility. On the other hand, the HERA model would yield the highest rates because HERA represents an incremental expense without direct financial benefits to the ratepayers. The benefits of HERA are more oriented towards the quality of service than cost reductions. As for the IGO model, the Project Team anticipates that there would be some efficiencies from transferring grid operations to a specialized independent entity that manages both utility-scale and distribution level supply resources.

Figure 46. Average impact of a change in the regulatory model on residential rates relative to the Status Quo (2018 – 2045) for KIUC customers

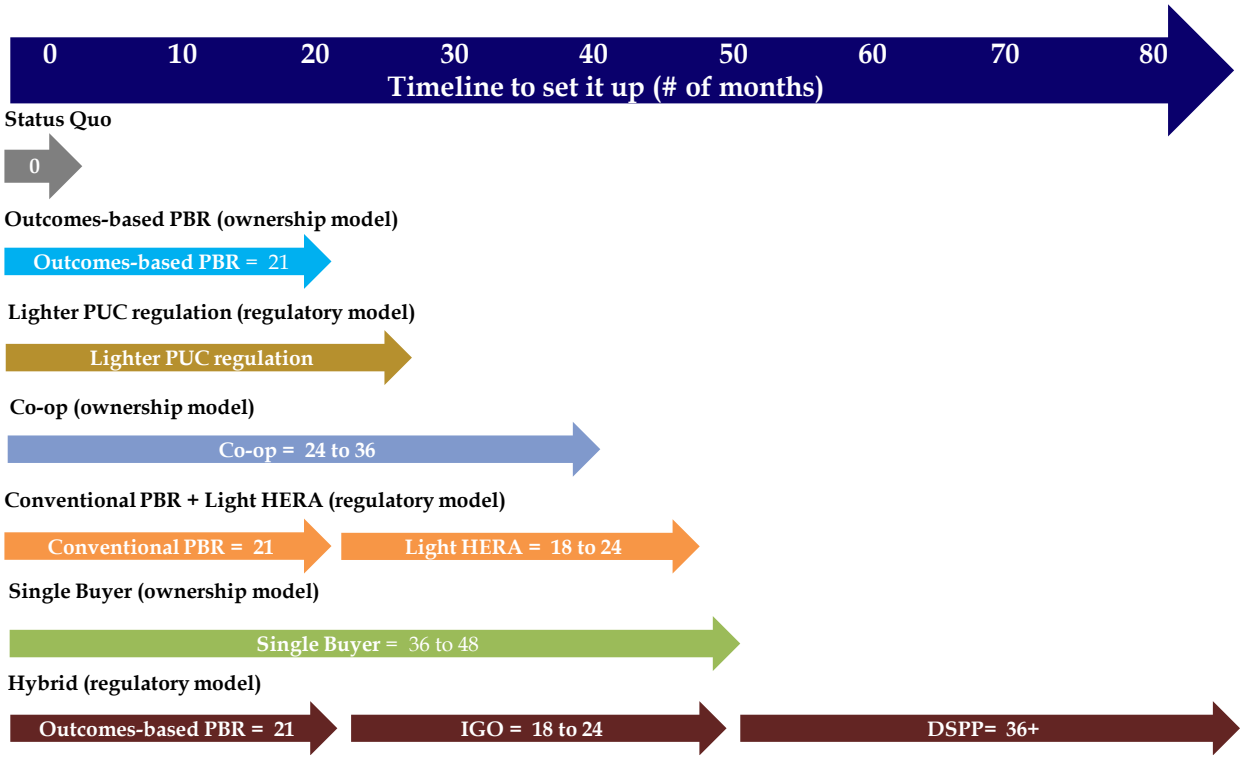
Change of the Regulatory Model	Kauai County
Move to a Lighter PUC Regulation	-0.8%
Establish a HERA model	0.0%
Establish an IGO model	-0.2%

6 Combining the findings under the ownership and regulatory models

6.1 Timeline to move to another model

Among all the selected models reviewed, the Outcomes-based PBR model would take the shortest time to implement because there is already an existing law allowing for the implementation of this model and an open PUC docket. On the other hand, the Hybrid model would take the longest since this model involves the creation of the IGO and DSPP, which currently would require some legislation changes.

Figure 47. Indicative timeline to set up the different regulatory models



6.2 Legal changes needed to move to another model

The only ownership or regulatory models the implementation of which would require a change in the law are the SB, Hybrid, and, potentially, the Lighter PUC regulation models. Current legislation already allows for the creation of HERA and the implementation of PBR. Legislative action is needed to create the new entities associated with the SB, IGO, and DSPP constructs.

For lighter regulation of co-op utilities, there is an existing legal framework (both statutory and case law authority) that would allow the PUC to waive or exempt electric co-ops from any regulatory requirements (i.e., for KIUC to be deregulated).[176] However, there is currently no authority for the PUC to otherwise revise or customize regulatory requirements for electric co-

[176] HRS § 269-31(b); HAR §§ 6-61-159, 160.

ops that are unique from the regulation of IOUs. As such, assuming an intent to customize regulatory requirements that apply to electric co-ops (in addition to simply waiving or exempting electric co-ops from certain or all regulatory requirements), the State Legislature would need to either customize any statutory laws for electric co-ops or authorize the PUC to do so.

Figure 48. Summary of legal changes required for each model

	Models	Legal/regulatory changes required to move to a new model
Ownership Models	**Status Quo (IOU)***	No
	Co-op	No – burden of proof rests on the co-op to demonstrate that it can meet the laws and regulations already in place
	Single Buyer (within the utility)	Yes – Might require a PUC proceeding
	Single Buyer (outside the utility)	Yes – Legislative action is required to establish a new entity to undertake planning and procurement responsibilities from the utility
Regulatory Models	**Status Quo (COS with some PBR mechanisms)**	No
	Outcomes-based PBR	No - no legal changes needed because PBR falls under existing PUC authority
	Conventional PBR + Light HERA	No - there is existing regulation already for both PBR and HERA
	Hybrid	Yes - PUC proceeding is required and legislative changes may be required to authorize a DSPP
	Lighter PUC regulation	Yes - the State Legislature would need to either customize any statutory laws for electric co-ops or authorize the PUC to do so

6.3 Various costs required to move to another model

A change in ownership or regulatory model would be accompanied by certain costs of transition as well as changes in the costs of utility operations. Broadly, a change in model results in three categories of impact on costs.

Transition costs

Any changes in the model would entail costs associated with conducting the necessary stakeholder outreach, or creating new entities like SB and IGO, or passing new laws and regulations. These costs can vary based on the timeline of the transition and extent of legal or regulatory changes required. Changes in the law could be necessary to create an SB outside the utility or an IGO, which would mean higher costs of transition.

Non-recurring implementation costs

The initial costs to implement a new model can be of different types. For a change in ownership from an IOU to a co-op, an acquisition transaction is necessary for the newly formed co-op to purchase the assets and operations from the incumbent utility. In case of a change to an SB model or creating an IGO and DSPP for the Hybrid regulatory model, implementation requires initial capital expenditures on the software and office facilities of the new entity.

Recurring costs of operation

Once the utility operations commence under a new model, some categories of costs change from the Status Quo. Under a co-op model, a utility would be exempt from federal income taxes, would have lower interest rates but higher interest expenses from the initial acquisition, and is expected to have lower costs of procuring power. An SB is also expected to have lower purchased power costs, but the utility's expenses under its planning and procurement divisions would be lower since some of those functions would move to the SB. Similar changes are also expected with an IGO. Under a PBR regime, utilities face incentives to achieve certain outcomes in the form of rewards or penalties.

The Project Team expects that all costs are ultimately passed to ratepayers, either directly or indirectly. Ratepayers are expected to benefit financially from a change in the model if there are sufficient costs savings under the third category – recurring costs of operations – to make up from the transition and implementation costs. A change in ownership from the incumbent IOU to a co-op would have the highest implementation costs due to the acquisition costs. The Hybrid regulatory model would also entail high implementation costs to establish an IGO and DSPP alongside an Outcomes-based PBR model, but the Team envisions that there would be staggered implementation, which would help lower cost impacts to ratepayers.

6.4 Potential impact on the PUC staffing

A change in the ownership or regulatory model does not necessarily require a change in the staffing needs of the PUC. There are other factors that may impact the PUC's staffing needs, such as complexity of policies or initiatives of the jurisdiction, number of utilities, number of customers, and services provided by the PUC.

6.5 Potential impact on DERs

Among the most beneficial models reviewed, the regulatory models would most likely provide the most positive impacts on DERs (Figure 49). The Hybrid and the Outcomes-based PBR models would most likely help in the growth of all types of DERs such as DGs, storage, DR, EE, and EV. This is because these models would likely incentivize utilities to include DER interconnection targets in their multi-year business plan. Under the Hybrid model, the DSPP would create a marketplace for DER products and thus attract investors. Third-party DER providers would also benefit from fair interconnection process through the IGO.

Moreover, the models that have a PBR variation would most likely strengthen energy security and reliability because of the incentives that could be tied to the utility's performance in ensuring these.

Lastly, among the models, the Lighter PUC Regulation would most likely not significantly impact the deployment of DERs.

Figure 49. Indicative impact on the DERs

	Change of the Regulatory Model	Distributed generation	Energy storage	Demand response	Energy efficiency	Electric vehicles	Energy security and reliability
Ownership	Move to IOU	—	—	↑	—	↑	—
	Move to co-op	↑	↑	↓	↑	—	—
	Move to Single Buyer (within the utility)	↑	↑	—	—	—	—
	Move to Single Buyer (outside the utility)	↑	↑	—	—	—	—
Regulatory	Move to Outcomes-based PBR	↑	↑	↑	↑	↑	↑
	Move to Conventional PBR with Light HERA	↑	↑	↑	↑	—	↑
	Move to Hybrid model	↑	↑	↑	↑	↑	↑
	Move to Lighter PUC Regulation	—	—	—	—	—	—

6.6 Potential impact on residential rates

The combined results of the revenue requirement and rate analyses for both ownership and regulatory models, illustrated in Figure 50, indicate that changing the regulatory model is more effective at lowering rates than changing the ownership model. Indeed, for the three counties with an incumbent IOU, all three recommended regulatory models are expected to lower rates, on average, between 2018 and 2045, with respect to the Status Quo and other ownership models. For Kauai County, the Lighter PUC Regulation model is projected to yield the lowest rates. While the HERA model is not expected to impact rates with respect to the status quo, the IGO model is expected to result in lower rates than the IOU or SB models.

In general, the ownership changes are projected to be less efficient than regulatory changes at lowering rates primarily because changes in regulation can impact a wider range of cost factors and therefore offer greater flexibility in lowering rates. For instance, in counties with a Status Quo IOU, the PBR models offer multiple levers with which to lower rates. PIMs could be designed to target specific categories of costs, which would offer stronger and more direct incentives for the utilities to lower them. With the totex approach, utilities could offer fair returns to their investors even while improving their efficiency with regards to overall expenditures. Finally, the ESM component would effectively act as a delayed cap on utility earnings – excess earnings in one regulatory period would be returned to the ratepayers in the next.

Figure 50. Summary of impact on residential rates by county and model (average, 2018 – 2045)

	Honolulu County	Hawaii County	Maui County	Kauai County
Alternative ownership model				
Move to a co-op model	↑ 5.3%	↑ 8.2%	↓ -1.8%	
Move to a Single Buyer within the utility model	↓ -0.7%	↑ 0.3%	↓ -1.3%	↑ 1.0%
Move to a Single Buyer outside the utility model	↓ -0.8%	↑ 0.3%	↓ -1.3%	↑ 1.0%
Move to an IOU model				↑ 6.7%
Alternative regulatory model				
Implement an Outcomes-based PBR model	↓ -2.1%	↓ -4.8%	↓ -2.2%	
Implement a Conventional PBR + Light HERA model	↓ -2.2%	↓ -4.4%	↓ -1.9%	
Implement Hybrid Model	↓ -0.4%	↓ -9.2%	↓ -2.2%	
Move to a Lighter PUC Regulation				↓ -0.8%
Establish a HERA model				0.0%
Establish an IGO model				↓ -0.2%

In Kauai County, it is assumed that KIUC is already operating with a cost minimization approach, so a change in the ownership model is not expected to result in additional cost reductions. Therefore, the costs associated with the transition to a new ownership model would increase rates. A change in the regulatory model, on the other hand, could offer opportunities to lower specific categories of costs. A Lighter PUC Regulation model is expected to result in the lowest average rates for KIUC members because the utility's regulatory expenses would decrease. The IGO model is expected to improve cost efficiency in overall grid planning and operations, especially in integrating DERs but also add costs for the transition and subsequent operation of the IGO. Although the IGO model is also projected to lower average rates relative to the Status Quo co-op, the net benefits in terms of rate reduction would be lower than under a Lighter PUC Regulation model.

7 Additional analyses

7.1 Comparative assessment of rate design changes

The Project Team also conducted a high-level qualitative assessment of whether the benefits of ownership and regulatory model changes can be achieved through changes in rate design. The alternative rate design options evaluated in the analysis are summarized in Figure 51 below.

Figure 51. Rate design options

Rate	Description
Time-of-Use ("TOU") Rates	Provide time-differentiated pricing which reflects the expected cost of providing electricity. TOU rates typically differentiate between "on-peak" and "off-peak" periods to reflect variable prices with on-peak periods having higher energy charges. TOU rates provide improved price signals compared to traditional flat rates and therefore incentivize consumer response. As a result, TOU rates have the potential to maximize consumer savings and encourage the adoption of DERs.
Real-Time Pricing ("RTP") rate	Another form of time-varying rate design in which the consumer rates reflect the actual real-time hourly costs of generating and delivering electricity. RTP rates require the use of smart meters capable of monitoring and reporting hourly prices and usage patterns.
Critical Peak Pricing ("CPP") rates	Rate design in which utilities set substantially higher rates during "critical peak periods" which occur during specific hours of a given year. Similar to TOU rates, this design incentivizes consumers to lower their energy consumption during the identified peak periods and subsequently increase their savings.
Inclining block rates	One of the most common forms of residential rate design, it involves a mechanism by which energy rates increase as the amount of energy consumption increases.
Declining block rates	This rate design offers decreasing energy rates as consumers increase their level of energy consumption. It encourages increased energy consumption by consumers and consequently fails to maximize cost savings or encourage adoption of alternative energy sources such as DERs.

After recalling the benefits of the most beneficial ownership and regulatory models evaluated in prior tasks, a comparative assessment of the alternative rate design options was performed. In doing so, the Project Team assessed the relative ability of these rate design changes to:

1. maximize consumer savings (including the maximum possible impact in percentage terms based on previous experience);
2. enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs;
3. eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation; and
4. align management, ownership, and ratepayer interests.

Based on this high-level qualitative assessment, the Project Team concluded that rate design changes can be effective complementary mechanisms to ownership and regulatory changes and could help achieve some of Hawaii's state energy goals, such as increasing the adoption of DERs and other consumer side resources, lowering peak demand, and encouraging energy conservation. Furthermore, depending on overarching ownership or regulatory model changes,

rate design changes can contribute to increasing consumer savings and, to an extent, aligning utility and consumer incentives.

However, it is important to note that rate design is interlinked with prevailing regulatory and ownership models and can help advance or undermine state policy goals. As such, policymakers and regulators must be mindful of state policy objectives and the broader ownership and regulatory context when considering changes to rate design. Indeed, given the broad array of initiatives underway in Hawaii, a quantitative analysis of any potential rate design changes may be warranted once those initiatives have been implemented. Task 3.1.1. *(Assessing whether benefits of changes from ownership and regulatory model changes could be accomplished through changes in rate design)* and Task 3.1.2. *(Assessing how rate design compares to regulatory and ownership model changes considering overall market conditions)* provide a more detailed discussion of this subject.

7.2 Single-county vs. multi-county model

Aside from the analysis of ownership and regulatory models, the Project Team also conducted an assessment of the management of the State's electricity sector with each county operating independently, as compared to a multi-county model.

The single-county vs. the multi-county models were analyzed from the perspective of the utilities' management and operations, particularly with regards to how the utilities operate the electricity system from sourcing supply to dispatching resources. The Status Quo reflects a single-county model because grids in each county (island) are isolated from those in other counties. Therefore, the operation and management of electric systems are standalone and independent in each county. In contrast, the multi-county model has two or more counties that are interconnected via inter-island transmission lines, which enable joint operations and the dispatch of resources in two or more counties.

Each model has its advantages and disadvantages. The current single-county model provides easier management and operations of the electricity system in each county because the local utility leadership can make operational decisions immediately. Moreover, local utilities are likely to be more aware of what is happening in their respective counties, enabling them to act based on county-specific needs. On the other hand, a multi-county model could better utilize the available renewable resources in each county because of an interisland connection. This would then potentially lower the total cost of management and operations, thereby, reducing retail rates for electric consumers. However, the upfront costs of building and operating the interisland cables are high, making it a controversial topic that triggered significant political and social challenges in the past. Some stakeholders from neighboring counties question whether the interconnection will benefit Oahu only, especially at the costs of neighboring counties.[177]

The analysis showed that the multi-county model is better positioned to address the State's policy priorities as laid out in House Bill 1700 (Act 124) of 2016 and discussed throughout this report. As illustrated in Figure 52, the multi-county model received a better rating in three of five criteria, namely, ability to meet state energy goals, maximize consumer cost savings, and enable a competitive distribution system. In contrast, the single-county model works better in addressing

[177] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 3. Page H-52.

two of the five criteria, namely, conflicts of interest and aligning stakeholder interests. The sixth criteria, transition costs, was not within the scope of the study for assessing single versus multi-county models as it would require a detailed analysis of the costs and policy implications of interconnecting two or more of the island grids which is a separate study unto itself.

Figure 52. Single- vs. multi-county model ability to best meet state policy objectives

Policy objective	Single-county model	Multi-county model
Ability to meet state energy goals	-	*better*
Maximize consumer cost savings	-	*better*
Enable a competitive distribution system	-	*better*
Address conflicts of interest in energy resource planning, delivery, and regulation	*better*	-
Align stakeholder interests	*better*	-

Lastly, while most of the highly ranked ownership and regulatory models would not be impacted by either approach, it would be easier to implement the cooperative model under the single-county approach. Meanwhile, the SB outside the utility model, Integrated Grid Operator and Light HERA (segments of the Hybrid regulatory model) would be more cost-effective under the multi-county approach. Task 3.1.3 *(Assessing the pros and cons of managing Hawaii's electricity sector with each county operating independently as compared to a multi-county model)* provides a more detailed discussion on the pros and cons of the single vs. multi-county models.

8 Appendix A: Summary of stakeholder meetings and calls conducted

8.1 Stakeholder engagement approach

Understanding the input from stakeholders across the state on the ownership and regulatory models for their utilities was an important component of this project. The Project Team interacted with stakeholders to receive their input through three primary mechanisms:

1. Core Group,
2. Public workshops, and
3. Bilateral meetings.

The Core Group was established in the summer of 2017 and consists of members representing the public sector, the counties, and the utilities (Figure 53). Meetings were held with the Core Group, either in person or over the phone, and the Project Team reached out to them via email multiple times throughout the project. The Project Team solicited input from the Core Group on stakeholder identification and outreach and to allow for comment on interim analyses.

Figure 53. Core Group

Public Sector	County Energy Coordinators	County Economic Development Boards	Utilities
• DBEDT • Consumer Advocate • PUC	• Honolulu • Hawaii • Maui • Kauai	• Honolulu • Hawaii • Maui • Kauai	• HECO • HELCO • MECO • KIUC

Two rounds of public workshops were held, in October 2017 and in June 2018. The purpose of these workshops was to solicit input from the public on the ownership models and regulatory models and to provide a high-level overview of mid-deliverable findings for Task 2 and Task 3. In addition to the public workshops, two workshops were conducted at VERGE, one in June 2017 and one in June 2018.

The Project Team also conducted bilateral meetings with multiple stakeholders during the course of the project, both in person and over the phone. Multiple stakeholders engaged in the electricity sector were contacted to request meetings, and the Project Team also received requests from individuals and organizations interested in speaking with them.

The following sections provide statistics on the number of stakeholders that participated in the workshops and with whom the Project Team conducted bilateral meetings.

8.2 Stakeholder workshop participation statistics

The Project Team conducted two rounds of stakeholder workshops during this project. In total, there were 216 participants at these workshops (see Figure 54).[178] The first round focused on the Ownership Model analysis and was conducted during October 2017. There were 141 participants across the eight workshops (see Figure 54 and Figure 55). Maui County had the highest number of participants at 45. The second round focused on the Regulatory Model analysis and was conducted during June 2018. There were 75 participants across the eight workshops (see Figure 54 and Figure 56). Maui County had the highest number of participants at 30.

Figure 54. Ownership and regulatory model workshop participants

County (Town, Island)	Ownership Model	Regulatory Model	Total
City and County of Honolulu	35	24	59
Honolulu, Oahu	29	17	46
Kailua, Oahu	-	7	7
Waialua, Oahu	6	-	6
Hawaii County	34	10	44
Hilo, Hawaii	14	5	19
Kona, Hawaii	20	5	25
Kauai County (Lihue)	27	11	38
Maui County	45	30	75
Lanai City, Lanai	18	6	24
Wailuku, Maui	19	12	31
Kaunakakai, Molokai	8	12	20
Total	141	75	216

[178] There were some stakeholders that participated at multiple workshops.

Figure 55. Ownership model workshop participants

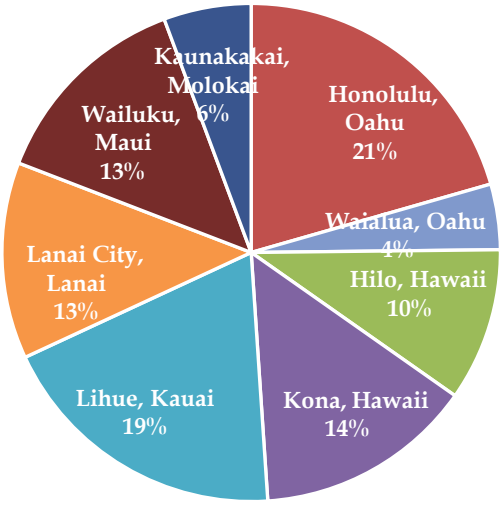
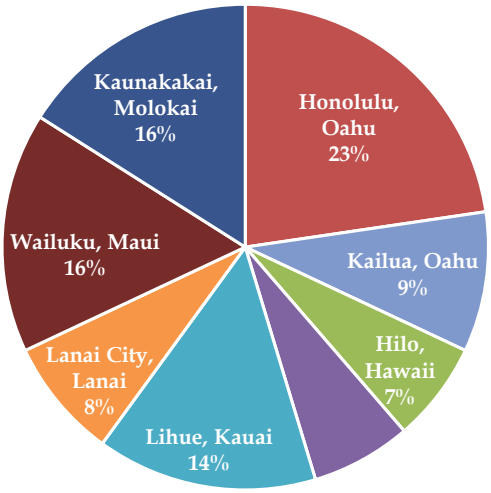


Figure 56. Regulatory model workshop participants



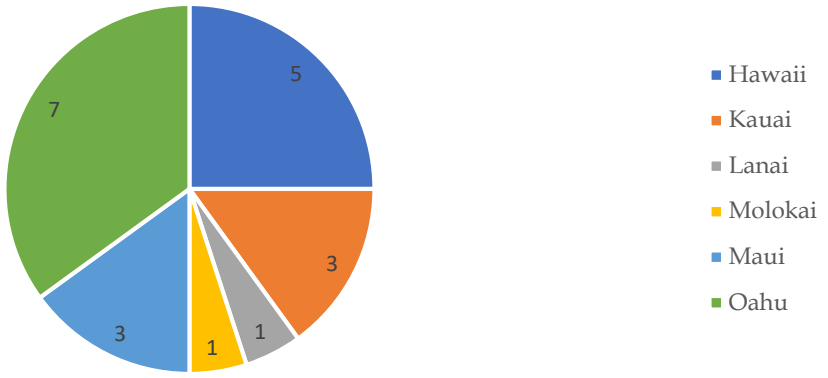
8.2.1 VERGE workshops

The Project Team conducted two workshops at VERGE Hawaii in Honolulu, one in June 2017 and one in June 2018. Unfortunately, many participants did not sign in at these workshops. There were more than 100 participants at each workshop.

8.2.2 Bilateral meetings

Throughout the project, multiple bilateral meetings were conducted with stakeholders across the state. The primary bilateral meetings were conducted in person in association with the ownership and regulatory workshops.

Figure 57. Bilateral meetings in conjunction with ownership model community outreaches, by island



In conjunction with the regulatory workshops, the Project Team met with stakeholders representing 15 organizations (see

Figure 59 and Figure 60). Additionally, the Project Team met or spoke with 24 stakeholders during the summer of 2017 to discuss the project and receive feedback (see Figure 61 and Figure 62).

In conjunction with the regulatory workshops, the Project Team met with stakeholders representing 15 organizations (see

Figure 59 and Figure 60). Additionally, the Project Team met or spoke with 24 stakeholders during the summer of 2017 to discuss the project and receive feedback (see Figure 61 and Figure 62).

Figure 58. Bilateral meetings in conjunction with Ownership Model community outreaches, by Organization Type

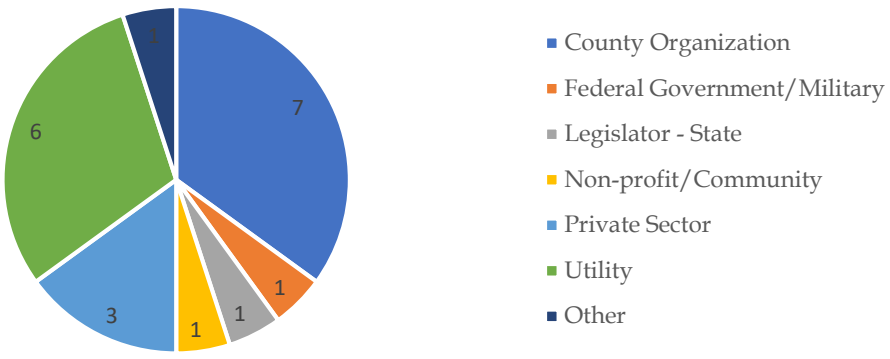


Figure 59. Bilateral Meetings in Conjunction with Regulatory Model Workshops, by Island

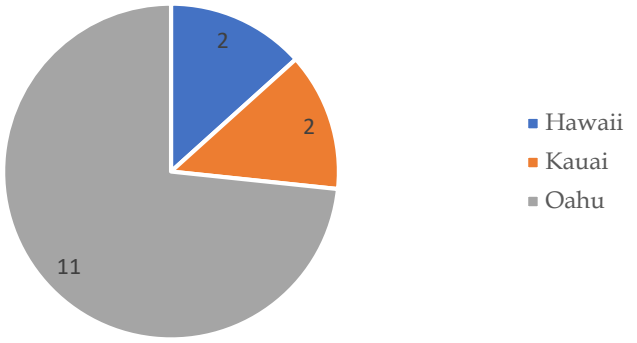


Figure 60. Bilateral Meetings in Conjunction with Regulatory Model Workshops, by Organization Type

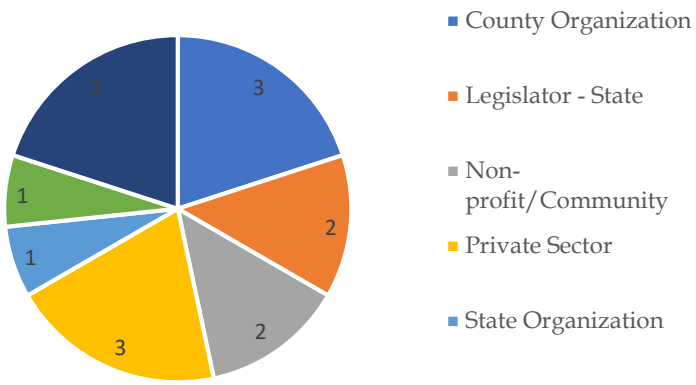


Figure 61. Bilateral Meetings Conducted in June and July 2017, by Island

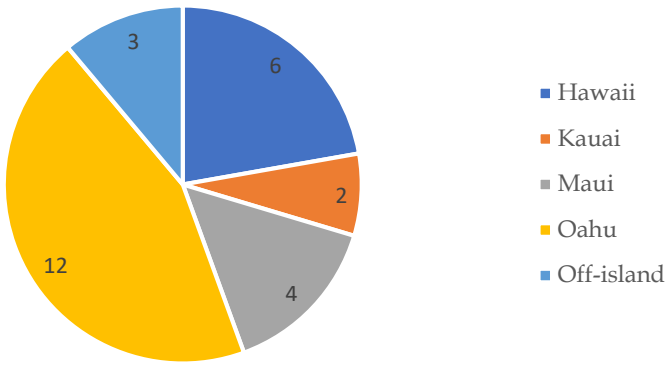
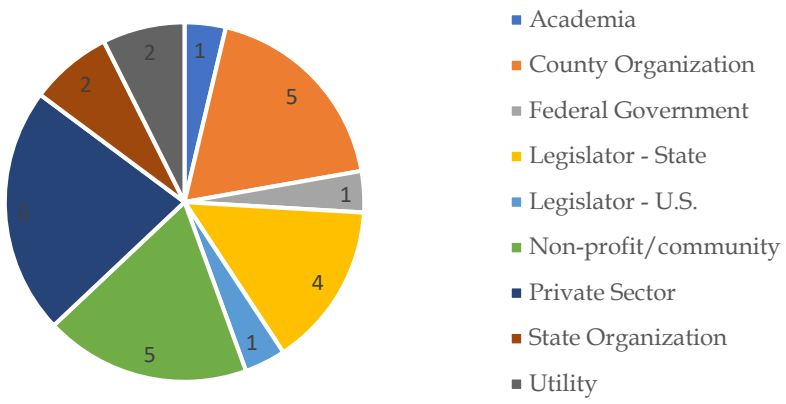


Figure 62. Bilateral Meetings Conducted in June and July 2017, by Organization Type



9 Appendix B: Scope of work to which this deliverable responds

4.1.5 Final formal professional report documenting analyses, incorporating feedback from public meetings in TASK 4.1.4.

CONTRACTOR shall prepare a final draft of the formal professional report with detailed reporting of all research, analysis, and findings of all tasks and subtasks in accordance with the STATE approved detailed outline and incorporating feedback from the public meetings conducted in TASK 4.1.4.

DELIVERABLE FOR TASK 4.1.5. CONTRACTOR shall provide a final draft of the formal professional report with detailed reporting of all research, analysis, and findings of all tasks and subtasks in accordance with the STATE approved detailed outline; incorporating feedback from the presentations conducted in TASK 4.1.4. Deliverable shall include the final formal professional report documenting the analyses and results of all tasks. CONTRACTOR shall provide five professionally bound hard copies and an electronic copy in both MS Word and PDF formats of the Final Report. CONTRACTOR shall submit deliverable for TASK 4.1.5 to the STATE for approval.

10 Appendix C: About the Project Team

10.1 London Economics International

LEI is a global economic, financial, and strategic advisory professional services firm specializing in energy and infrastructure. The firm combines a detailed understanding of specific network and commodity industries, such as electricity generation and distribution, with sophisticated analysis and a suite of proprietary quantitative models to produce reliable and comprehensible results. The firm's roots stem from the initial round of privatization of electricity, gas, and water companies in the UK in the late 1980s. Since then, LEI has advised private sector clients, market institutions, and government on policy initiatives, market and tariff design, asset valuation, market power, and strategy in virtually all deregulated markets worldwide.

The following attributes make LEI unique:

- ***clear, readable deliverables*** grounded in substantial topical and quantitative evidence
- ***extensive experience in regulatory filings*** provides expertise to advise on network tariffs and design rates under PBR
- ***wealth of knowledge of energy and infrastructure regulation*** worldwide to provide expert testimony services on regulatory best practices and innovation
- ***balance of private sector and governmental clients*** enables us to advise both regarding the impact of regulatory initiatives on private investment and the extent of possible regulatory responses to individual firm actions
- ***Boston-based firm*** with in-depth knowledge of energy policies and regional issues
- ***worldwide experience*** backed by multilingual and multicultural staff.

10.2 Meister Consultants Group, a Cadmus Company

Meister Consultants Group, a Cadmus Company ("MCG-Cadmus"), is an international sustainability consulting firm specializing in renewable energy policy and strategy development. The Cadmus Group is a full-service technical consultancy with a track record of delivering customized solutions to clients that address complex challenges in energy, sustainable transportation, climate, the natural and built environment, public health, homeland security and all-hazard preparedness, and international development. With over 600 employees, Cadmus serves government, commercial, and nongovernmental organizations around the world. Within Cadmus, MCG is a leader in clean energy policy, climate change planning, and stakeholder dialogue with a unique approach that is grounded in global best practices but tailored to local context. MCG-Cadmus is particularly recognized for its expertise in island sustainability and resilience, having worked with over 20 island jurisdictions, including Hawaii.

MCG-Cadmus has been on the forefront of local-level energy, climate, and transportation planning in the U.S. Our energy practice addresses all renewable technologies, including their integration with other sectors, such as transportation and the built environment. Our broader sustainability portfolio with government clients encompasses initiatives ranging from emissions

inventory analysis, climate and resilience planning, stakeholder engagement, marketing and education campaigns, energy procurement, sustainability financing strategies, among many others.

10.3 Yamamoto Caliboso, a Limited Liability Law Company

Yamamoto Caliboso is a boutique law firm in Honolulu, Hawaii, which concentrates on helping clients with corporate, energy, financing, real estate, regulatory and public utility law.

Yamamoto Caliboso has one of Hawaii's largest law practices in the area of renewable energy, with industry-leading experience representing independent power producers. Clients include developers of wind, solar, hydro, biomass, and biofuel projects. Yamamoto Caliboso also works with buyers and sellers in the distributed generation industry.

Yamamoto Caliboso handles regulatory matters for clients in the energy, telecommunications, water, sewer, cable and transportation industries, with a particular focus on issues involving the Hawaii Public Utilities Commission. Yamamoto Caliboso serves as regulatory counsel for most of Hawaii's utility-scale independent power producers, as well as for key players in the telecommunications industry.

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Review of potential ownership models that could be applied in Hawaii and their ability to meet state objectives

working paper prepared by London Economics International LLC for the State of Hawaii with support from Meister Consultants Group

July 27th, 2017

London Economics International LLC ("LEI"), together with Meister Consultants Group, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals; this document is one of several working papers associated with that engagement. Eight utility ownership structures were chosen based on the scope of work provided: i) status quo or investment owned utility ("IOU"); (ii) new parent company to IOU; (iii) cooperative ("co-op"); (iv) municipal ("muni"); (v) hybrid with majority government ownership in IOU; (vi) integrated distributed energy resources ("IDER") operator model; (vii) Single Buyer ("SB"); and (viii) grid defection/disperse ownership. Key differences among these models include the role of the utility and the regulator, generation ownership and remuneration, and taxation. Ownership structures across the value chain can also be mixed. Each of the other ownership models, except for the status quo, would require various steps to transform to another ownership model. Our preliminary evaluation of these ownership models shows that the SB, IDER, and new parent company to IOU structures get the highest favorable ratings in terms of achieving State energy goals, maximizing consumer cost savings, enabling a competitive distribution system, and reducing conflicts in energy resource planning, delivery, and regulation.

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List of acronyms

AGDC	Alaska Gasline Development Corporation
APPA	American Public Power Association
ASB	American Savings Bank
B Corp	Benefit corporations
BESS	Battery energy storage system
CBRE	Community-Based Renewable Energy
CFC	Cooperative Finance Corporation
Co-ops	Cooperative utilities
DBEDT	Hawaii Department of Business, Economic Development and Tourism
DER	Distributed Energy Resource
DSP	Distribution System Platform
DUOS	Distribution Use of System
EIA	US Energy Information Administration
EMA	Energy Market Authority
G&T	Generation and Transmission
GMP	Green Mountain Power
HCA	Historical Cost Accounting
HECO	Hawaiian Electric Company, Inc.
HEI	Hawaiian Electric Industries, Inc.
HELCO	Hawaii Electric Light Company, Inc.
HERA	Hawaii Electricity Reliability Administrator
HES	Hermiston Energy Services
HSEO	Hawaii State Energy Office
IDER	Integrated DER
IESO	Independent Electricity System Operator
IOU	Investor-Owned Utility
IPP	Independent Power Producer
IRP	Integrated Resource Plan
ITC	Investment Tax Credits
KIUC	Kauai Island Utility Cooperative
KOGAS	Korea Gas Corporation

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LNG	Liquefied natural gas
MECO	Maui Electric Company, Ltd.
MOU	Memorandum of Understanding
Munis	Municipal utilities
NCSC	National Cooperative Services Corporation
NEB	National Energy Board
NTAs	Non-transmission alternatives
NYSE	The New York Stock Exchange
OPA	Ontario Power Authority
P/B ratio	Price-to-book ratio
PacifiCorp	Pacific Power & Light
PILOT	Payment in Lieu of Taxes
PSC	Public Service Commission
PSH	Pumped storage hydro
PSIP	Power System Improvement Plan
PSO	Power System Operator
PTC	Production Tax Credit
PUC	Hawaii Public Utilities Commission
REV	Reforming Energy Vision
RM	Ringgit Malaysia
RUS	Rural Utilities Service
SB	Single Buyer
SBC	Sustainable Business Corporation
SGS	Schofield Generating Station
TNB	Tenaga Nasional Berhad
UK	United Kingdom

1 Executive summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which responds to Tasks 1.1.1 and 1.2.1 in the project scope of work, provides an overview of and introduction to the various types of utility ownership models and evaluates their features. We have also considered the high-level steps that would be necessary if other ownership structures were to be implemented. Furthermore, Task 1.1.1. also requires us to perform a high-level needs assessment of the existing power sector analysis in the State and needed investments through 2045 to achieve the 100% clean energy goal.

Eight utility ownership structures were selected based on the scope of work provided and our evaluation of various additional potential arrangements. These include: (i) status quo or investment owned utility ("IOU"); (ii) new parent company to IOU; (iii) cooperative ("co-op"); (iv) municipal ("muni"); (v) hybrid with majority government ownership in IOU; (vi) integrated distributed energy resources ("IDER") operator model; (vii) single buyer ("SB"); and (viii) grid defection/disperse ownership. Where necessary, LEI has also discussed elements of the regulatory framework in the discussion as it is difficult to discuss utility ownership models in isolation, though this topic will be discussed in greater detail in a subsequent working paper. Key differences among these models include the role of the utility (e.g., objective function, how profits are distributed, planning horizon) and the regulator, generation ownership and remuneration (e.g., under rate base), and taxation.

State's key criteria in evaluating models based on the legislation

- Achieve State energy goals
- Maximize consumer cost savings
- Enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs
- Eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation

Source: House Bill No. 1700 Relating to the State Budget

Ownership structures across the value chain can be mixed; there are utilities, co-ops, and munis who own only wires, only generation, or combinations thereof. Utilities continue to play a significant role in developing generation under rate base in many of these ownership models and differ only in the perceived motivation of the utility rather than in their function. There is likely to be a bias in favor of generation relative to wires solutions in most of these models except for the IDER and SB models. This is because generally, generation can be built more quickly and with fewer permitting issues. The IDER model is the most supportive of wires investment.

Except for the status quo, each of the other ownership forms would require a series of actions to implement. First among the common steps required for formation in some of these structures is

negotiating with Hawaii Electric Industries' ("HEI")[1] regarding its utility subsidiaries, or with Kauai Island Utility Cooperative ("KIUC") regarding its assets. In this paper, HEI's utilities are referred to as the Hawaiian Electric Company ("HECO"), Maui Electric Company ("MECO"), and Hawaii Electric Light Company ("HELCO") or collectively "the HECO Companies" (or "the Companies"). Subsequent steps common to several of the potential changes in ownership forms include arranging financing and creating procedures and rules (e.g., Single Buyer's Rule), to name a few.

Based on our qualitative and preliminary evaluation of the ownership models relative to the state goals, we find that the SB, IDER, and new parent company to IOU garnered the highest favorable ratings. The municipal model, on the other hand, received the least favorable rating due to its potential inability to meet the state energy goals and enable a competitive distribution system. This is due to the potential for municipal utilities to become highly politicized and be potentially constrained in terms of staffing flexibility. As we perform the quantitative analysis and as we receive inputs from stakeholder groups, these high-level results are subject to refinement.

Finally, with regards to the needs assessment, the HECO Companies and KIUC are ahead of their renewable energy goals and will both be able to achieve the clean energy target before 2045, based on their near-term and long-term plans. More specifically, the HECO Companies plan to achieve the State's clean energy goal by 2040, five years earlier than mandated. Likewise, KIUC expects to reach 100% renewable energy by 2035. Part of the HECO Companies' near-term plan (over the next five years) is to add more than 850 MW of new renewable generation, coupled with aggressive distributed energy and demand response targets. To accommodate the aggressive and large penetration of renewables and to support the resilience of the grid, HECO Companies plan to add a set of energy storage resources, other grid technologies (e.g., synchronous condensers), and other grid system upgrades and expansions. Overall, the resource needs assessment suggests that while the Hawaii Public Utilities Commission ("PUC") approved the Power System Improvement Plan ("PSIP"), the HECO Companies will need to continue to work closely with the regulator, stakeholders, and each other, and perform more comprehensive financial and operation analyses to demonstrate merits and prudency of proposed projects in a transparent manner that is consistent with state and regulatory policies.

As for KIUC, to achieve its strategic goal of getting 70% of its power from renewable generation by 2030, it plans to add over 100 MW of renewable energy by 2025. In the next five years, it also has planned several projects to support the integration of renewables and to ensure resiliency of the grid. These projects include installing battery energy storage systems, repowering, hydro plant penstock replacement, and gas turbine modifications to name a few.

[1] HEI also owns American Savings Bank.

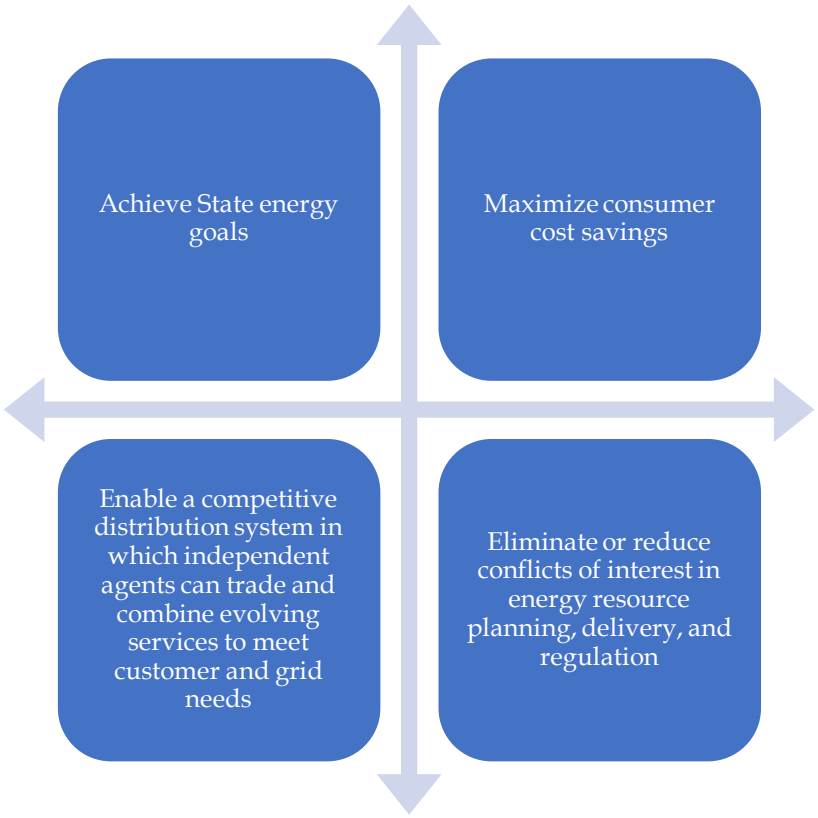
2 Introduction and scope

2.1 Project description

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission on a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[2] was contracted to perform this study.[3]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[4] listed in Figure 1.

Figure 1. State's key criteria in evaluating the models



Source: Scope of Services under Contract No. 65595

[2] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[3] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[4] House Bill No. 1700 Relating to the State Budget.

The study will help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[5]

2.2 Role of this deliverable relative to others in the project

This deliverable is responsive to Tasks 1.1.1 and 1.2.1 in the project scope of work. It introduces the various types of utility ownership models and evaluates their characteristics. However, it is important to note that utility ownership models cannot be considered in isolation from the regulatory framework in which they are embedded. Regulatory models will be the topic of a subsequent set of deliverables.[6]

This deliverable also provides the high-level steps required for the formation of the various utility ownership models. Tasks 1.2.3 and 1.3.1 will provide a more detailed discussion and assessment of the technical feasibility of each model and various steps, the timeline and costs required to change from the current ownership model to new models, respectively.

In addition, various aspects of the ownership models themselves will be further explored in subsequent deliverables. This includes:

- identify and estimate stranded costs for each ownership model by county (Task 1.1.6);
- provide a comparison of system acquisitions of comparable size in the United States within the past 20 years (Task 1.2.2);[7]
- assess technical, financial, and legal feasibility of each ownership model (Task 1.2.3);
- solicit public input from each island currently served by an electric utility on the results of findings under Tasks 1.1.1 to 1.2.3 (Task 1.2.4);
- identify and recommend three feasible ownership models ("recommended models") for further consideration and recommend options for the governance structure under each of these ownership models (Task 1.2.5);

[5] Hawaii Contract No. 65595. Scope of Services.

[6] Deliverables related to the regulatory models are under Task 2 of the Scope of Services.

[7] The comparison will consider the following: (i) the outgoing and incoming ownership and regulatory models; (ii) number of customers served; (iii) capacity; (iv) annual sales; (v) estimated book value; (vi) initial acquisition cost estimate; and (vii) actual acquisition cost for each system.

- identify various steps, timeline, costs (Task 1.3.1) and legal changes (Task 1.3.2) required to change from current ownership model to the new recommended models, including regulatory approvals;

- identify risks for each ownership model (Task 1.3.3) and how each recommended model impacts State agencies staffing and stakeholders (Task 1.3.4); and

- evaluate the costs of ownership and operation and management structure and staffing plan needs of each recommended model (Task 1.4).

Lastly, Task 1.1.1. requires us to perform a high-level needs assessment of the existing power sector assets in Hawaii and needed investments to enable Hawaii to achieve its 100% clean energy goal. We rely on publicly available information and the Hawaiian Electric Companies' (the "HECO Companies," or "the Companies") Power Supply Improvement Plan Update Report ("the PSIP"). This is discussed in detail in Section 5. This high-level assessment will be refined as the project proceeds and as we address the following tasks:

- assessment of existing generation, transmission, and distribution infrastructure in each county (Task 1.1.3);

- assessment of future needs for generation, transmission, and distribution infrastructure in each county (Task 1.1.4); and

- identification of system improvements planned for installation in the next five years and proposed improvements needed through 2045 (Task 1.1.5).

2.3 Future refinements

As noted earlier, this deliverable is an overview to the different utility ownership models and as such, the results of our analysis discussed in this deliverable are subject to further refinement and change as the project moves forward and inputs from the stakeholder groups and results of the quantitative analysis and case studies become available. LEI will provide case studies in some of the deliverables (if applicable) to highlight the important features of the different utility ownership models and key issues and lessons from other jurisdictions or utilities. Furthermore, the project will provide various opportunities for stakeholder inputs and participation. LEI will engage a wide range of stakeholders and perspectives across all islands through a series of facilitated dialogues, one-on-one meetings, and workshops.[8]

[8] A stakeholder workshop was held at the VERGE Hawaii Asia Pacific Clean Energy Summit on June 20, 2017 in Honolulu, Hawaii. The workshop provided an opportunity for the attendees, as well as online participants, to hear from key stakeholders in the energy policy discussion and to provide inputs to the study through the small group discussions.

3 Potential ownership models

3.1 Overview

A wide range of ownership structures for utilities (or companies providing utility-like services) can be observed around the world. Furthermore, technological change is enabling the exploration of new types of ownership arrangements. For the purposes of this paper, we define a *utility* as an entity which is entitled to earn a fair return through charging regulated rates for an essential service in return for assuming an obligation to serve; as per terms of our contract, we focus solely on the electricity sector. We selected the eight different ownership structures below based on both the scope of work provided and our assessment of various additional potential arrangements. While this list of ownership structures is by no means exhaustive, we do believe it is representative of both existing and emerging alternatives.

It can be difficult to discuss ownership models without considering the regulatory framework in which they are embedded. While subsequent deliverables will focus on the regulatory framework in greater depth, where necessary, we make references to it in describing the ownership models below.

It is important to bear in mind the time horizon when discussing each ownership model. While we are generally evaluating ownership models relative to the status quo today, the relative costs and benefits of each ownership model may change over the nearly 30-year time horizon between the present and 2045. As technology changes, non-traditional ownership models may become more feasible.

3.2 Description

Even within ownership types, there can be wide variations. As we describe the ownership models in greater detail, we have attempted to describe them in a way that encompasses the most common forms. However, each can be further customized to meet the needs of the state of Hawaii or individual Hawaiian Islands. As Figure 2 shows, key differences include the extent of local ownership, role of the profit motive, whether the entity is regulated by the Hawaii Public Utilities Commission ("PUC"), and how the ownership structure impacts planning horizons.

Figure 2. Comparing ownership forms across selected attributes

Form	Local Ownership?	For profit?	Regulator	Management time horizon
IOU	limited	yes	PUC	short
New parent under IOU	depends on parent	parent may or may not be	PUC	depends on parent
Co-op	yes	returns profits to members	self*	long
Muni	yes	profits partly fund city budget	city council	medium
Hybrid (Government majority)	yes	profits partly fund state budget	PUC	long
Integrated DER	mixed	yes	PUC	medium
Single buyer	mixed	no for single buyer itself	PUC	long
Grid defection	mixed	yes	building codes	long

Note: Although most of the co-ops are self-regulated, Kauai Island Utility Cooperative is currently regulated by PUC

3.2.1 Status quo

The status quo in Hawaii consists of an investor-owned utility ("IOU") holding company, a co-op, several independent power producers ("IPPs"), and some self-supply. Since we discuss co-ops in a subsequent section, for the remainder of this section we will focus on the IOU form of ownership. Nationally, 189 IOUs serve 68% of US electricity customers.[9]

Hawaii Electric Companies: An IOU in Hawaii

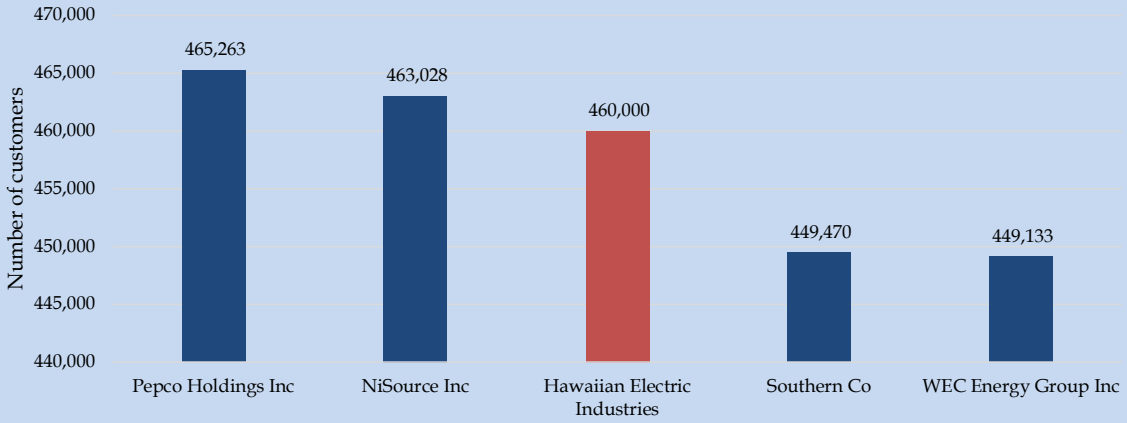
Hawaiian Electric Industries ("HEI") supplies power to approximately 95% of Hawaii's population through its electric utilities, including Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Ltd. ("MECO") or collectively known as the HECO Companies ("HECO"). In addition, HEI owns a financial institution called American Savings Bank, F.S.B.

Number of customers (2016): 460,000 (Electric Utilities)

Total assets (2016): 5,975.43 million (Electric Utilities)

Total revenue (2016): 2,094.37 million (Electric Utilities)

Comparators based on size:*



*Note: * Number of customers in 2015 (except HECO's data in 2016).*
Source: SNL, Velocity Suite, HEI Form 10-K. Energy Information Administration ("EIA") Schedule 4 Part A, B and C

An IOU can be publicly traded or privately held. In the case of HEI, it is traded on the New York Stock Exchange ("NYSE"); 50.0% of its shares are held by institutions.[10] However, in recent years, several IOUs have been taken private by companies like Berkshire Hathaway or Macquarie; we

[9] American Public Power Association. *2015-2016 Annual Directory & Statistical Report.* <http://www.publicpower.org/files/pdfs/uselectricutilityindustrystatistics.pdf>.

[10] Hawaiian Electric Industries, Inc. *Institutional Ownership.* Website. <http://www.nasdaq.com/symbol/he/institutional-holdings>.

will discuss the potential for a new parent in the next section. Being publicly traded can impact management planning horizons; because public companies report earnings quarterly, some observers contend that this leads to a shorter-term mentality.

IOU management reports to a board of directors, which has a fiduciary duty to its shareholders. Management in turn responds to signals from its regulators regarding priorities. Generally, IOUs are required to provide reliable service consistent with good utility practice by making prudent investments. Provided they have done so consistent with prevailing regulations, they are entitled to a fair return. As will be discussed further in the subsequent regulatory framework deliverables, most regulatory regimes place constraints on IOU activities. Often, the best way for IOUs to increase profits is to pursue additional capital investments. While regulators have attempted to change incentives by redesigning rates, IOUs are conditioned to plan according to a return on ratebase – if ratebase is not growing, it is more difficult for profits to grow.[11] As regulatory regimes evolve to incorporate a higher degree of incentives and performance-based elements, the mindsets of the utility, its customers, and its regulators needs to change. For the purposes of this paper, we assume that the status quo regulatory regime continues.

3.2.2 New parent

The extent to which having a new parent changes an IOU's behavior depends on the nature of the parent. IOUs can be owned by other IOUs; they can be owned by private equity firms or conglomerates; the new parent could also be not for profit, a limited dividend, or a benefit ("B") corporation. Ownership by another, larger publicly-traded IOU may provide greater access to capital or human resources, but may not change the IOU's management's planning horizon. Private equity ownership can free IOU management from having to adopt a quarterly mentality; however, some private equity firms have hold periods of five to ten years, after which they are required to monetize the asset. Some firms, such as Berkshire Hathaway (publicly traded but essentially a conglomerate), have assembled vast collections of IOUs across geographically diverse territories. New parents can facilitate growth and innovation, as has arguably occurred at Green Mountain Power ("GMP") in Vermont (GMP was the first utility to be certified as a B corporation). By contrast, new parents can also mean significant leverage and potential distress, as in the ill-fated takeover of Texas Utilities.

There are a number of examples of for-profit companies controlled by non-for-profit entities. For instance, Mountain View Power is an energy marketer in Alberta, Canada. It sells electricity and natural gas to residential, farming, and small business located in the County of Mountain View in Calgary. It is owned and managed by the Olds Institute for Community and Regional Development ("the Olds Institute"). The Olds Institute is a non-profit community and economic development organization and is owned by the community and driven by volunteers. Other examples that are non-utility include the following:

[11] Cost of service ("COS") is the starting point for all regulatory frameworks for regulated utilities. For the purpose of this paper, we assume that the COS is constant across all the ownership models reviewed. Performance-based ratemaking ("PBR") regimes build upon COS principles, including calculation of ratebase, target fair returns, and cost allocation studies.

- The Hershey Trust Company is a controlling stockholder of the Hershey Company and the trustee of the Milton Hershey School, which is a school for disadvantaged children. Founded in 1905, the Hershey Trust Company is a state-chartered trust company.

- The Bosch Group, a global supplier of automotive technology, industrial technology, and consumer goods and energy and building technology. As of 2016, 92% of shares of Robert Bosch GmbH were held by Robert Bosch Stiftung GmbH,[12] a charitable foundation which funds activities related to health care, science, education, and international relations.

- Bremer Bank, which is a $11 billion regional financial services company with branches located in Minnesota, Wisconsin, and North Dakota, is owned jointly by the Otto Bremer Trust (92%) and Bremer employees (8%).[13] The Bremer Trust is one of the country's largest charitable trusts and invests in "communities and regions that are home to Bremer Banks."[14]

Benefit corporations ("B Corp")

B Corp is a type of for-profit corporate entities that are certified by the nonprofit B Lab to meet rigorous standards of social and environmental performance, accountability, and transparency. As a B Corp, the corporation can legally mandate social and environmental considerations other than just profit. As a result, directors possess necessary legal protection to consider the interest of all stakeholders, rather than just shareholders who elected them.

In Hawaii, Senate Bill 298 was passed into law in 2011 as Act 209 to allow businesses in Hawaii to operate under a B Corp or sustainable business corporation ("SBC") structure. As of July 2017, there are seven B Corps in Hawaii, including bCause, Natural Investments LLC, Smart Sustainability Consulting, Hawaiian Legacy Hardwoods, Hawaiian Ola, Hawaiian Paddle Sports, LLC, and Sustainable Pacific Consulting ("Susty Pacific").



[12] Bosch Group. "2016 Annual Report." Page 21. Accessed on July 18, 2017. <https://assets.bosch.com/media/global/bosch_group/our_figures/pdf/bosch-annual-report-2016.pdf>

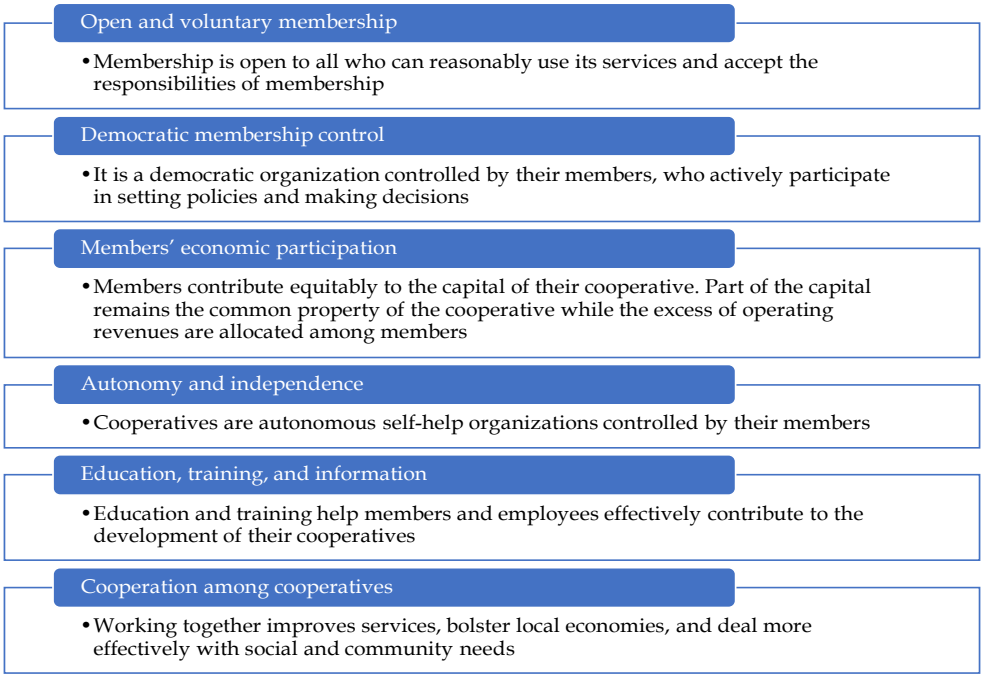
[13] Otto Bremer Trust. "About Us." Accessed on July 18, 2017. <http://www.ottobremer.org/about>

[14] Otto Bremer Trust. "Where We Work." Accessed on July 18, 2017. <http://www.ottobremer.org/about/where-we-work>

3.2.3 Co-op

Co-ops are a form of ownership in which a company is effectively owned by its members, who are normally its customers. They are incorporated under the laws of the state in which they operate. Such ownership forms are not limited to utilities; credit unions, for example, are a form of co-op.

Figure 3. Co-op principles



Source: National Rural Electric Cooperative Association

Electric co-ops can either be (i) generation and transmission ("G&T") co-ops, (ii) distribution co-ops, or (iii) both. G&T co-ops provide wholesale power to distribution co-ops through their own generation or by purchasing power on behalf of the distribution members while distribution co-ops deliver electricity to the customers. In the US, there are 834 distribution co-ops and 63 G&T co-ops serving an estimated 42 million people in 47 states.[15] The electric co-ops also own and maintain 2.6 million miles, or 42% of the nation's electric distribution lines.[16] They deliver 11% of

[15] National Rural Electric Cooperative ("NRECA"). "Electric Co-op Fact Sheet." Accessed on July 18, 2017. <https://www.electric.coop/electric-cooperative-fact-sheet/>

[16] Ibid.

the total kilowatt hours sold in the US each year and generate nearly 5% of the total electricity produced in the US each year.[17]

Cooperatives in the US operate according to the same set of core principles adopted by the International Co-operative Alliance. These principles are shown in Figure 3. Co-ops are democratically controlled by their members and governed by a board of directors. Therefore, they are autonomous and independent. Generally, co-op members have equal voting rights (one member, one vote basis). Some of the responsibilities of the board include setting major policies and procedures that are implemented by the co-op's management; advocating for the members; approving annual operating budgets, capital expenditure budgets, and compensation plans; recruitment and selection of CEO; and choosing independent auditor for the annual financial audit.

While co-ops have access to concessional financing via Rural Utilities Service ("RUS"),[18] National Rural Utilities Cooperative Finance Cooperation ("CFC"), and the National Cooperative Services Corporation ("NCSC"),[19] because they do not have equity other than retained earnings (profits which have not been returned to members), mobilizing funds can be more challenging than it is for IOUs. Co-ops also have tax advantages such as having the Federal tax-exempt status under the IRC section 501(c) (12) (provided that 85% or more of their annual income comes from members). Nevertheless, this also means that they are unable to take advantage of various incentives that are provided through the tax code, like investment tax credits ("ITCs"), accelerated depreciation, and production tax credits ("PTCs").

Whereas IOU management faces two forms of oversight (from shareholders through the board, and from regulators on behalf of customers), in most co-ops, its management has oversight by its board acting on behalf of customer members. There are also other co-ops, such as in Hawaii, where co-ops have oversight from regulators. Co-ops may face less pressure to seek efficiencies, but may benefit from a longer-term investment horizon which is more customer-centered.

[17] Ibid.

[18] An agency of the US Department of Agriculture.

[19] CFC provides financing to its members for non-profit services while NCSC can lend to members, non-members, and for-profit entities as long as the activity benefits the cooperative network.

Kauai Island Utility Cooperative ("KIUC") is an example of a co-op operating in Hawaii; promoters have put forward the idea of creating a co-op for the island of Hawaii as well.

Kauai Island Utility Cooperative: the only electric co-op in Hawaii

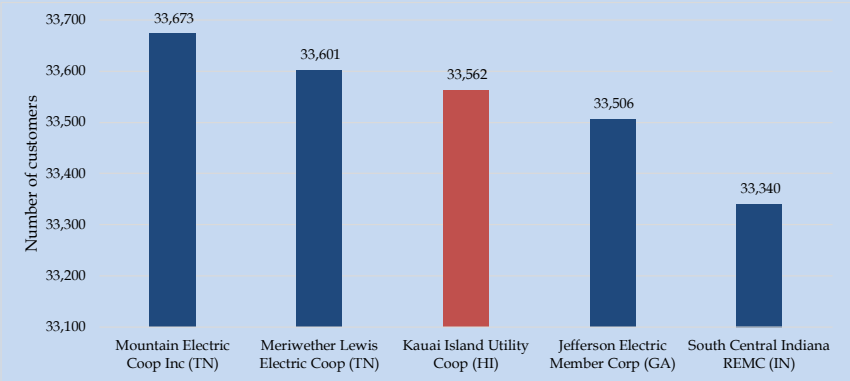
KIUC provides electric service on the Kauai island. On November 2002, KIUC became the first electric co-op in Hawaii when it purchased the electric utility from Citizens Communications.

Number of customers (2016): ~37,000

Total assets (2016): $380.467 million

Total revenues (2016):* $143.5 million

Comparators based on size (2015):**



Note:
** Operating Revenues; ** Most updated information available on the EIA Schedule 4*
Source: Kauai Consolidated Financial Statements (December 31, 2016 and 2015), KIUC website. EIA Schedule 4

3.2.4 Muni

Municipal utilities ("munis") are generally owned by cities and towns; across the US, there are 2,013 municipal utilities serving 15% of US customers.[20] Many municipal utilities arose out of public works departments in various cities and towns; over time, these assumed a separate corporate identity from the cities that own them and that they serve. Being municipally owned brings with it both advantages and challenges. Municipal utilities may benefit from access to tax exempt debt financing; they themselves may also be tax exempt, and exempt from various kinds of state and Federal regulations.

Austin Energy: A muni of similar size to HECO

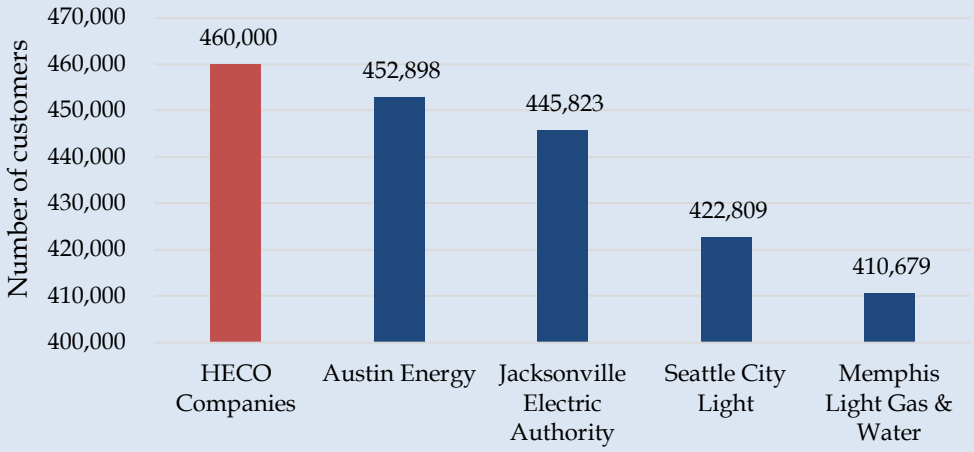
Austin Energy is a large municipal utility, serving a similar number of customers to HECO - more than 461,345 customers as of 2016. It operates within the Electric Reliability Council of Texas. The operations of Austin Energy are funded entirely through energy sales and services, and the utility further supports the City of Austin and its departments through an annual transfer into the general fund of more than $100 million.

Number of customers (2016): 461,345

Total assets (2016): 4,383 million (Electric Utilities)

Total revenue (2016): 1,370 million (Electric Utilities)

Comparators based on size (2015):*



*Note: * Number of customers in 2015 (except HEI's data in 2016). Most updated information available on the EIA Schedule 4 is 2015.*

Source: SNL, Velocity Suite, EIA Schedule 4

[20] American Public Power Association. *2015-2016 Annual Directory & Statistical Report.* <http://www.publicpower.org/files/pdfs/uselectricutilityindustrystatistics.pdf>.

However, municipal utilities can also face difficulties in recruiting employees with adequate technical skills needed to run a utility, if their employees are subject to the same rules and pay scales as other city employees. Municipal utilities can also be subject to political interference which may make it difficult to pursue long term strategies. In terms of governance, munis are governed by the city council or a local board. Utility rates and service policies are set by these local entities. In addition, the municipal utility may face pressure to transfer dividends to its municipal parent; in such circumstances, muni rates may be viewed as a substitute for tax revenues. This can make it more difficult for a muni to mobilize funds for investment. Like co-ops, the only source of equity for municipal utilities (unless the city chooses to inject funds) is retained earnings.

3.2.5 Hybrid, majority government owned

While examples of hybrid ownership models exist, in almost all cases, they arose from governments partially privatizing a utility which was formerly 100% government owned. A number of European utilities continue to have a high degree of state ownership. Likewise, in Asia, Malaysia's largest utility Tenaga Nasional Berhad ("TNB") continues to be 41.15% government owned. There are few examples of governments buying controlling stakes in existing private utilities that they do not intend to expropriate. Governments differ in how they hold their investments in utilities. In some cases, the shares are held directly by the relevant Ministry, indicating a greater desire to use the utility as a tool for implementing government policy. In others, the utility stake is held by a government-owned investment fund that employs professional managers to ensure that state-owned companies are managed competently and commercially. Singapore is an example of the latter approach.

State-controlled utilities generally have little trouble mobilizing funds. State ownership can present a "halo" effect where investors assume the utility has implicit backing from the government. One advantage that hybrids have is that unlike co-ops and munis, they can raise equity on the stock market instead of relying solely on retained earnings. However, there are limits to doing so if the government owner is concerned about dilution of its control. Some government owners, as in Ontario, have addressed this issue by capping the stake that any one entity can purchase; others, like the United Kingdom ("UK") after privatization, have retained a so-called "golden share" which allows them special rights, such as the ability to block a merger.

Hybrid entities generally are exempt from civil service restrictions and are somewhat insulated from political interference. However, if the government is not perceived to be a profit-maximizing shareholder, minority shareholders may place a lower value on the utility's equity. Public shareholders will be attentive to whether government ownership is depressing profits by directing the utility to undertake initiatives without a strong commercial basis.

Hydro One

Hydro One is an electricity transmission and distribution utility serving the province of Ontario in Canada. As of March 31, 2017, the province of Ontario owns 70.1% of the utility.

Number of customers: 1.3 million

- Transmission: 44 local distribution companies and 87 large industrial customers connected directly to the transmission network.
- Distribution: Over 1.3 million residential and business customers

Total assets (2016): Cdn$25.35 billion

Total revenues (2016): Cdn$ 6.552 billion (includes both regulated and unregulated businesses)

Note: Exchange rate in 2016 (average): US$ 1 = Cdn$ 1.325
Source: Hydro One Investor Fact Sheet – 2017 and Hydro One 2016 Annual Report

Tenaga Nasional Berhad

TNB is the largest utility not only in Malaysia but also in the Southeast Asia region. It serves customers in Peninsular Malaysia, Sabah, and Labuan.

Number of customers: 9.2 million

Total assets (2016): RM 132,902.2 million

Total revenues (2016): RM 44,531.5 million

Note: RM = Ringgit Malaysia
Exchange rate in 2016 (average): US$ 1 = RM 4.142
Source: TNB 2016 Annual Report

3.2.6 Integrated distributed energy resources ("IDER") system operator

An integrated distributed energy resources ("IDER") system operator represents a new approach to utility ownership.[21] While the regulatory aspects of this model will be reviewed in a subsequent working paper, there are also implications for ownership models. Under an IDER model, the "utility" is confined to the wires portion of the business, and is required to provide open access to all distributed energy resources ("DERs") connected to it at a price that recovers the utility's

[21] This does not currently exist in fully deployed manner. However, the State of New York is making moves to implement one.

costs. The utility or another entity may take on the role of coordinating flows across the grid. Generation would be moved to a competitive subsidiary, with appropriate consideration of stranded costs, if any. The utility may or may not provide a "standard offer" for DERs, who would be free to accept that standard offer or to contract with other customers bilaterally while paying for the use of the utility's lines. Under the IDER model, the utility would optimize the system, and in theory would have no incentive to discriminate against third party assets, or between DERs and transmission.

The IDER model presumes a diversity of ownership structures for generation, the potential for embedded or connected microgrids, use of new technologies like blockchain to allow peer to peer relationships, and the ability to optimize across a range of technologies and grid linkages. No one ownership structure for generation need dominate; community ownership, IPPs, former ratebase generation, and co-op or municipal generation could all co-exist. However, key to making such a structure work is properly unbundling existing utility costs and appropriately enforcing open access. These concepts will be discussed further in the regulatory models working paper.

New York's Reforming the Energy Vision ("REV")

In recognition of the rapid advancements in DER, the New York Public Service Commission ("PSC") initiated the Reforming the Energy Vision ("REV") proceeding which became a multi-pronged strategy of the state to develop a clean, resilient, and affordable energy system for all New Yorkers. It prioritizes energy efficiency and clean locally-produced power. It also encourages deeper penetration of DER and engages end-users through the creation of a more local, distribution network oriented market structure facilitated by utility as distribution system platform ("DSP") provider. The idea is to reform the traditional utility business model so that integrating DERs from third party providers is a crucial feature and to ensure that utilities are incentivized to consider DER solutions as an alternative to traditional grid investments.

The PSC directed the six large IOUs in the state to develop and file demonstration projects to test new approaches to distributed resource adoption. One of these demonstration projects is National Grid's DSP project with the Buffalo Niagara Medical Campus. In this project, National Grid is testing how it can integrate customer-owned energy resources to manage system demands. According to the implementation plan, this project is currently in "Technology Development" (Phase 2) stage of the project. The proponents are due to start the field demonstration (Phase 3) in September 2017 and they plan to complete the evaluation/report dissemination by October 2018.

Source: National Grid

3.2.7 Single buyer

There are a number of variants of the single buyer ("SB") approach worldwide. In some cases, the SB is set up as a stand-alone not-for-profit entity; in others, it is part of an independent system operator, or ISO; a third variant has the utility itself take on the role, while being forbidden from or constrained in the ability to bid its own projects into SB procurements. In Hawaii, an entity like

the proposed Hawaii Electricity Reliability Administrator ("HERA") could fulfill this role.[22] HERA could also take on the role of system operator as envisioned in the IDER model.[23] Alternatively, HECO Companies itself could be the SB, with appropriate safeguards to assure that they are operating in a fair and transparent manner. This would entail setting up a new legal entity to serve as the SB within the HECO Companies, which would be appropriately ring-fenced from other the HECO Companies operations.

Under the SB approach, generation ownership, as in the IDER model, could be diverse. If the SB is a stand-alone not-for-profit entity or an ISO, the SB itself does not own generation or wires assets; it is merely a contracting agency. The distinction, however, is that instead of seeking contracts bilaterally, all grid connected DER would have a contract with the SB. The SB would procure generation consistent with an integrated resource plan ("IRP") or other planning mechanism, similar to aspects of HECO Companies' PSIP discussed in greater detail below. Ideally, the SB would be technology and ownership model neutral, procuring at long run least cost for the system and passing its costs through to ratepayers. Technology neutral means that the SB would consider storage, and it would also assess tradeoffs between wires, generation, storage, and behind the meter solutions.

Ontario Power Authority/ Independent Electricity System Operator

On January 1, 2015, the Ontario Power Authority ("OPA") and the Independent Electricity System Operator ("IESO") were merged through amendments to the *Electricity Act*. It required the IESO to ensure "an effective separation of functions and activities relating to its market operations on the one hand and its procurement and contract management on the other hand."

Currently, the IESO procures renewable and clean energy from various generation technologies and capacities. The procurement method includes standard offer, bilateral negotiations, and competitive bids. As of March 2017, the IESO was managing 28,907 contracts with a combined capacity of 27,379 MW.

Source: IESO.

[22] We note that Act 166 authorizes the PUC to develop, adopt, and enforce reliability standards and interconnection requirements and to contract for the performance of related duties and with a party that will serve as the HERA, but does not include the SB functions mentioned here. Therefore, an amendment to the Act may be needed to include the SB and grid access oversight functions.

[23] In Singapore, the Energy Market Authority ("EMA"), is the electricity and gas industry regulator in the country. Like the PUC, EMA also takes the role of a Power System Operator ("PSO") and is responsible for the reliable supply of electricity to the consumers. Unlike the PUC, however, the PSO function of EMA cannot be contracted out to another entity.

3.2.8 Grid defection/disperse ownership

An integrated grid can provide significant benefits for consumers in terms of reliability, efficient financing, social insurance, and ease of transaction. However, current rate structures have challenges, which will be discussed in greater detail in the regulatory models working paper. Two key challenges which impact ownership structure are the role of historical cost accounting and pricing of optionality. Historical cost accounting, or "HCA," benefited ratepayers in a world of cost inflation, which to varying degrees persisted in over a century of utility ratemaking. As new, higher cost resources were integrated into the grid, higher costs were muted by being averaged with the existing cost of the system. Furthermore, if load was growing, and economies of scale continued to exist, even if equipment costs were rising, the benefits were spread over larger amounts of load, helping to manage costs.

These conditions no longer prevail. Costs for some forms of generation are falling rapidly, are available in smaller unit sizes, and may not have significant economies of scale. While grid defection today likely requires sacrificing reliability, the cost of back up is falling. Eventually, the cost of combined DER and storage will place an effective cap on what utilities can charge; grid connections will ultimately be seen by customers as an option and valued accordingly. HECO Companies have performed confidential studies of the potential for grid abandonment;[24] while the phenomenon may not be imminent, it is likely closer in Hawaii than it is on the mainland. [25]

Under a grid defection scenario, parts of the grid may need to be abandoned, meaning stranded costs could arise in both generation and wires. Grid services would atrophy, and the cost to serve underprivileged customers would rise. Generation ownership would be diverse, and microgrids, also under diverse ownership, would proliferate. Customers would effectively receive the level of reliability they wished to pay for, but ability to pay or access to knowledge to self-supply would be a challenge for some customers. Overall, this scenario would become more likely were there to be a combination of rapid cost declines, unwillingness to implement creative ideas on the part of the utility, and regulators' failure to consider, or slow implementation of innovative changes to rate design.

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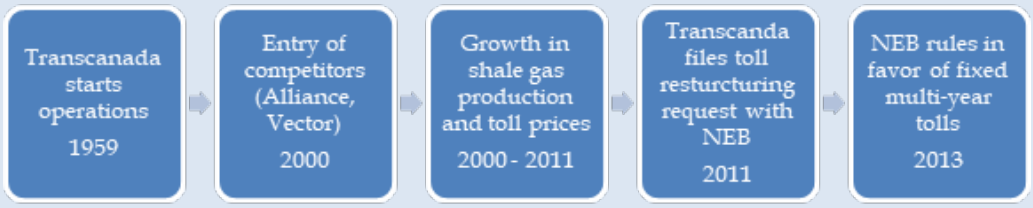
[24] HECO. *Power Supply Improvement Plans Update*. December 31, 2016. Book 4 Appendix Q: Customer Retention Economics. page Q-1.

[25] LEI is working on a paper on this topic for the International Association for Energy Economics. The paper will estimate the theoretical point at which grid parity would be reached for consumers in certain jurisdictions, the extent of cost declines, and the assumptions required to properly quantify grid parity estimates.

Lessons from TransCanada Mainline

A parallel example, although not a perfect analogy to this discussion, is emblematic of what happens when a formerly perceived firm as a natural monopoly is no longer one, is the case of the TransCanada Mainline. This example showcases the impact of competition on customer rates. TransCanada Mainline, one of the largest natural gas systems in Northern America, started its operations in 1959. Until 1998, TransCanada mainline was the sole provider of natural gas to the U.S. and Canadian markets and faced limited competition.

Starting in the 2000s, however, the competitive landscape began to shift as more competitors including Alliance and Vector pipelines began providing gas transmission services in the region. Due to the growing supply of gas, the amount of gas transported by the TransCanada Mainline significantly declined and resulted in substantially higher fixed costs and toll prices. In response, TransCanada presented a toll restructuring proposal to the National Energy Board ("NEB") in which it requested to shift $400 billion in yearly costs to users of the Alberta system. After further proceedings, the NEB decided to implement a long term fixed competitive price for tolls for a four-year period.



Source: TransCanada Mainline Decision.

3.3 Implications across the value chain

It is possible to mix and match ownership structures across the value chain; there are utilities, co-ops, and munis who own only wires, only generation, or combinations thereof. While for the sake of simplicity we have evaluated the ownership structures assuming that if they were adopted, they would be for the entire value chain, a large number of hybrid arrangements are possible. Below, we briefly discuss the extent to which different ownership structures would impact the amount and type of investment at different parts of the value chain. In the subsequent section, we explore other similarities and differences.

3.3.1 Generation

Five of the eight ownership models explored assume a significant continued role for the utility in constructing generation; the models differ only in the perceived motivations of the utility rather than in their function. Whether we consider the status quo, a new parent, a co-op, a muni, or a majority government stake, the utility's role in generation is unchanged; it builds generation under ratebase consistent with some form of IRP. Under each of these models, there is likely to be a bias in favor of generation relative to wires solutions if those wires solutions involve a greater number of participants in a permitting process; if generation can be built more quickly and with

fewer permitting complications, that is where the utility will focus its efforts. However, the presumption is that a new owner would move more aggressively to implement zero-emitting solutions and to replace existing assets. At this stage in the project, however, there is no substantive evidence to support this presumption. Furthermore, while the five utility-centric models differ in who ultimately receives the profits, under each, the capability and motivations of the management team may be as important as the ownership structure in determining actions.

Under the IDER and SB models, there is likely less of a bias towards generation. Under the IDER model, the utility's sole focus is on wires. Under the SB model, the SB is presumed to be acting in the public interest, which may facilitate permitting of wires projects; in addition, if it is tasked with preparing an IRP, it has no incentive to favor one type of asset over another since it does not own any assets.

The grid defection model, by definition, favors generation and combined generation and storage projects, though it may incorporate some microgrids.

3.3.2 Transmission and distribution

Given the unique nature of the island grids, the distinction between transmission and distribution is not meaningful in Hawaii. As such, we have assessed all grid-related investments together. Overall, our view is that the IDER model is the most supportive of wires investment; under IDER, grid investment is the only way for the utility to increase its ratebase, and indeed, in order to facilitate integrating diverse resources, it is likely to be encouraged to do so. Under the SB model, grid investment would be driven by the IRP; ownership of new grid investments would depend on whether there was an incumbent preference or not. For some types of grid enhancement, it may not be feasible for anyone but the incumbent to perform the investment.

Ownership models may also impact the potential for inter-island interconnection.[26] The IDER and grid defection models make inter-island interconnection least likely. The ownership and payment structure for the inter-island interconnection could differ from the status quo as well. The interconnection could be owned by a new investor; it could be a co-op of which HECO Companies, a for-profit entity, are a member; it could be state-owned. Under the SB model, the SB could hold a procurement for services in which the interconnection could compete against local generation, and the form of ownership would be subject to whatever the proponents saw as giving them the best chance of winning. Politically, however, any ownership structure which is not perceived as appropriately sharing the benefits (if indeed the interconnection is beneficial) is not likely to result in the requisite approvals to build it.

3.4 Similarities and differences

As noted below, one of the key differentiating features of the various ownership models is the role of the utility. In no case does the utility disappear; in each, however, there are differences in its objective function and how profits (or surpluses, in the case of a co-op) are distributed. While

[26] LEI notes that based on the initial stakeholder meetings, there is significant stakeholder opposition to inter-island interconnection.

the utility doesn't disappear, the role of the regulator changes. Were the ownership structure to become entirely co-op or municipal, the regulator would have less of an impact on setting rates or reviewing IRPs. In those instances, the regulator might still be involved in setting reliability standards and regulating access. In all other models, the regulator would still be heavily involved in setting rates, but it would also have a role in assuring the fairness of procurements under the SB model, and in assessing effectiveness of integration and equality of access under the IDER model.

Figure 4. Summary of similarities and differences

	IOU	New parent	Co-op	Muni	Hybrid	IDER	Single Buyer	Grid defection/ disperse ownership
Utility motivation								
• More bias towards generation	X	X	X	X	X			X
• More bias towards wires						X		
• Generation and transmission neutral							X	
Role of regulator								
• Regulates reliability standards	X	X	X	X	X	X	X	X
• Regulates rates	X	X	X*		X	X	X	X
• Ensures equality of access	X	X	X	X	X	X	X	X
• Ensures effectiveness of integration							X	
• Ensures fairness in procurement process							X	
Generation remuneration								
• Utility continues to be under ratebase	X	X	X	X	X		X	
• Another approach to rate design might need to be explored						X		X
Planning								
• Utility is responsible for generation and grid planning	X	X	X	X	X		X	
• Utility is responsible for grid planning						X		
• Regulator is responsible for grid planning								X
Taxation								
• Federal tax-exempt			X	X				
• State tax-exempt				X				
• Tax-exempt on debt financing				X				
Fund mobilization								
• Greater access to capital	X	X			X		X	X
• Retained earnings are primary source of equity			X	X				

** Note: In Hawaii, the PUC regulates the rates of the KIUC, which is not common among other co-ops.*

Responsibility for planning also differs among the models. Under the status quo and the other utility centric models, the utility is responsible for planning with oversight from the regulator.

Under the IDER model, utility planning likely shifts to planning of the legacy grid, with market forces driving generation location and planning – but some backstop planning for reliability is likely required and may remain with the utility. Under the SB model, the SB is likely responsible for planning. Of course, in a grid defection world, planning becomes challenging as the utility will increasingly lack the means of implementing the plan. In such a world, planning likely defaults to the regulator and focuses on access for low income customers.

Another area of distinction is generation ownership and remuneration. Under the utility centric models, generation would continue to be under ratebase and could be developed by the utility. Under the IDER and SB models, generation would not be developed under ratebase. In the IDER model, while non-regulated utility affiliates could participate in generation, they would be subject to greater scrutiny to assure a level playing field. By contrast, in the SB model, provided the utility itself was not the SB, non-regulated utility affiliates would face less scrutiny because there would be less opportunity for favoritism.

One potential area of distinction is taxation. While various so-called "payment in lieu of taxes" or "PILOT" programs can be designed, co-ops and munis face different treatment with regards to property, local, state, and Federal taxes. Without a PILOT program, creation of a co-op or muni can result in loss of local and state tax revenue.[27] Because the IDER and SB models involve greater participation by non-utilities, the impact on any taxes collected through the utility would need to be assessed. Because under the grid defection model both utility sales and sales for resale would be less, tax revenue would need to focus on sales of DER equipment.

3.5 Steps required for formation

While no additional steps are required to maintain the status quo, each of the other ownership forms would require a series of actions to implement. The description below is not intended as a detailed implementation plan for any of the alternatives; rather, it is intended to touch upon major groups of activities that would be necessary if such an ownership structure were to be considered. It also does not constitute legal advice or analysis. Some steps may be more challenging than others; feasibility will be discussed later in the project. A key issue is how a new owner takes control of current HECO Companies' assets; for the purposes of the analysis below, we assume that this is on a negotiated, friendly basis. While a new commercial owner could pursue a hostile takeover, this would require paying a higher premium and obtaining backing of existing institutional shareholders. In the case of munis, expropriation through condemnation proceedings is time consuming and acrimonious, with uncertain outcomes.

3.5.1 New parent under IOU

To facilitate a new parent, a buyer would need to be either identified or created and funded. However, it is a long and costly process for the potential acquirer and there is a regulatory risk that the transaction will not be approved, similar to the proposed NextEra acquisition. Furthermore, the entity doing the recruitment of the new buyer is difficult to identify. In this case, we assume the creation of a Governor's Task Force with specific terms of reference as to how to

[27] While Federal taxes would also be impacted, this is outside of our scope except to the extent that it impacts rates.

attract or create a new parent, which would then in turn negotiate a friendly takeover of the utility.

An indicative list of steps is as follows:

- ✓ Form Governor's Task Force
- ✓ Develop terms of reference
- ✓ Issue request for expression of interest based on terms of reference
- ✓ Assess which an existing for profit or not-for-profit entity is willing and capable of acquiring the HECO Companies
- ✓ Determine whether state will provide any support for such a bid, and how such support would be funded
- ✓ If no suitable party is identified, or if such party is unable to negotiate with the HECO Companies or initiate hostile takeover,[28] assess whether an acceptable bidder can be created
- ✓ If such a bidder can be created, set up the entity, create governance procedures, staff it, and commence negotiations
- ✓ Obtain financing, close an acquisition

[28] One of the takeover defenses that HEI has is the staggered terms of its Board of Directors. Having a Board with staggered terms in which groups of directors are elected at different times for multiyear terms can challenge the prospective acquirer. The potential acquirer must succeed in multiple proxy fights over time and deal with numerous shareholder meetings to successfully take over the utility.

How much would it cost to buy HECO Companies today?

Estimated Cost of HEI:[1,2] $3.7 billion

Calculated using:

- Current stock price:[3] $32.02 per share
- Number of shares:[3] 108,750,455 shares
- Assumed premium: 5%

Estimated Cost of ASB:[4] $1.3 billion

Calculated using:

- Estimated Market Price Per Share of ASB only:[6] $12.05
- ASB's Book Value per Share:[7] $5.48
- Average Price to Book Ratio of similar banks:[8] 2.20

Estimated Cost of HECO Companies:[5] $2.1 billion

Amount offered by NextEra: $4.3 billion (in 2014)

Note:
** This is just a back of the envelope calculation*
[1] This assumes buying the HEI entirely, including the American Savings Bank ("ASB").
[2] LEI does not foresee KIUC being acquired by an IOU and therefore estimated cost of acquisition is not estimated.
[3] As of July 17, 2017
[2] Assuming debt unchanged at the holding company level, the net debt (as of latest filing) is $346.25 million
[4] The estimated cost of ASB is estimated by multiplying the total number of HEI shares by the estimated ASB market price per share.
[5] Estimated cost of the HECO Companies is calculated by subtracting the Cost of ASB from the Cost of HEI.
[6] The ASB market price per share is derived by multiplying the price-to-book ratio ("P/B ratio") of similar banks and ASB's book value per share.
[7] ASB's book value per share is calculated by ASB's total assets less total liabilities divided by number of shares outstanding as of July 17, 2017
[8] Average price-to-book ratio of similar banks is derived by getting the P/B ratio of similar banks as of July 17, 2017. Similar banks were chosen based on similar function as ASB and ASB's total deposits and total assets as of the latest filing. These banks include American Savings Bank Corporation, Bancfirst Corporation, Farmers and Merchants Bank, Servisfirst Bancshares Inc. S&T Bancorp, WSFS Financial Corp, and Eagle Bancorp Inc.

Source: Bloomberg and HEI website, iBankNet.Com, and NextEra.

3.5.2 Co-op

Unlike the new parent approach above, creation of a co-op would likely involve an asset purchase rather than a share purchase. As noted previously, this could include all assets, or just those at a specific point on the value chain. It could also be for all HECO Companies' subsidiaries, or

county-specific, which would likely entail focusing on specific HECO Companies' subsidiaries. Steps to implement are as follows:

- ✓ Form co-op
- ✓ Recruit board
- ✓ Value assets
- ✓ Arrange financing
- ✓ Negotiate with HECO Companies
- ✓ Recruit management, which may or may not include some or all of existing HECO Companies' management
- ✓ Identify staff to be hired by co-op
- ✓ Establish rates
- ✓ Close acquisition

3.5.3 Muni

Creation of a muni would likely be county specific. Many of the steps are similar to creation of a co-op as described above, though theoretically a stock purchase of a HECO Companies' subsidiary would also be possible.

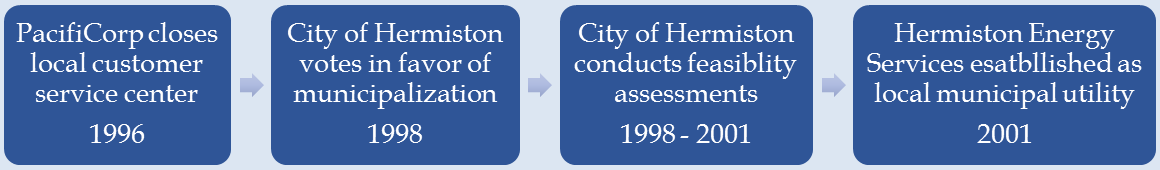
- ✓ Vote in city council to proceed with municipalization
- ✓ Assess rights in existing agreements
- ✓ Create framework and process for ratemaking and for dividend distribution
- ✓ Recruit board
- ✓ Value assets
- ✓ Arrange financing, including potential issuance of municipal bonds
- ✓ Negotiate with HECO Companies
- ✓ Recruit management, which may or may not include some or all of existing HECO Companies' management
- ✓ Identify staff to be hired by municipal utility; determine whether existing bargaining agreements impact hiring decisions
- ✓ Establish rates

✓ Close acquisition

Hermiston Energy Services: An example of a successful municipalization

In October 2001, the City of Hermiston, Oregon ("the City") formed a locally-owned municipal utility, Hermiston Energy Services ("HES"), following four years of efforts to determine the feasibility and benefits of municipal electric service. The municipalization decision, which took place in September 1998, was driven by the incumbent IOU's (Pacific Power & Light's ("PacifiCorp")) declining customer service performance following the closing of its local office. PacifiCorp assets within the City of Hermiston's service territory were acquired by the City through a negotiated purchase process following a condemnation proceeding in which the City ruled in favor of municipalization. The City of Hermiston paid $8 million in cash for the acquisition, a purchase price twice the amount of PacifiCorp's Net Book Value of its assets at the time. HES now serves close to 4,900 meters within the city limits of Hermiston and contracts out services including maintenance, meter reading and billing, and customer services to Umatilla Electric Cooperative, a cooperative located in the City of Hermiston. The city maintains the final decision making regarding utility rates, policies, and procedures. Since it started operation in 2001, the average residential rate has declined by 3 to 9% compared to rates charged by PacifiCorp prior to municipalization.

Timeline of the municipalization



Source: Public Utility Commission of Oregon, APPA.

3.5.4 Hybrid, majority government-owned

In creating a hybrid, a majority government-owned entity would first require conceptualization of what entity would own the majority stake and how that entity would be governed. For the purposes of this exercise, we assume that a new state authority would be created with its own board. It is important that the authority be sufficiently arms-length from the government such that after it is set up, it is insulated from day-to-day political pressures while remaining broadly responsive to specific public policy initiatives. It is possible that the body would be lightly staffed, potentially with as few as three staff (an administrator, an analyst, and an assistant).

- ✓ Adjusting for the calculations presented above to account for purchase of only a 51% stake; the total cost as of July 17, 2017 would be $1.9 billion
- ✓ Determine charter for state entity describing its mandate
- ✓ Establish state entity and appoint board members, who would also take board seats at HECO Companies
- ✓ Hire administrative staff
- ✓ Fund and purchase controlling interest through open market purchases on stock exchange and negotiated stakes with key institutional investors
- ✓ Determine procedures for day to day interactions with HECO Companies

- ✓ Negotiate with HECO Companies to assure that board representation was consistent with shareholding

AGDC: An example of a majority government-owned entity

The Alaska Gasline Development Corporation ("AGDC") is an independent public corporation owned by the State of Alaska. Its vision is to maximize the benefit of Alaska's North Slope natural gas resource through the development of infrastructure necessary to move the gas into local and international markets. In addition, it is responsible for developing an Alaska liquefied natural gas ("LNG") project on the State's behalf and is also directed to assist the Department of Revenue and the Department of Natural Resources in maximizing the value of the state's gas.

AGDC is a separate and distinct entity from the State and is structured within the Department of Commerce, Community, and Economic Development (for administrative purposes). It is governed by a board of directors composed of public members (5) and principal department head (2) of the State of Alaska. The board members are appointed by the governor and subject to legislature's confirmation. Public members serve five-year terms and are appointed on a staggered basis. The AGDC receives its multi-year funding appropriated by the Legislature to fund the State's equity participation in the Alaska LNG project.

In January 2017, the AGDC, formally took over the leadership position for the Alaska LNG project ("the Project"). The Project was originally proposed jointly by ExxonMobil, ConocoPhillips, BP, and TransCanada in 2012. By the time the formal agreement was reached, the stakeholders had spent more than $500 million on the Project. The State of Alaska's decision to take over the Project was primarily driven by ExxonMobil, BP, and ConocoPhillips's signaled reluctance to proceed with prior implementation plans given the global decline in LNG prices.[1] The leadership takeover agreement was based on AGDC's formal agreement with ExxonMobil, BP, and ConocoPhillips. The Project which is expected to cost $500 million will involve the construction of an 800-mile pipeline designed to export up to 20 million metric tons of LNG annually.

AGDC formally signed a Cooperation Agreement with BP to collaborate in the development of the financial and tolling structure. Later in June 2017, AGDC signed a memorandum of understanding("MOU") with Korea Gas Corporation ("KOGAS") to establish formal cooperation channels in the investment, development, and operations of the Project.

Source: AGDC

3.5.5 Integrated distributed energy resources ("DER") system operator

Moving to an integrated DER system operator necessitates piloting new and different ways to operate the electricity system and work with third-party DER providers. It also requires having a different business model for the utility. It is important to note that if adopted, theoretically, both the IDER and the SB model should apply regardless of the ownership structure of the underlying utility. Thus, both IOUs and co-ops would be subject to their establishment.

Steps to implement the IDER are as follows:

- ✓ Investigate current approach to dispatching resources on the distribution grid, including infrastructure, staffing, protocols, and information flows

- ✓ If utility is unwilling to divest or appropriately ring-fence its existing generation, require utility to contract out the IDER function to a third party if creating affiliate relations codes is insufficient to overcome potential conflicts of interest and level playing field issues

- ✓ Put in place appropriate economic arrangements for existing generation which is not governed by existing power purchase agreements ("PPAs")

- ✓ Create a new Grid Code for the state which sets forth the process by which resources are dispatched and how open access to the distribution system will be maintained

- ✓ Establish a corporate body that will hold all of the information technology infrastructure, control rooms, etc. necessary to coordinate flows on the distribution system, and that will direct all employees who perform this function

- ✓ Develop a distribution use of system ("DUOS") charge that will facilitate wheeling within the distribution system

- ✓ Install independent board to oversee the IDER ISO function

- ✓ Recruit any employees who are not being seconded from the utility

- ✓ Assure that the planning function for future generation rests with the IDER ISO and not the utility

3.5.6 Single buyer

- ✓ Establish single buyer as a separate corporate entity

- ✓ Create an independent board for the SB

- ✓ Hire such staff as are needed and not seconded from the utility

- ✓ Assure that future planning responsibilities rest with the SB and not the utility

- ✓ Create single buyer rules to govern the operation of the SB market and conduct of participants and to outline the functions, roles, and governance of SB

- ✓ Create ring fencing requirements such as separation of SB accounts and operations and functional autonomy (if utility is also the SB)

- ✓ Create Code of Conduct or guidelines in the conduct of SB employees in performing their functions (if utility is also the SB)

- ✓ Develop procurement plans consistent with PSIP or other approved documents which are ownership neutral and provide for a fair and transparent means of procurement.

3.5.7 Grid defection/disperse ownership

The process of grid defection is a reactive, rather than proactive, phenomenon. It is what is likely to occur over time if no action is taken to encourage alternative ownership models. Consequently, there are no steps that can or should be taken to encourage this. Indeed, the purpose of exploring other ownership and regulatory models is to attempt to prevent uneconomic grid defection – circumstances in which individual customer actions produce negative externalities such that while the individual may be better off, society as a whole is worse off, and potentially significantly worse off if a significant number of customers engage in defection.

4 Evaluation of ownership models relative to state criteria

The evaluation of ownership models relative to state criteria is at this stage of the project both qualitative and high level. Results are subject to refinement and change as the project proceeds and feedback from stakeholder groups and quantitative analysis becomes available.

The scoring mechanism is intended as a thought exercise in comparing the various ownership structures. Each utility ownership model was ranked from the most favorable to the least favorable. The scoring also does not differentiate between instances in which items were close in ranking versus widely different. It should be noted that this is purely illustrative and may be adjusted as the result of subsequent stakeholder consultations.

4.1 Ability to meet state energy goals

Hawaii has the most aggressive renewable energy targets in the country. It aims for its utilities to achieve 100% of their electricity from renewable energy by 2045.[29] In addition, Hawaii's energy policy focuses on its "commitment to maximize the deployment of cost effective investments in clean energy production and management for the purpose of promoting the State's energy security."[30] More specifically, the State aspires to achieve a diversified energy portfolio that make the best use of land and resource; have an efficient marketplace that is beneficial to all and integrated and modernized grids; and be recognized as an energy innovation center.[31]

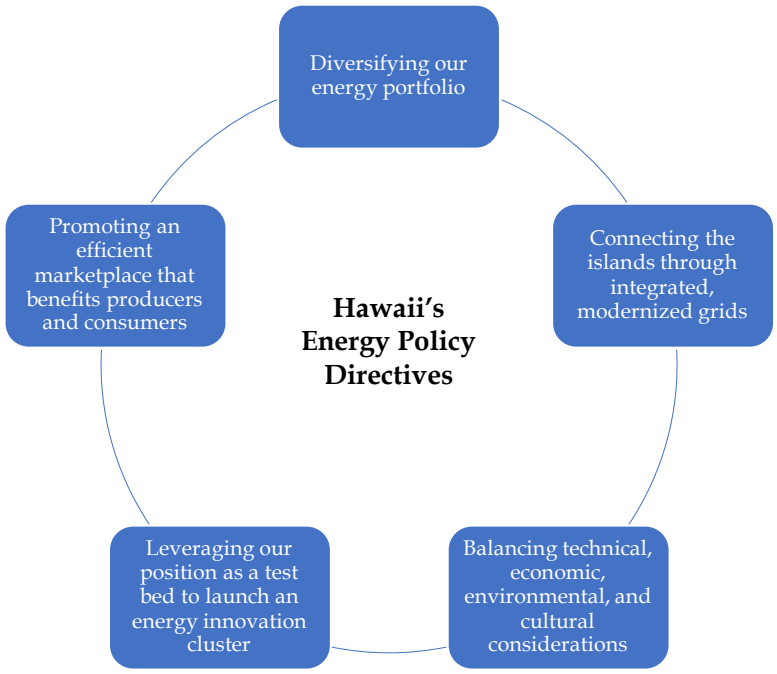
While many of the ownership models can be made to meet most or all of the state's objectives, they differ in terms of effectiveness and the extent of regulatory intervention required. Ironically, government ownership forms (state control or muni ownership) may have greater challenges, given the potential susceptibility of these forms to short term political pressure. Grid defection is also a poor means of meeting the state's goals because although it would achieve diversification of energy resources, it would not be able to meet the other objectives shown in Figure 5. Our illustrative scoring suggests that the IDER and SB models would best help the state meet its objectives because they would be independent but guided by state policies. The IOU was ranked third because, if properly regulated, an IOU is at arms-length from stakeholders and the profit motive can be directed by the regulator towards the objectives most meaningful to the state.

[29] HI Rev Stat § 269-92 (2015).

[30] HI Rev Stat § 269-92 (2015), Hawaii Senate Bill 198 (December 1, 2011), and Hawaii State Energy Office. Energy Policy. Accessed on July 20, 2017. http://energy.hawaii.gov/energypolicy.

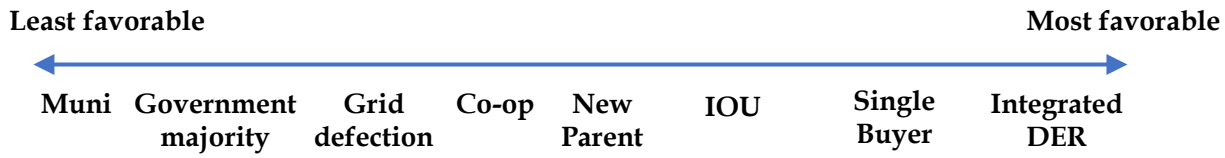
[31] Ibid; Hawaii House Bill 416 (January 26, 2015), and House Bill 1494 (December 17, 2015).

Figure 5. Hawaii's energy policy directives



Source: HI Rev Stat § 269-92 (2015), Hawaii State Energy Office ("HSEO")

Figure 6. Position of each model in the scale in terms of its ability to meet state goals



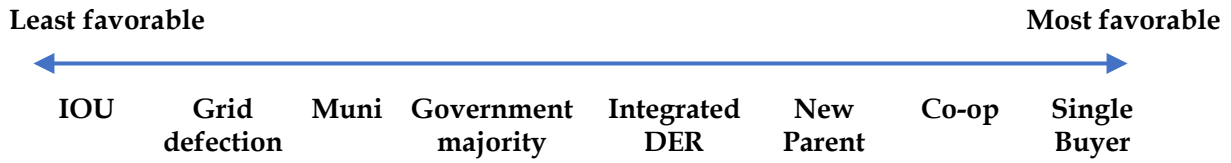
4.2 Maximize consumer cost savings[32]

The SB is the most favorable on the ability to maximize consumer cost savings because it is an independent body focused on long term least cost procurement. The co-op model scored second because of its ability to share surpluses with members, though there is the possibility that the co-op management may not always pursue long term least cost initiatives because the co-op' priorities are driven by its members-consumers' interests and needs and these might not always be the least cost. The IOU model is least favorable, largely due to the incentives under cost of service regulation to over-capitalize the system. However, as noted above, if the profit motive can be appropriately harnessed, IOUs can be an effective means of delivering state policy. Munis rank low in this category primarily because of the risk that they will face pressure to pay above-market wages due to civil service rules and political considerations. Grid defection will not

[32] The consumer cost savings considered in this section excludes consideration of implementation costs.

maximize savings; indeed, for those customers who remain with the utility, grid defection will mean a substantial increase in costs.

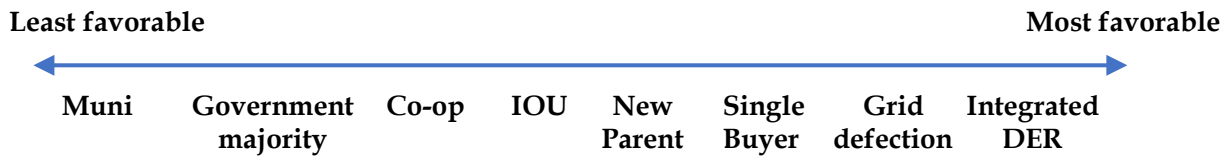
Figure 7. Position of each model in the scale in terms of its ability to maximize consumer cost savings



4.3 Enable a competitive distribution system

None of the traditional approaches to utility ownership models will enable a competitive distribution system. IOUs, munis, and co-ops all contain bureaucracies inimical to promotion of new types of generation ownership, evolving ways to connect consumers, and bi-directional flows on the distribution system. The IDER approach is the best way to create the distribution network of the future, as it explicitly targets created a competitive distribution system. While grid defection ranks second in this category, it lacks the benefits of coordination that an IDER structure would bring. Although the SB model would also facilitate competition, it retains a centralized approach to procurement which could undermine initiative and creativity.

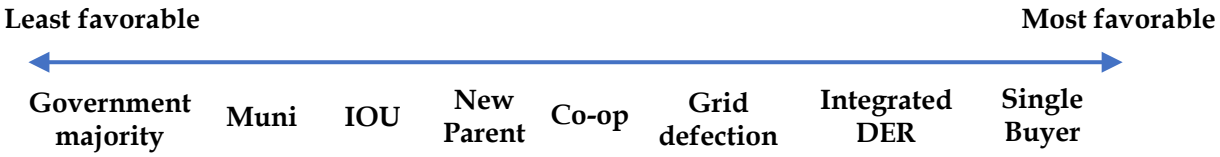
Figure 8. Position of each model in the scale in terms of its ability to enable a competitive distribution system



4.4 Address conflicts of interest

Addressing conflicts of interest requires as much as possible separating planning and operational control from investment and ownership. Thus, many of the mechanisms which score well under the objective of creating a competitive distribution system also score well in addressing conflicts of interest. Even though grid defection is ranked relatively highly in this metric, this may not be socially optimal. While those defecting from the grid entirely pay their full costs, they clearly no longer participate in a shared endeavor that allows for optimization among customer classes. This is why grid defection scores so poorly in the next category, aligning stakeholder interests.

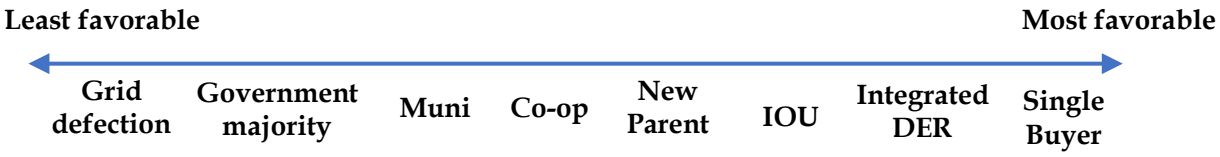
Figure 9. Position of each model in the scale in terms of its ability to address conflicts of interest



4.5 Align stakeholder interests

The extent to which any of the alternatives helps to align stakeholder interests partly depends on the regulatory framework in which it is embedded. Thus, while the separation of ownership, procurement, and operation principle continues to apply, we have not ruled out the possibility that a properly regulated IOU could align stakeholder interests; this could particularly be the case under new ownership by a public benefit entity. As noted above, grid defection fails to align stakeholder interests and would be the poorest of all the alternatives in this regard.

Figure 10. Position of each model in the scale in terms of its ability to align stakeholder interests



4.6 Incorporating transition costs

In addition to the state goals discussed above, we are also adding another criterion, which is the transition costs. While arguably embedded in consumer cost savings, it is important to note that the various ownership structures differ substantially in transition costs. Depending on how entrenched the opposition from the utility, any transition may be subject to delay and litigation. The status quo (or IOU) would provide the lowest transaction costs while the grid defection would provide the highest transaction costs due to potential stranded costs. A cordial, negotiated solution would minimize transition costs, even in those more complex solutions such as the IDER ISO approach. One possibility to reduce transition costs could be a phased approach, for example one in which the utility serves as the SB while an IDER ISO is being established.

Figure 11. Position of each model in the scale in transaction costs



5 High level needs assessment

As part of Task 1.1.1 "Introduction to Ownership Models and Asset Identification", LEI has reviewed publicly available information from the Hawaii electric utilities (such as regulatory filings, the PSIP, annual reports, strategic plans, and news articles), as well as third-party databases that LEI is subscribed to, to conduct a high-level needs assessment for infrastructure development through 2045.

Our high-level needs assessment relies on HECO Companies' PSIP[33] and KIUC's publicly available information (such as the KIUC Strategic Plan Update 2016-2030[34]) as the foundation for determining future Hawaii investment needs. To develop the PSIP, HECO Companies spent significant efforts, conducted multiple analyses (optimization, infrastructure, and financial), and obtained feedback from key stakeholders to develop near term resource plans and a set of possible long-term plans to achieve the 100% renewable target by 2045. Where appropriate, LEI has commented on assumptions that might need to be tested in the future.

For the state of Hawaii, the HECO Companies and KIUC together plan to add more than 850 MW of new renewable generating capacity in the next 5 years, which will require approximately $3-4 billion of capital investments.[35] In addition, HECO Companies filed a grid modernization plan in August 2017, which is estimated to cost about $205 million over six years.[36] By 2045, Hawaii electric utilities plan to invest between $15 and $21 billion to add over 2,450 MW of new renewable capacity.[37] However, as with any such plans, both are still subject to change as circumstances evolve. Furthermore, while the PSIP was prepared under status quo ownership arrangements, there is no evidence that it would be substantially different if prepared under other ownership models.

5.1 Existing capacity in the State

As of 2017, the total installed capacity for the State of Hawaii is at approximately 2,770 MW. Currently, Hawaii is heavily dependent on oil and diesel production: about 71% of Honolulu county's generation capacity, about 77% of Maui County's, and about 73% of Hawaii County's. In addition, more than 60% of the state's capacity is in Honolulu county.

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[33] PUC accepted the PSIP on July 14, 2017.

[34] Approved by KIUC's Board of Directors on January 31, 2017.

[35] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 1, Chapter 5.

[36] HECO Companies. *Modernizing Hawaii's Grid for Our Customers*. August 2017 Draft Report. Page ES-2.

[37] Capital expenditure projections for power supply, Smart Grid, ERP, and all other utility capital expenditures (referred to as "balance-of-utility business capital expenditures") are included in the analysis. Source: HECO. *PSIP Update Report.* December 23, 2016. Book 1, Chapter 5.

Figure 12. State's installed capacity by fuel type and county (2017)

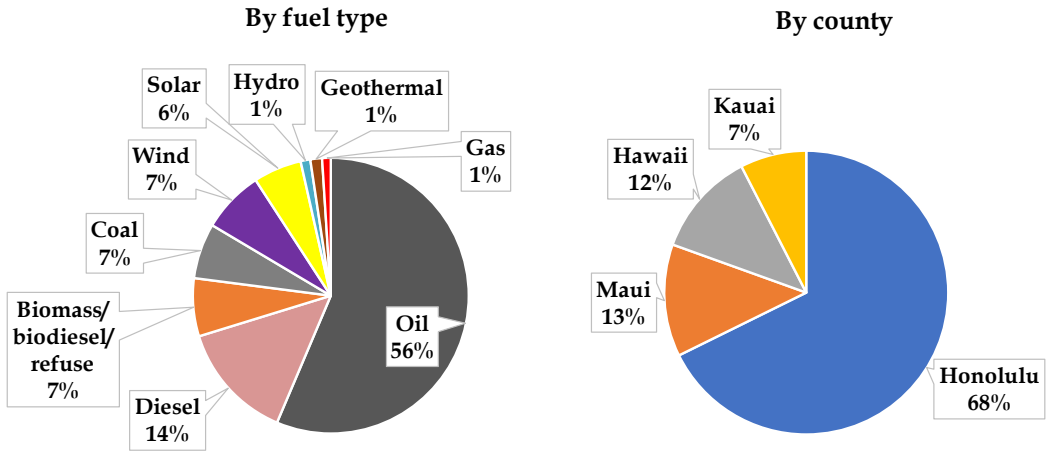
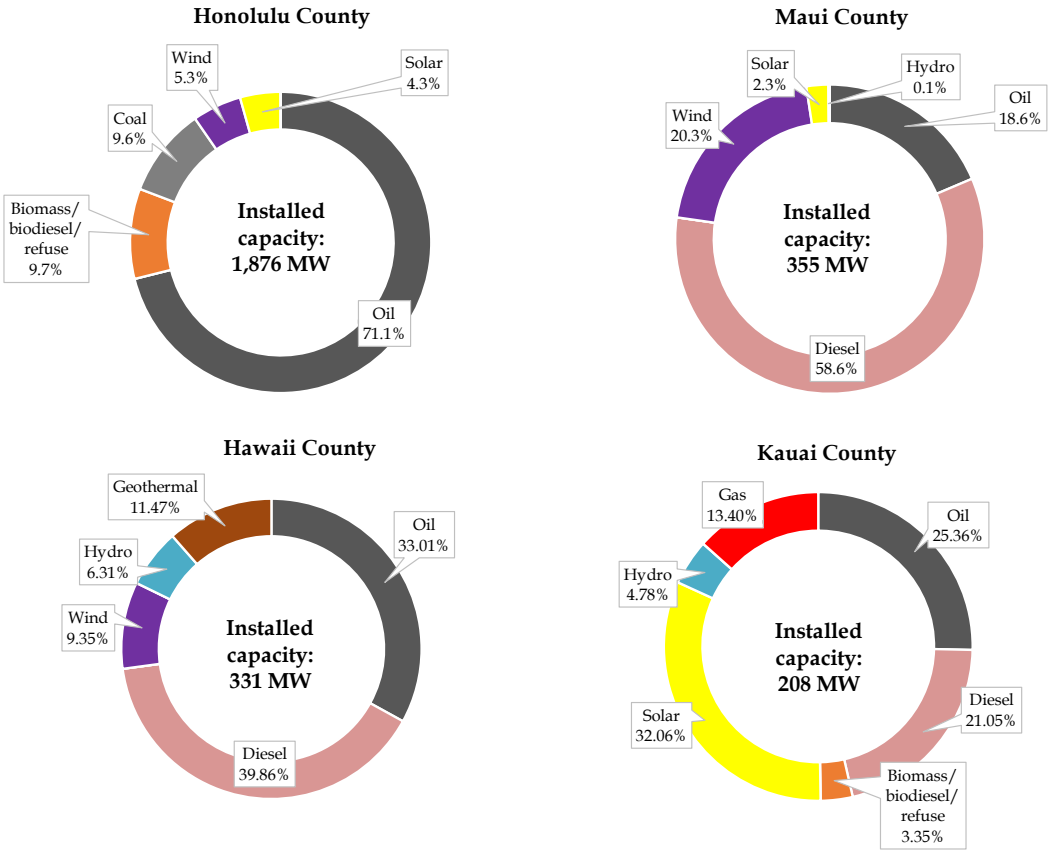


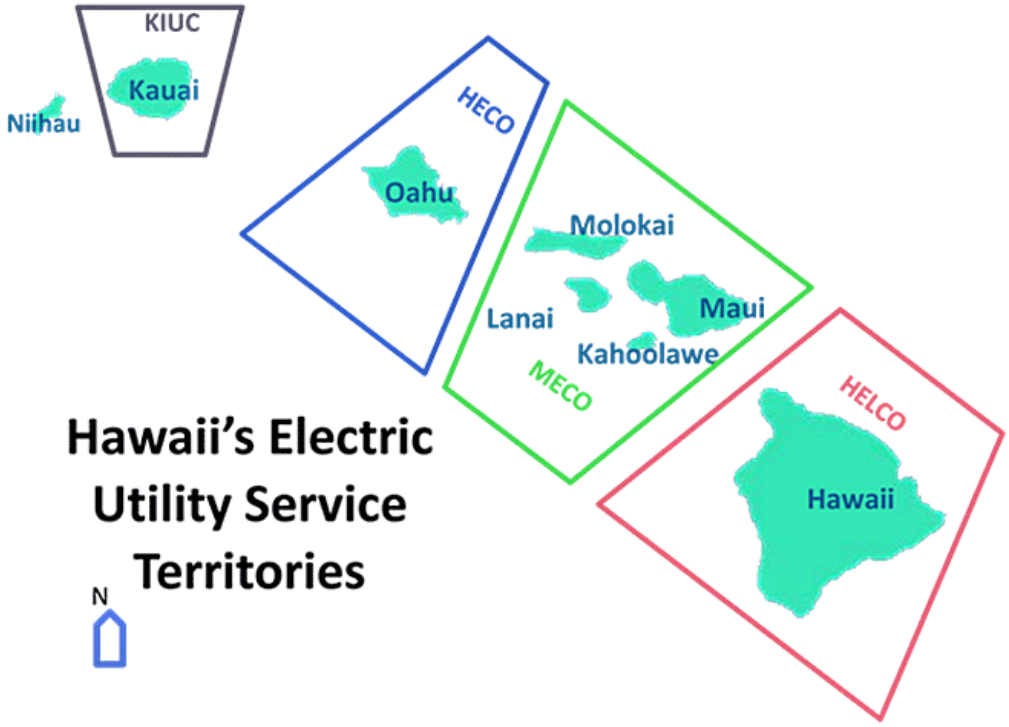
Figure 13. Installed capacity by county (2017)



Sources: HECO Companies, PSIP Update Report: December 2016, Book 1 (Executive Summary, Chapters 4 and 6) and Book 2 (Appendix D) and KIUC. "Energy Information." Webpage, last accessed July 21, 2017. <http://website.kiuc.coop/content/energy-information>

Each of Hawaii's six main islands has its own electrical grid, not connected to any other island. HECO Companies, HECO, MECO, and HELCO serve about 95% of the Hawaii State's electric utility customers. As shown in Figure 14, HECO serves the Honolulu County on the island of Oahu; MECO serves the Maui County on the islands of Maui, Lanai, Molokai, and Kahoolawe; and HELCO serves the Hawaii County on the island of Hawaii. Kauai County on the island of Kauai is served by KIUC, although KIUC is not included in the PSIP report.[38]

Figure 14. Hawaii's electric service territories



Source: Hawaii State Energy Office. "Hawaii Energy Facts & Figures." November 2016. Page 19. <http://kauai.coopwebbuilder.com/sites/kauai.coopwebbuilder.com/files/schedule_q_eff_092012.pdf>

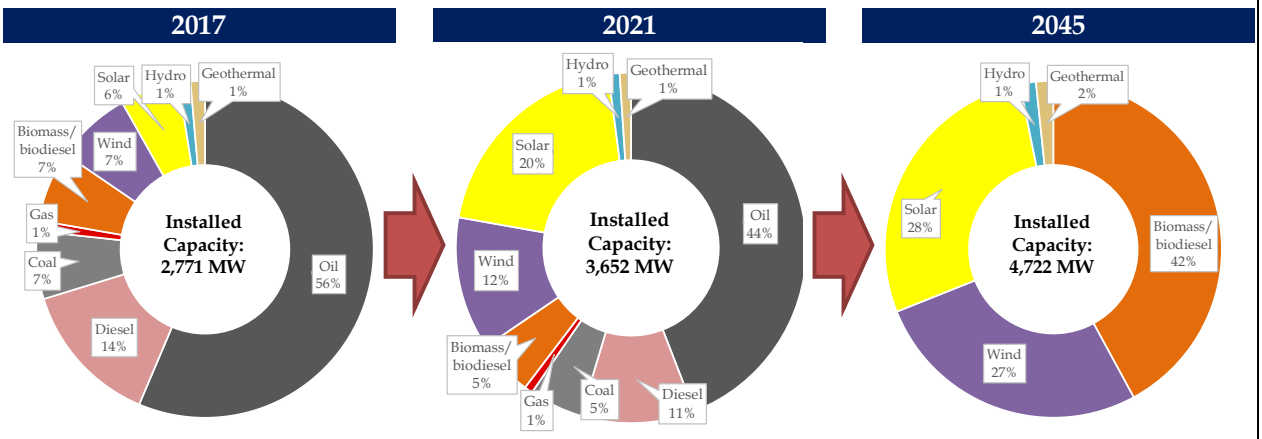
5.2 Assessment of near-term and long-term plans

As of 2017, a majority (about 78%) of the generating capacity in the state relies on oil, diesel, coal, or gas. By 2021, the current plans of the HECO Companies would decrease the state's reliance on thermal-fired generation by about 17%, bringing it down to 61%. The target energy system of Hawaii by 2045 is projected to be supplied primarily by biomass or biodiesel (about 2,000 MW),[39] and by approximately equal amounts of solar and wind (roughly 27%-28% each).

[38] Hawaii State Energy Office. "Hawaii Energy Facts & Figures." November 2016. Page 4.

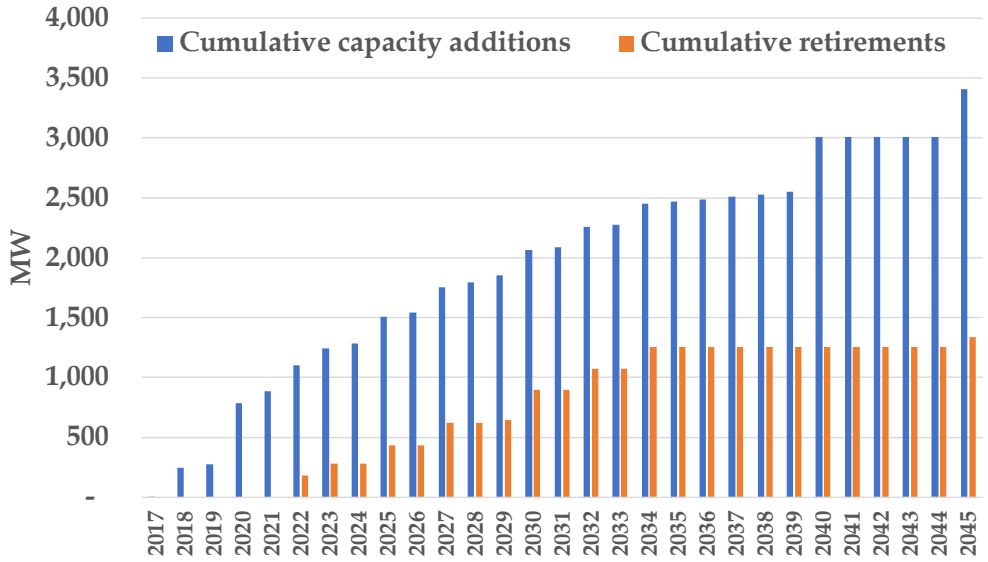
[39] This assumes that those plants that are currently not reported to be retired will be converted to biomass/biodiesel.

Figure 15. Hawaii State planned installed energy supply transition to achieve 100% RPS goal



Sources: HECO Companies, PSIP Update Report: December 2016, Book 1 (Executive Summary, Chapters 4 and 6) and Book 2 (Appendix D); HECO-913. DOCKET NO. 2016-0328. PAGE 1 of 1. Table "Hawaiian Electric Company, Inc. 2017 TEST YEAR. Age of Generating Units – as of: 2017;" and KIUC. "Energy Information." Webpage, last accessed July 21, 2017. Note: based on the Post-April PSIP long-term plan; assuming all remaining gas/oil/diesel plants converted to biodiesel by 2045.

Figure 16. Planned new entry and retirements in the State of Hawaii (2017-2045)



Sources: HECO Companies, PSIP Update Report: December 2016, Book 1 (Chapters 4 and 6) and Book 2 (Appendix D); KIUC, "Renewable Energy Projects," Webpage, last accessed July 21, 2017; SNL Financial; and third-party commercial database

5.2.1 Summary of HECO Companies' long term plan options

Developed by the HECO Companies, the PSIP details the HECO Companies' near-term resource plans (2017-2021) and long-term plan options to achieve 100% of power supply coming from renewable sources by 2045.[40] The updated PSIP was submitted to the PUC on December 23, 2016

[40] HECO Companies. *PSIP Update Report*. December 23, 2016. PUC Docket 2014-0183.

(Docket 2014-0183), which the PUC accepted on July 14, 2017,[41] directing HECO to implement the near-term plans.[42] Previously, the PUC had rejected the first version of the PSIP from August 2014,[43] and rendered moot[44] the second version from April 2016 when it dismissed the utilities' merger with NextEra Energy.[45]

Based on the PSIP, by 2021, the following plants are planned to be added to the counties served by HECO Companies:

- nearly 874 MW of new renewable generating capacity (which includes grid-scale solar, distributed generation PV[46], grid-scale wind, and FIT);[47]
- about137 MWh of storage;[48] and
- about 115 MW of demand response program resources.[49]

Furthermore, from 2021 to 2045, HECO Companies propose to convert over 1,000 MW of oil and diesel generation resources to biodiesel. In addition, they also plan to install nearly 2,400 MW of new diverse renewable resources (biomass/biodiesel, wind and solar, including grid-scale, hydro, and geothermal) and to add another approximately 70 MW of demand response. To maintain reliability of the system, the PSIP includes plans to add energy storage resources (137 MW in the first five years and about 380 MW in the following 24 years) and other grid technologies (e.g., adding 169 MVA of synchronous condensers by 2021), in addition to enhancements to the grid infrastructure, to integrate all the renewable resources.[50] Figure 17, Figure 18, and Figure 19 show the planned new entry and retirements in Honolulu, Maui, and Hawaii counties.

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[41] PUC. *Decision and Order No. 34696*. Docket 2014-0183. July 14, 2017.

[42] PUC. *Decision and Order No. 34696*. Docket 2014-0183. July 14, 2017. Page 4 (page 7 of pdf).

[43] PUC. *Decision and Order No. 34696*. Docket 2014-0183. July 14, 2017. Page 6 (page 9 of pdf).

[44]. PUC. *Order No. 33877*. Docket 2014-0183. August 16, 2016.

[45] PUC. *Decision and Order No. 33795. Docket 2015-0022*. July 15, 2016.

[46] About 326 MW of distributed generation PV. Source: HECO. *PSIP Update Report*. December 23, 2016. Book 1. page ES-3.

[47] HECO Companies. *PSIP Update Report*. December 23, 2016. Book 1. page ES-3.

[48] HECO Companies. PSIP Update Report. December 23, 2016. Book 1. page 6-11 to 6-21.

[49] HECO Companies. *PSIP Update Report*. December 23, 2016. Book 1. page ES-3.

[50] Hawaii Electric, Maui Electric, and Hawaii Electric Light. "Regulators accept HECO's plan to reach 100% renewable energy." July 17, 2017.

Figure 17. Planned new entry and retirements in Honolulu County (2017-2045)

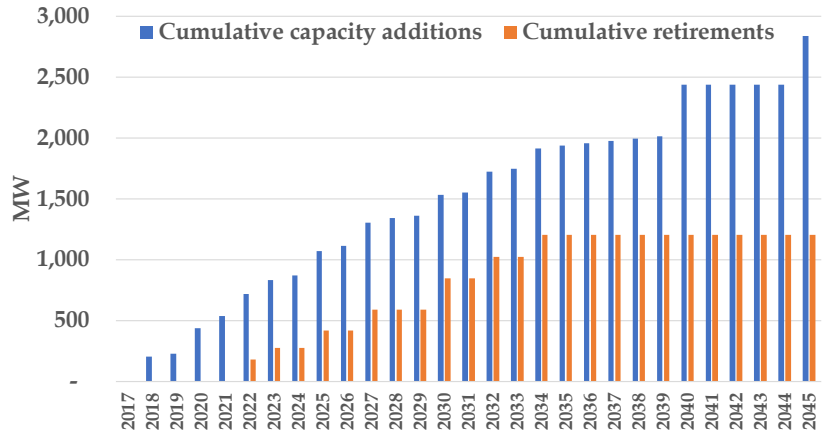


Figure 18. Planned new entry and retirements in Maui County (2017-2045)

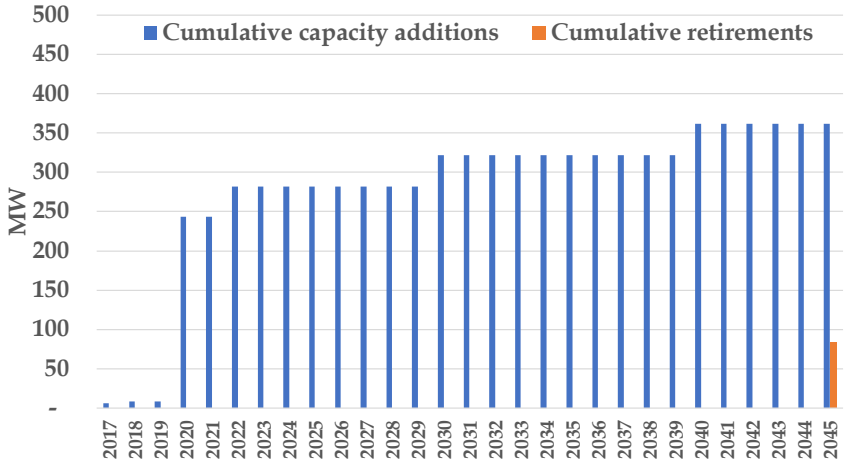
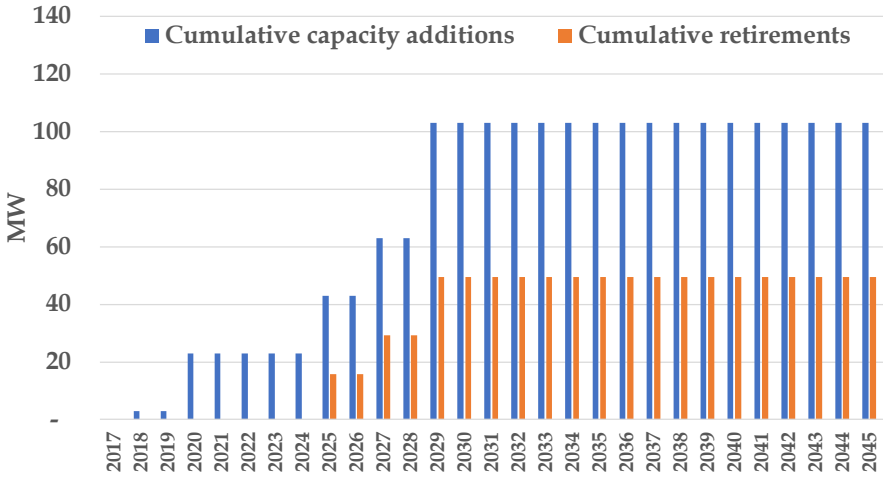


Figure 19. Planned new entry and retirements in Hawaii County (2017-2045)



Sources: HECO Companies, PSIP Update Report: December 2016, Book 1 (Chapters 4 and 6) and Book 2 (Appendix D).
Note: based on the Post-April PSIP long-term plan, assuming all remaining oil/diesel plants to be converted to biodiesel by 2045.

Combining information and data from PSIP's Chapter 6 (near-term plans) and Chapter 4 (production simulation analytical results with long-term plan options), as well as from HECO's regulatory filings, Figure 20 and Figure 21 collectively illustrate the resource mix evolution, away from oil and diesel generation, planned in the PSIP to achieve the goal of 100% renewable energy by 2045.

Specifically, between 2017 and 2021, the PSIP adds the following as shown in Figure 20):

- 49 MW of new oil/biomass-fueled generation, the Schofield Generating Station ("SGS") which the PUC has already approved;
- 157 MW of grid-scale wind;[51] and
- 686 MW of solar generation, including 360 MW grid-scale solar and 326 MW of distributed solar resources;[52]

as well as:

- 137 MWh of energy storage systems;
- 110 MW of demand response program resources; and
- 169 MVA of synchronous condensers.

Moreover, between 2021 and 2045, HECO Companies' long-term plans[53] include (Figure 20):

- retiring about 1,300 MW of currently existing coal, oil and diesel generation;
- converting nearly 800 MW of currently existing oil and diesel generation to biodiesel;
- adding about 900 MW of new biodiesel/biomass generation;
- adding about 820 MW of new wind resources, none grid-scale;
- adding about 580 MW of new solar resources, all grid-scale;
- adding about 10 MW of new hydro generation - pumped storage hydro ("PSH"); and
- adding about 40 MW of new geothermal generation;

as well as:

- adding about 380 MW of energy storage systems (including distributed, battery, and the 10 MW of new PSH); and
- another 70 MW of demand response program resources.

It is important to note that in its decision accepting the PSIP, the PUC highlighted that each electric utility's electric system has been becoming "more complex and operationally challenging as greater quantities of diverse renewable energy resources are integrated with older, relatively

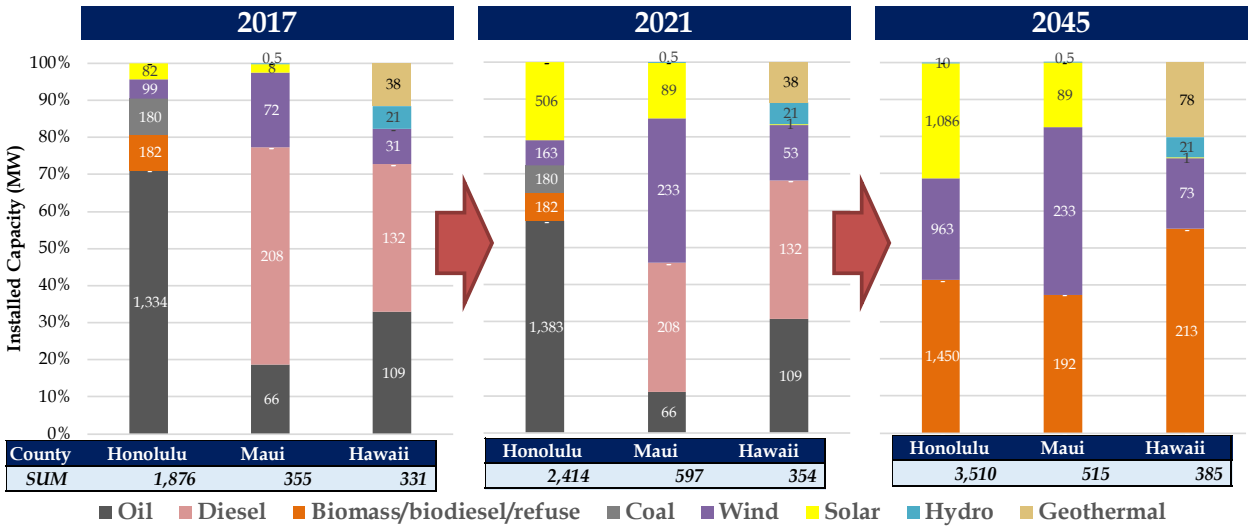
[51] HECO Companies. *PSIP Update Report*. December 23, 2016. Book 1. page 6-11 to 6-21.

[52] HECO Companies. PSIP Update Report. December 23, 2016. Book 1. page ES-3.

[53] PSIP presented multiple long-term plans, which will be discussed in deliverables for Task 1.1.5. The numbers here are based on the "Post-April PSIP Plan". Source: HECO. PSIP Update Report. December 23, 2016. Book 1. Page 4-7.

inflexible base load fossil-fuel generation resources" and "in large part because of continuing developments in DER [distributed energy resources], such as rooftop PV [photovoltaic]."[54]

Figure 20. PSIP-planned generation fuel mix evolution to achieve 100% RPS by 2045



Sources: HECO Companies, PSIP Update Report: December 2016, Book 1 (Chapters 4 and 6) and Book 2 (Appendix D); HECO-913. DOCKET NO. 2016-0328. PAGE 1 of 1. Table "Hawaiian Electric Company, Inc. 2017 TEST YEAR. Age of Generating Units – as of: 2017."
Note: based on the Post-April PSIP long-term plan, assuming all remaining oil/diesel plants to be converted to biodiesel by 2045.

Figure 21. PSIP-planned distributed generation, storage, and demand response programs to achieve 100% RPS by 2045

	2017				2021				2045			
County	Honolulu	Maui	Hawaii	TOTAL	Honolulu	Maui	Hawaii	TOTAL	Honolulu	Maui	Hawaii	TOTAL
Distributed Solar (MW)	479	119	103	701	734	159	134	1,027	734	159	134	1,027
Storage (MW)	-	-	-	-	70	11	56	137	380	81	56	517
Demand Response (MW)	-	-	-	-	89	11	11	110	89	81	11	180
Synchronous condensers (MVA)	-	-	-	-	129	15	25	169	129	15	25	169

Sources: HECO Companies, PSIP Update Report: December 2016, Book 1 (Executive Summary, Chapters 4 and 6) and Book 2 (Appendix D).

5.2.2 Summary of KIUC Strategic Plan Update 2016-2030

As mentioned earlier, the existing installed capacity in Kauai is 208 MW, with about 40% of electricity generated by renewable resources (biomass, solar, wind, and hydro). By 2023, KIUC targets to reach at least 50% of Kauai's power from renewable generation.[55] To achieve this goal, KIUC already has over 100 MW of proposed renewable energy planned, slated to come online by 2025, as listed in Figure 22.

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[54] PUC. *Decision and Order No. 34696*. Docket 2014-0183. July 14, 2017. Page 23 (page 26 of pdf).

[55] KIUC. *2015 Annual Report.* <http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/annualreport/AnnualReport2015.pdf>

Between 2017 and 2019, KIUC plans projects (battery energy storage systems ("BESS") repowering, hydro plant penstock replacement, gas turbine modifications, and installation of a synchronous condenser) to support the integration of renewables and the resilience of the grid. In terms of capital expenditures, these large KIUC's projects (each exceeding $1 million) are expected to collectively cost nearly $13 million.[56]

Recently, there are some projects that came online or are planned to be constructed. For instance, Solar City and Tesla completed the construction of Hawaii's largest utility-scale solar project in March 2017.[57] The project consists of a 52 MW-hour Tesla Powerpack 2 battery system installation and a 13 MW solar farm built by Solar City, and is expected to reduce Kauai's annual use of fossil fuels by 1.6 million gallons. KIUC has entered a 20-year contract with Tesla in which it has agreed to purchase power from Tesla at a rate of 13.9 cents per kWh. In regard to the project, President and CEO of KIUC noted, "The importance of this project for the member-owners of KIUC can't be overstated. By using solar energy stored in the battery after the sun goes down, we will reduce our use of imported fuels and our greenhouse gas emissions significantly."[58]

Furthermore, the PUC approved, on July 28, 2017, the KIUC deal with AES Corp for the construction of a solar and battery storage project which includes a 28 MW solar array paired with a 20 MW, 200 MWh battery system. KIUC is expected to pay 11 cents per kWh for power delivered from the project.[59] This will be the second solar-plus-storage project for KIUC and is expected to meet 11% of Kauai's energy needs.

Figure 22. KIUC planned renewable energy projects

Plant Name	Fuel type	Capacity (MW)	Proposed Online Date
AES Lawai	Solar	28	2018
Gay & Robinson, Olokele	Hydro	6	2019
Pacific Missile Range Facility	Solar plus Storage	44	2020
Pu'u Opae Pumped Storage	Hydro pumped storage	25	2023
	SUM	***103***	

Source: KIUC. "Renewable Energy Projects." Webpage, last accessed July 21, 2017. <http://website.kiuc.coop/content/renewable-energy-projects>; SNL Financial; and third-party commercial database

[56] KIUC. *2017 Capital Improvements Program for Ensuing Five Years*. December 27, 2016.

[57] "Tesla built a huge solar energy plant on the island of Kauai." *The Verge*. March 8, 2017.

[58] "Tesla unleashes major solar farm, battery storage project in Hawaii." *Pacific Business News.* Web. 8 March 2017. <https://www.bizjournals.com/pacific/news/2017/03/08/tesla-unleashes-major-solar-farm-battery-storage.html>

[59] "Hawaii co-op signs deal for solar+storage project at 11cents/kWh." Utility Dive. Web. 10 January 2017. <http://www.utilitydive.com/news/hawaii-co-op-signs-deal-for-solarstorage-project-at-11kwh/433744/>

5.3 Achieving the 100% clean energy target by 2045

HECO Companies and KIUC are ahead of their renewable energy goals and will both be able to achieve the clean energy target before 2045 based on their near-term and long-term plans.

Having achieved 23.2% of load in 2015 being served by renewable generation, HECO Companies exceeded the state's 2015 Renewable Portfolio Standards ("RPS") target of 15%.[60] Generally, HEI utilities expect to achieve the future RPS targets ahead of schedule as well (Figure 24), meeting the 100% renewable energy target by 2040, five years earlier than mandated by the state's RPS rules.[61]

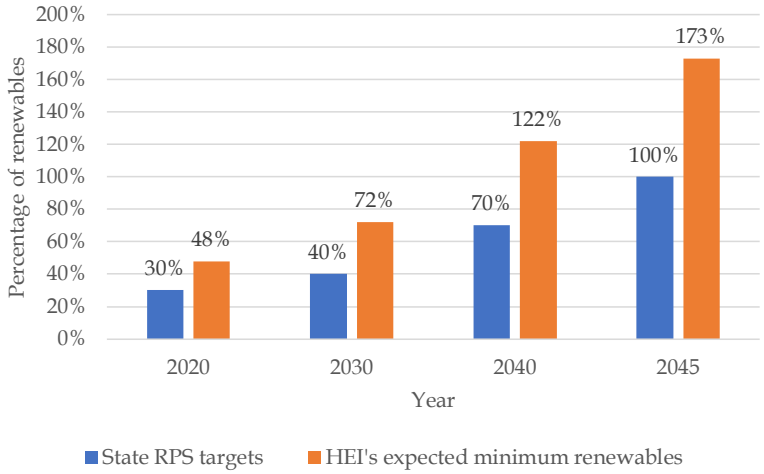
As reported in the PSIP, HECO Companies expect to reach the next mandate of "30% RPS by 2020" by 2018, two years early (Figure 25). By 2021, the forecast RPS are shown in Figure 23.

Figure 23. Forecasted RPS and renewables (MW) by 2021

Island and County	Forecast RPS (%)	Forecasted Renewables (MW)
Molokai Island (Maui County)	142%	8.50
Hawaii Island (Hawaii County)	80%	235.30
Maui Island (Maui County)	63%	284.00
Lanai Island (Maui County)	59%	6.70
Oahu Island (Honolulu County)	45%	1,299.00

Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 1, pages 6-11 to 6-21.

Figure 24. State of Hawaii's RPS mandates and HECO's anticipated target achievement

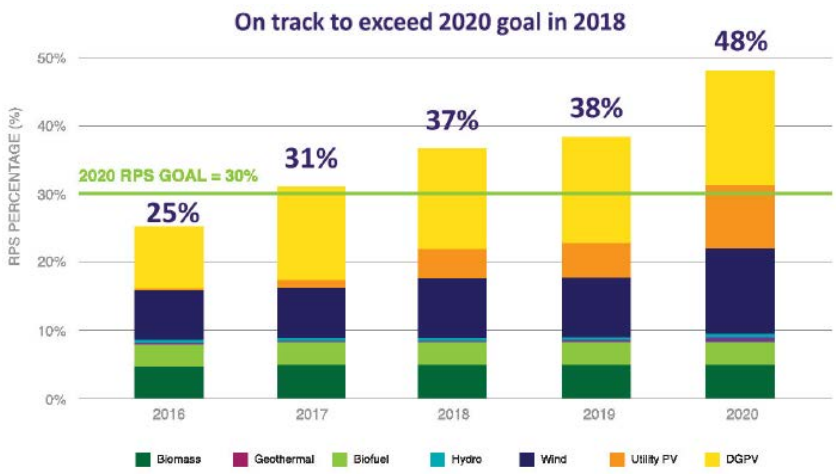


Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 1, page ES-1.

[60] Hawaiian Electric Company. "Record highs for renewable energy use in 2015." April 2016.

[61] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 1, page ES-1.

Figure 25. Hawaii utilities to exceed 2020 RPS goal of 30% by 2018



Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 1, page ES-9.

There are costs related to achieving the 100% clean energy target. HECO Companies' near-term action plans project the rates would increase substantially: between 18% and 25% during 2017-2021, and by 23% and 44% during 2017-2026.[62] As various observers have noted during the PSIP stakeholder process, this suggests that HECO have not approached the PSIP as a constrained optimization problem in which rates must be restrained.

HECO Companies estimate that, under various long-term plans:

- the total capital expenditures (in nominal dollar values) for 2017-2021 ranges from $3.2 billion to $3.5 billion, and for 2017-2045 from $15 billion to $21 billion as shown in ;
- the revenue requirement (net present value, 2017-2045) ranges from $35 billion to $37 billion (); and
- the costs to achieve the 100% renewable energy target ranges from about $37 billion to about $41 billion.[63]

In its decision approving the PSIP and while commending the Companies' commitment to achieving the Hawaii State RPS goals ahead of schedule, the PUC expressed concern regarding "technical feasibility and economics of the long-term resource plan for each island" because in determining which resources to add in the plans:

- the analysis did not consider all alternative technology options;
- the plan lacked an affordability assessment of the rate and bill impacts; and

[62] PUC. *Decision and Order No. 34696*. Docket 2014-0183. July 14, 2017. Page 33 (page 36 of pdf).

[63] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 1. Chapter 5.

- there were implications of potential negative impacts on reliability in the long term.

Figure 26. Estimated short- and long-term capital expenditures, by HECO Companies, by plan

Capital expenditures (nominal, 2017-2021, $b)		HECO	MECO	HELCO	TOTAL
Post-April PSIP Plan		$1.72	$1.19	$0.47	$3.38
E3 Plan		$1.62	$1.14	$0.42	$3.17
E3 Plan with LNG		$1.84	$1.22	$0.47	$3.53
E3 Plan with Generation Modernization		$1.70	-	-	-
E3 Plan with LNG and Generation Modernization		$1.93	-	-	-
	Min	***$1.62***	***$1.14***	***$0.42***	***$3.17***
	Max	***$1.93***	***$1.22***	***$0.47***	***$3.53***
Capital expenditures (nominal, 2017-2045, $b)		**HECO**	**MECO**	**HELCO**	**TOTAL**
Post-April PSIP Plan		$9.41	$3.30	$2.15	$14.86
E3 Plan		$13.92	$3.66	$2.55	$20.13
E3 Plan with LNG		$14.05	$3.92	$2.57	$20.54
E3 Plan with Generation Modernization		$13.93	-	-	-
E3 Plan with LNG and Generation Modernization		$13.72	-	-	-
	Min	***$9.41***	***$3.30***	***$2.15***	***$14.86***
	Max	***$14.05***	***$3.92***	***$2.57***	***$20.54***

Source: HECO Companies, PSIP Update Report, December 23, 2016, Book 1, Chapter 5.

Figure 27. Estimated revenue requirement (NPV, 2017-2045), by HECO Companies, by plan

Revenue Requirement (NPV, 2017-2045, $b)		HECO	MECO	HELCO	TOTAL
Post-April PSIP Plan		$26.53	$5.29	$5.04	$36.85
E3 Plan		$26.29	$5.05	$4.74	$36.09
E3 Plan with LNG		$24.94	$4.98	$4.84	$34.76
E3 Plan with Generation Modernization		$26.56	-	-	-
E3 Plan with LNG and Generation Modernization		$25.74	-	-	-
	Min	*$24.94*	*$4.98*	*$4.74*	*$34.76*
	Max	*$26.56*	*$5.29*	*$5.04*	*$36.85*

Source: HECO Companies, PSIP Update Report, December 23, 2016, Book 1, Chapter 5.

The PUC stated that they expect future planning to "more fully address the capital costs, operating costs, and reliability concerns associated with long-term achievement of the RPS goals."[64] The PUC also discussed other concerns about the PSIP (discussed in more details in Section 5.5), and outlined topics requiring further analysis. In addition, the PUC also outlined high-priorities for near-term actions by HECO Companies :[65]

1. competitive procurement of grid-scale renewable resources;
2. Community-Based Renewable Energy ("CBRE") and DER integration; and
3. system-level grid reliability improvement projects.

[64] PUC. *Decision approving PSIP*. July 14th, 2017. Page 41-42 (page 44-45 of pdf).

[65] PUC. *Decision and Order No. 34696*. Docket 2014-0183. July 14, 2017. Page 30 (page 33 of pdf).

Furthermore, the PUC acknowledged "the challenges inherent in long-term forecasting and analysis, particularly where, as here, the underlying inputs and assumptions are dynamic and subject to significant uncertainty over the next decade or more,"[66] stating that they encourage flexibility and expect future plans to change. Additionally, having accepted the PSIP, the PUC clarified that it does not mean pre-approval of any specific resource or action identified in the PSIP, as HECO Companies would still be responsible to prove the merits and prudency for each resource or action in pertinent proceedings, with transparency, comprehensive operation and financial analyses, and stakeholder engagement.

As for KIUC, it aims to generate at least 70% of electricity by using "cost effective renewable resources" by 2030 based on its Strategic Plan Update 2016-2030. This new goal will enable KIUC to achieve the 100% renewable energy goal by 2035, 10 years ahead of the state RPS mandate. While moving forward to achieve the renewable energy goal, KIUC plans to maintain system reliability and price stability. For instance, according to KIUC's strategic plan, any new renewable generation source that is added should be no more than 20% of Kauai's electric usage in any single year. Fixed pricing is used for both fossil fuel requirements and recent renewable projects to stabilize electric rates.[67]

5.4 Assessment of potential transmission investments

As part of a discussion about a comprehensive grid transformation, HECO Companies in the PSIP stated that elements of the Hawaii transmission system will need to be upgraded and expanded, notably to:

- accommodate load growth and generation retirements on Maui before 2024; [68]
- accommodate large amounts of variable renewable generation on Oahu over 10 to 15 years;[69] and
- address aging infrastructure and reliability issues on Hawaii Island. [70]

In addition to eliminating usage of LNG imports, the PSIP update from December 2016 also no longer includes the interisland transmission project (though HECO Companies stated that both options will continue to be evaluated as long-term alternatives to achieve 100% renewable energy). According to PSIP, there is "extreme uncertainly around the cable permitting, feasibility, and timing."[71] The PSIP analysis also determined that the interisland transmission scenario created an unrealistic result, where renewable energy additions on

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[66] PUC. *Decision approving PSIP*. July 14th, 2017. Page 24 (page 27 of pdf).

[67] KIUC. *Strategic Plan Update 2016-2030*. January 31, 2017 (Adopted).

[68] HECO. *PSIP Update Report.* December 23, 2016. Book 1, page 7-22.

[69] HECO. *PSIP Update Report.* December 23, 2016. Book 1, page I-6.

[70] HECO. *PSIP Update Report.* December 23, 2016. Book 1, page 7-29.

[71] HECO. *PSIP Update Report.* December 23, 2016. Book 1, page 7-9.

neighboring islands had to be substantially increased in a short period of time, while renewable additions on Oahu Island would have to decrease substantially. Therefore, the PSIP Update of December 2016 does not assume availability of the interisland transmission cables. In July 2013, the PUC started Docket No. 2013-0169 to examine whether the Oahu-Maui Grid Tie may be in public interest, and the proceeding is still awaiting determination from PUC.[72] According to the PSIP, "E3 estimated that the benefits a large cable system interconnecting each island could have benefits as large as $3 billion not including the cost of cable.[73]

As for KIUC, several transmission projects are planned on the Kauai Island, which collectively are estimated to cost nearly $37 million:[74]

- Northshore Transmission Line & Seabird Mitigation (2019-2020);
- Repair T&D Warehouse (2018-2019);
- Construction of Aepo Substation (2009-2019); and
- Wailua Corridor widening (2017).

5.5 Analysis of key assumptions and how changes would impact investment

Over the course of the stakeholder process to review and ultimately approve the PSIP,[75] a number of concerns have been raised by DBEDT, PUC Staff, and other stakeholders, which in turn are echoed in PUC's final decision. Notably,

- the PUC was particularly concerned about increases in rates: according to PUC, "[t]he Companies do not appear to have evaluated the capital investments, financial commitments, and the resulting increasing rates, in the context of **affordability to customers** and the risk of stranded assets;"[76]
- certain assumptions were "forced" into the models, and this may have disproportionately favored utility-owned resources;

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[72] Hawaii State Energy Office. "Hawaii Energy Facts & Figures." November 2016. Page 4.

[73] HECO Companies. *PSIP Update Report*. December 23, 2016. Book 1, page 7-9.

[74] KIUC. *2017 Capital Improvements Program for Ensuing Five Years*. December 27, 2016.

[75] When the PUC directed the Companies to prepare the PSIP, the intended purpose of the proceeding was: "to determine a reasonable power supply plan for each of the HEI that can serve as a strategic basis and provide context to inform important pending and future resource acquisitions and system operation decisions." The PUC found that the updated PSIP was a significant improvement over the previous PSIPs as the Companies "expanded the scope of their analysis, and engaged new planning tools to better address the substantial planning challenges they face," "made their filings more transparent, incorporated additional stakeholder input, and addressed many of the Commission's previously stated concerns." The PUC described the updated PSIP as "a set of plans that provides useful context for making informed decisions regarding the near-term path forward." Source: PUC. *Decision and Order No. 34696*. Docket 2014-0183. July 14, 2017. Page 24-25 (page 27-28 of pdf).

[76] PUC. *Decision approving PSIP*. July 14th, 2017. Page 35 (page 38 of pdf).

- the PSIP lacked sufficient analysis of alternative options for certain projects (proposed conventional generation plants, utility-owned BESS, or other transmission assets).
- this in turn influences the mix and schedule of renewables that the optimization analyses produce, and may not yield the most optimal solution in terms of the fuel mix, timing, sizing, and costs;

- wind generation modeling methodology may have created an artificial transmission constraint in system modeling, leading to sub-optimal results in terms of wind generation planning; [77]
- HECO Companies proposed procurement approach and methodology lack supporting analysis and explanation to demonstrate that the metrics and criteria used to compare proposals will be consistent with the PSIP and state energy policies;
  - all new resources should be procured in an "agnostic" manner, considering all alternatives (for example, including non-transmission alternatives ("NTAs") for a transmission line; or other types of storage (e.g., PSH) for a proposed BESS; and considering other generation, storage, DER, DR, and energy efficiency options); and
- inconsistencies in the methodology to determine project useful lives, which could have led to uneven comparison between competing technologies.[78]

Several parties and PUC generally agreed that future planning processes need to be periodically updated and revisited to continually improve the plans, and therefore recommended and encourages flexibility and medications to future plans. The PUC directed the Companies to file a report on March 1, 2018, detailing the approach and schedule for the next round of resource planning.

[77] PUC. *Decision approving PSIP*. July 14th, 2017. Page 19-20 (page 22-23 of pdf).

[78] Project lives sampled by LEI were in many cases shorter than those for which LEI has seen PPAs issued in other jurisdictions.

6 Appendix A: Scope of work to which this deliverable responds

Task 1.1.1 Introduction of Ownership Models and asset identification; kick-off meeting

CONTRACTOR shall provide a brief narrative introduction of each ownership model and provide a discussion on the potential advantages and disadvantages of ownership of generation, transmission, and distribution facilities needed to provide service from both operational/technical and economic perspectives. This introduction shall provide a high-level needs assessment for infrastructure development through 2045 and provide an estimate of the kinds of facilities that need to be developed at specific points in time. The narrative shall also include transmission investments leveraging the existing asset base as much as possible. CONTRACTOR shall hold kick-off and initial stakeholder meetings (utility, consumer groups, renewable industry) to discuss the needs assessment and high-level plans to achieve the 2045 State target.

DELIVERABLE FOR TASK 1.1.1. CONTRACTOR shall provide its conclusions and all work to provide an assessment of ownership models, providing a discussion of how they work, their advantages and disadvantages from both an operational/technical perspective and an economic perspective, as well as a technical assessment of the existing power sector assets in Hawaii and the needed investments through 2045 to enable the State to achieve its 100% clean energy target. CONTRACTOR shall also provide the conclusions of the kick-off and initial stakeholder meetings in a report in MS Word, with MS Excel, Power Point, and other written documentation. CONTRACTOR shall submit deliverable for TASK 1.1.1 to the STATE for approval.

Task 1.2.1 Comparison of ownership models and how they relate to the State's key factors

CONTRACTOR shall provide a comparison of the ownership models: 1) how they are similar to and/or differ; 2) the relative advantages and disadvantages of each; 3) the steps required for their formation; and 4) their relative availability to provide electric service. CONTRACTOR shall evaluate each model's ability to: (a) achieve State energy goals; (b) maximize consumer cost savings; (c) enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs; (d) eliminate or reduce conflicts of interest in energy resource planning, delivery and regulation; and (e) align management, ownership and ratepayer interests.

DELIVERABLE FOR TASK 1.2.1. CONTRACTOR shall provide its conclusions and all work for a detailed comparison of ownership models, specifically how they relate to the State's key factors (listed herein). This assessment shall be qualitative and include a scoring concept (i.e., strongly favorable, neutral, or strongly negative) that is intuitive and easy to grasp for presentation purposes. CONTRACTOR shall articulate and summarize points with a table comparing models, with a written narrative in MS Word and summary in PowerPoint. CONTRACTOR shall submit deliverable for TASK 1.2.1 to the STATE for approval.

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Hawaii maps for service areas of each county

prepared for Hawaii Department of Business, Economic Development, & Tourism by London Economics International LLC and Meister Consultants Group

July 26th, 2017

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business, Economic Development, and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals; this document is one of several working papers associated with that engagement. This memo provides the maps[1] for service areas of each county in Hawaii. Each map delineates the generation, transmission, and substation facilities necessary to provide electric services.[2]

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[1] Maps of each county were generated from Velocity Suite using its mapping application. Maps of potential energy resources were generated by using SNL Global Market Intelligence mapping application. The data is mostly from Hawaiian Electric Companies and Kauai Island Utility Cooperative.

[2] Distribution system facilities are not included in the maps. LEI only has a list of the distribution system facilities that are owned by the utilities. LEI has contacted Hawaiian Electric Industries Inc. ("HEI") and they confirmed that there are no publicly available maps of their distribution system network and this information is confidential.

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List of acronyms

AFR	Annual Financial Reports for Electric Utilities
DBEDT	Hawaii Department of Business, Economic Development, and Tourism
EIA	US Energy Information Administration
HECO	Hawaiian Electric Company
HEI	Hawaiian Electric Industries Inc.
HELCO	Hawaii Electric Light Company
KIUC	Kauai Island Utility Cooperative
kV	Kilovolt
LEI	London Economics International LLC
LNG	Liquefied natural gas
MECO	Maui Electric Company
MVA	Mega-volt ampere
MW	Megawatt
PSIP	Power System Improvement Plan

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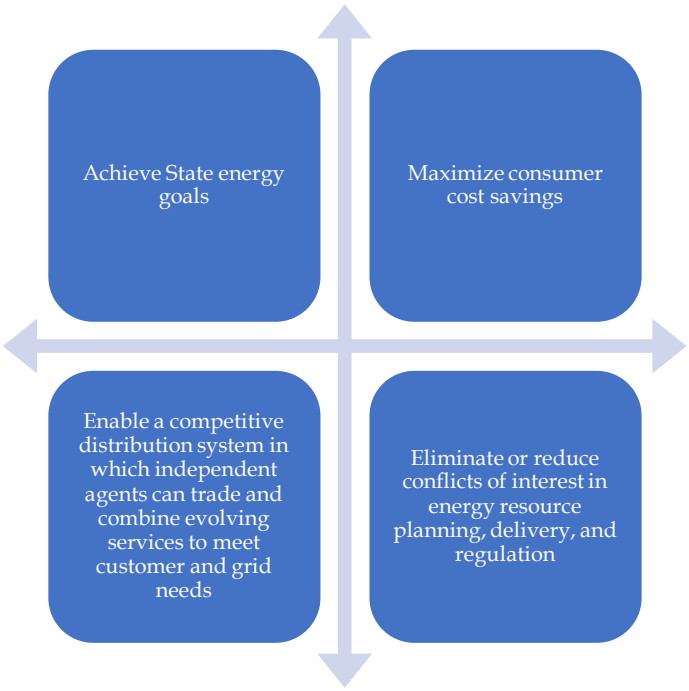
1 Introduction and scope

1.1 Project description

The Hawaii Department of Business, Economic Development, and Tourism ("DBEDT") was directed by the Hawaii State Legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[3] was contracted to perform this study.[4]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[5] listed in Figure 1.

Figure 1. State's key criteria



Source: Scope of Services under Contract No. 65595

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and

[3] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[4] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[5] House Bill No. 1700 Relating to the State Budget.

regulatory models and determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[6]

1.2 Role of this deliverable relative to others in the project

This deliverable is responsive to Task 1.1.2 in the project scope of work. It provides a map of the service area for each county. This map delineates the generation, transmission, substation, and distribution system facilities necessary to provide services, per our scope of work. It should be noted that sources used to create these maps are based on publicly available information. Therefore, we do not include information that is confidential or not available to the public.

In addition, various aspects of the generation, transmission, substation, and distribution systems in the State will be further explored in subsequent deliverables. This includes:

- assessment of existing generation, transmission and distribution infrastructure in each county (Task 1.1.3); and

- assessment of future needs for generation, transmission and distribution infrastructure in each county (Task 1.1.4).

1.3 Future refinements

This deliverable is subject to further refinement and change as the project moves forward and as we receive more information from the utilities on their assets.

[6] Hawaii Contract No. 65595. Scope of Services.

2 Introduction

The state of Hawaii has five counties, including Hawaii, Maui, the City and County of Honolulu, Kauai, and Kalawao. Since Kalawao County is a judicial district of Maui County and it has limited electricity system facilities, this memo shows its electric infrastructure in the section of Maui County.

Figure 2. The state of Hawaii generation and transmission system facilities



Source: Created the map using the Energy Velocity Suite

Hawaii has a total capacity of 3,427 MW as of September 2017.[7] About 46% of the net capacity is served by oil, 11% served by diesel, 5% served by coal, and the rest (38%) are served by solar, wind, etc. According to US Energy Information Administration ("EIA"), Hawaii is the most petroleum dependent state in the United States.[8] Meanwhile, renewable energy has been increasing as Hawaii sets a legal target to mandate that 100% of the state's net electricity sales

[7] Analysis of generation system is based on data from Hawaiian Electric Companies' 2016 Power Supply Improvement Plan ("PSIP"), SNL, KIUC website, KIUC 2017 Capital Improvements Program for Ensuing Five years, HECO Power Facts, and Power Purchase Contracts data from HEI.

[8] EIA. *State Profile and Energy Estimates – Hawaii*. Website. < https://www.eia.gov/state/analysis.php?sid=HI >. Access date: September 19, 2017.

comes from renewable sources by 2045. About 68% of this net capacity is located in the City and County of Honolulu, with the remainder located in Maui (14%), Hawaii (12%), and Kauai (6%) counties. Figure 2 shows the generation and transmission system facilities of the state.

As for the transmission and distribution system,[9] the electrical grid on each island is not connected to any other island. Hawaiian Electric Industries Inc. ("HEI") and Kauai Island Utility Cooperative ("KIUC") are the two primary electric utilities that service the power needs of the state. HEI and its subsidiaries, including Hawaiian Electric Company ("HECO"), Maui Electric Company ("MECO"), and Hawaii Electric Light Company ("HELCO"), serve the majority of the state's electric utility customers. KIUC serves the island of Kauai. [10]

3 Hawaii County

Hawaii County is home to Hawaii Island, also known as "the Big Island". The Big Island is the largest island in the state of Hawaii, with a total land area of 4,028 square miles. It has a population of 198,449 as of the 2016 estimation.[11]

The total net capacity of Hawaii County as of September 2017 is about 431 MW (including about 103 MW of DGPV as forecasted in PSIP[12]), 12% of which is from fuel oil, 14% from naphtha, and 31% from diesel. HELCO is the largest generation player in the county with about 44% share of capacity (or 186 MW). Hamakua Energy Partners LP was recently acquired by HEI subsidiary, Pacific Current[13], leaving Puna Geothermal Venture (34.6 MW), Pakini Nui Wind Farm (20.5 MW), and Hawi Wind Farm (10.5 MW) as the other major generation players in the county.

Hawaii County is served by HELCO. HELCO's total length of transmission line is about 622 miles. There are 75 substations (including transmission and distribution) in service and 14 substations proposed in the county. Figure 3 shows the map of the Hawaii County electric facilities. The generation, transmission, and substation facilities are explained in detail below.

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[9] Analysis of transmission system and substations is based on data from Velocity Suite and Annual Financial Reports ("AFR") for Electric Utilities 2016.

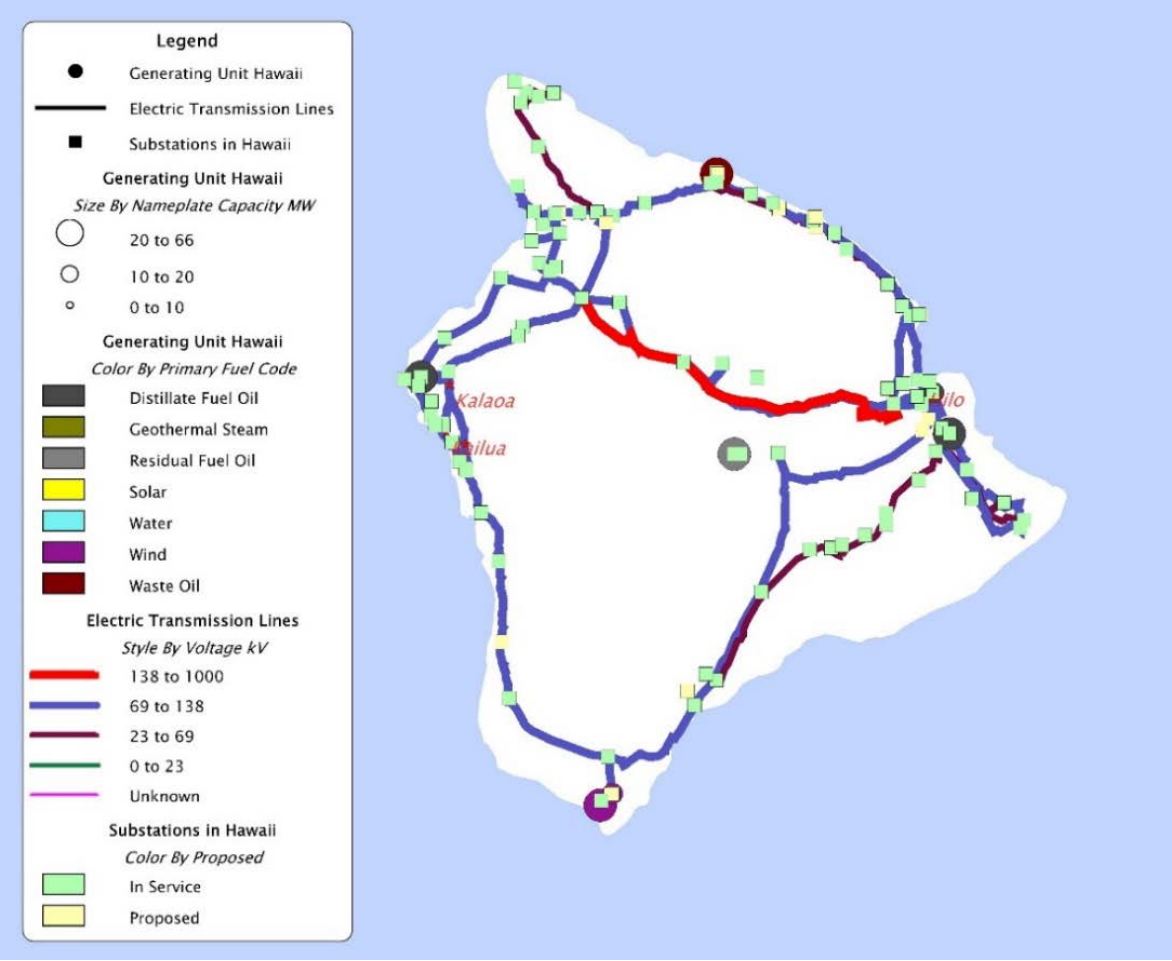
[10] Hawaii State Energy Office. *Hawaii Energy Facts & Figures*. Honolulu: May 2017.

[11] U.S. Census Bureau, Population Division.

[12] Hawaiian Electric, Maui Electric, and Hawaii Electric Light ("HECO Companies"). *PSIP Update Report*. Book 3, page J-64. December 23, 2016.

[13] "HEI subsidiary to acquire 60-MW oil-Fired plant from ArcLight." SNL, 21 Sept. 2017, www.snl.com/web/client?auth=inherit#news/article?KeyProductLinkType=2&id=42044678. Accessed 25 Sept. 2017.

Figure 3. Hawaii County electric facilities



Source: Created the map using the Energy Velocity Suite

3.1 Hawaii County generation facilities

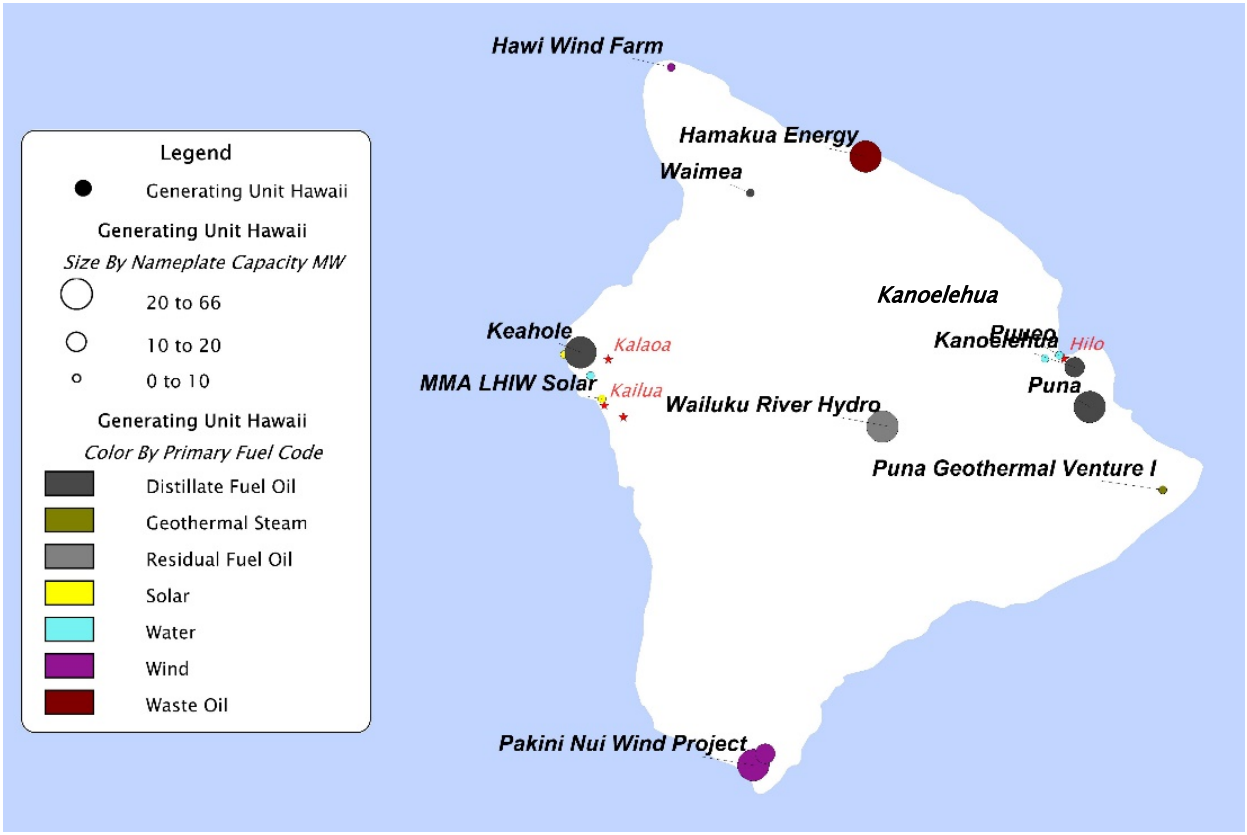
Oil, naphtha, and diesel are the dominant fuels in the Hawaii County as shown in Figure 4 below. They comprise 57% of the total net capacity. Other energy sources in use in the county include solar (24%), geothermal (8%), wind (7%), and hydro (4%). There are also proposed generating resources for the next few years, which include community based renewable energy (CBRE) projects (1 MW grid-scale PV, 2MW onshore wind), and a 20-MW onshore wind farm.[14] These are expected to be online in 2018 and 2020, respectively.[15] In addition to these resources, 21.5 MW

[14] Hawaiian Electric, Maui Electric, and Hawaii Electric Light ("HECO Companies"). *PSIP Update Report*. Book 1, page 6-20. December 23, 2016

[15] Hawaiian Electric, Maui Electric, and Hawaii Electric Light ("HECO Companies"). *PSIP Update Report*. Book 1, page 6-20. December 23, 2016.

of biomass plant developed by Hu Honua Bioenergy, LLC is anticipated to be operational by the end of 2018.[16] And 30.3 MW of DGPV is forecasted to be installed in the county through 2021.

Figure 4. Hawaii County generation facilities



Source: Created the map using the Energy Velocity Suite

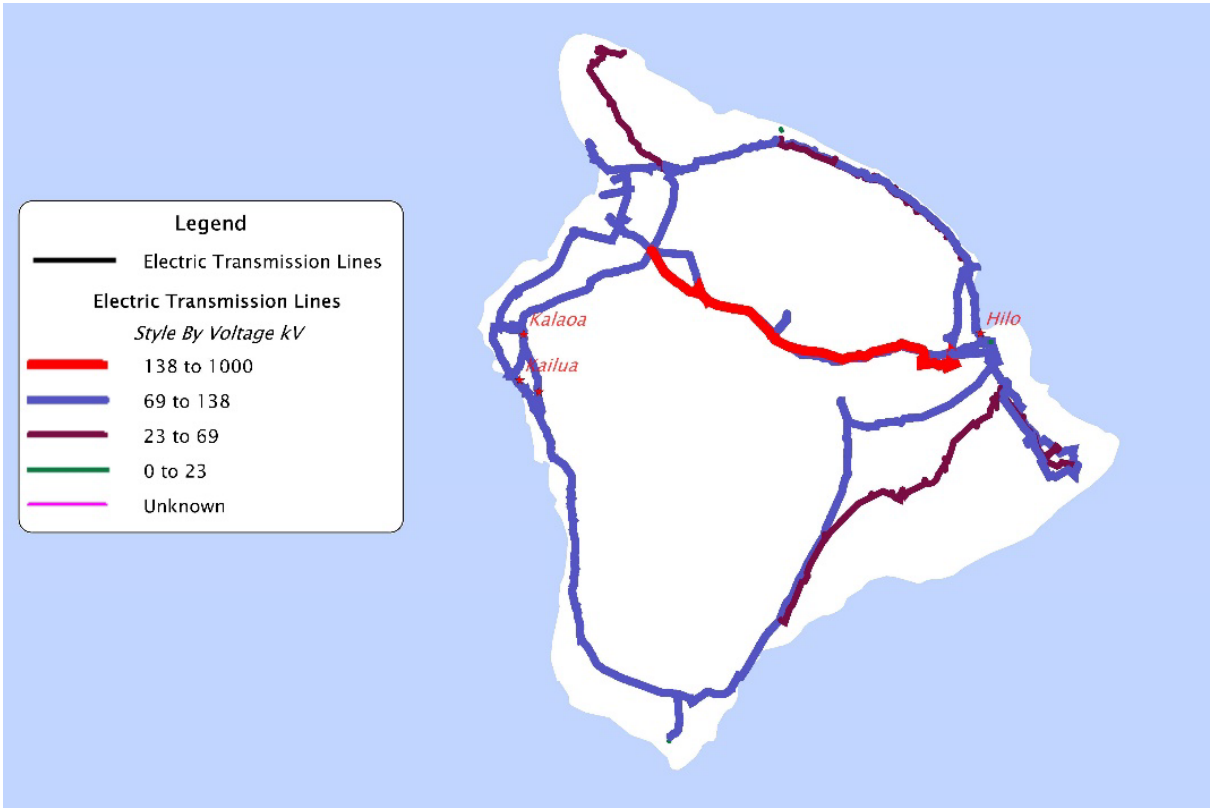
3.2 Hawaii County transmission facilities

All of the transmission facilities in Hawaii County are owned by HELCO. Relative to other transmission facilities in the US, the transmission facilities in the county have a lower voltage ranging between 13.8 and 138 kV. As of December 2016, there is one group of lines operating at 13.8 kV, one group of lines operating at 34.5 kV, and two groups of lines operating in 69 kV as shown in Figure 5. In addition, the total length of transmission lines is about 622 miles.[17]

[16] Hawaii State Energy Office. *Hawaii Renewable Energy Projects Directory*. Access Date: January 11, 2018. <http://energy.ehawaii.gov/epd/public/energy-project-details.html?rid=69-77d4f1ba859b5197>.

[17] Annual Financial Reports ("AFR") for Electric Utilities 2016.

Figure 5. Hawaii County transmission facilities



Source: Created the map using the Energy Velocity Suite

3.3 Hawaii County substation facilities[18]

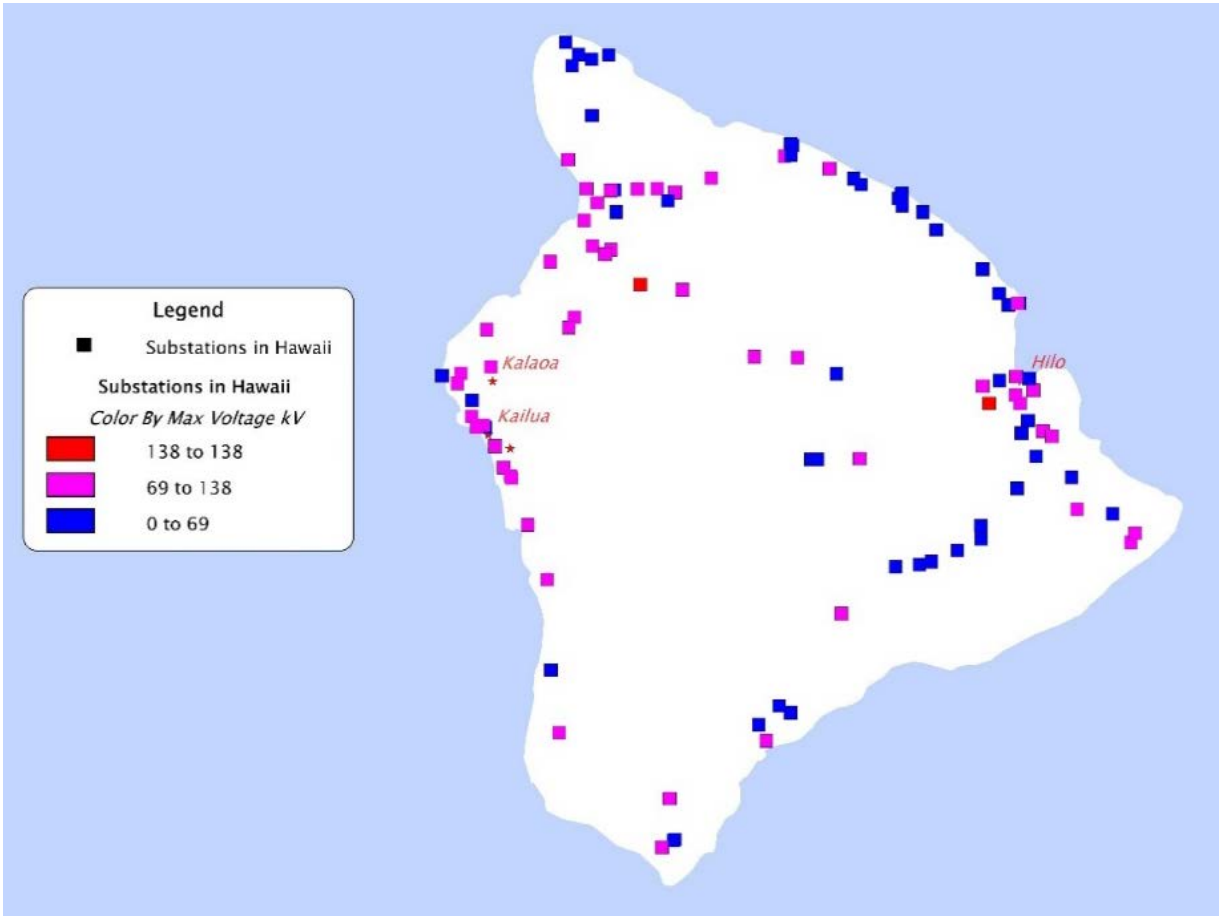
There are 74 substations in Hawaii County, including ten transmission substations, five transmission & distribution substations, and 59 distribution substations. As of December 2016, 87% of the substations have no more than 25 MVA capacity in service in the county. Substations with greater capacity in service include Keahole (a transmission substation, 131 MVA), Kanoelehua (a transmission & distribution substation, 125 MVA), and Puna (a transmission substation, 79 MVA).

When it comes to the capacity of the transformer, most of the transmission substations have a primary voltage of 69 MVA, except the Shipman substation which has a primary voltage of 13.8 MVA. The transmission & distribution substations have primary voltages ranging from 13.8 MVA to 69 MVA. As for distribution substations, 36 substations have a primary voltage of 69 MVA, and 22 substations have a primary voltage of 34.5 MVA. The only exception is Leilani distribution substation which has a primary voltage of 13.8 MVA.

[18] Number of substations, capacity in service, and capacity of transformer are based on Annual Financial Reports ("AFR") for Electric Utilities 2016. Operating voltage and map itself is based on Velocity Suite database.

As for the operating voltage, 69kV[19] is the predominant operating voltage of substations in the county as shown in Figure 6 below. Kaumana Switching Station and Keamuku Switching Station have a maximum voltage of 138 kV.

Figure 6. Hawaii County substation facilities



Source: Created the map using the Energy Velocity Suite

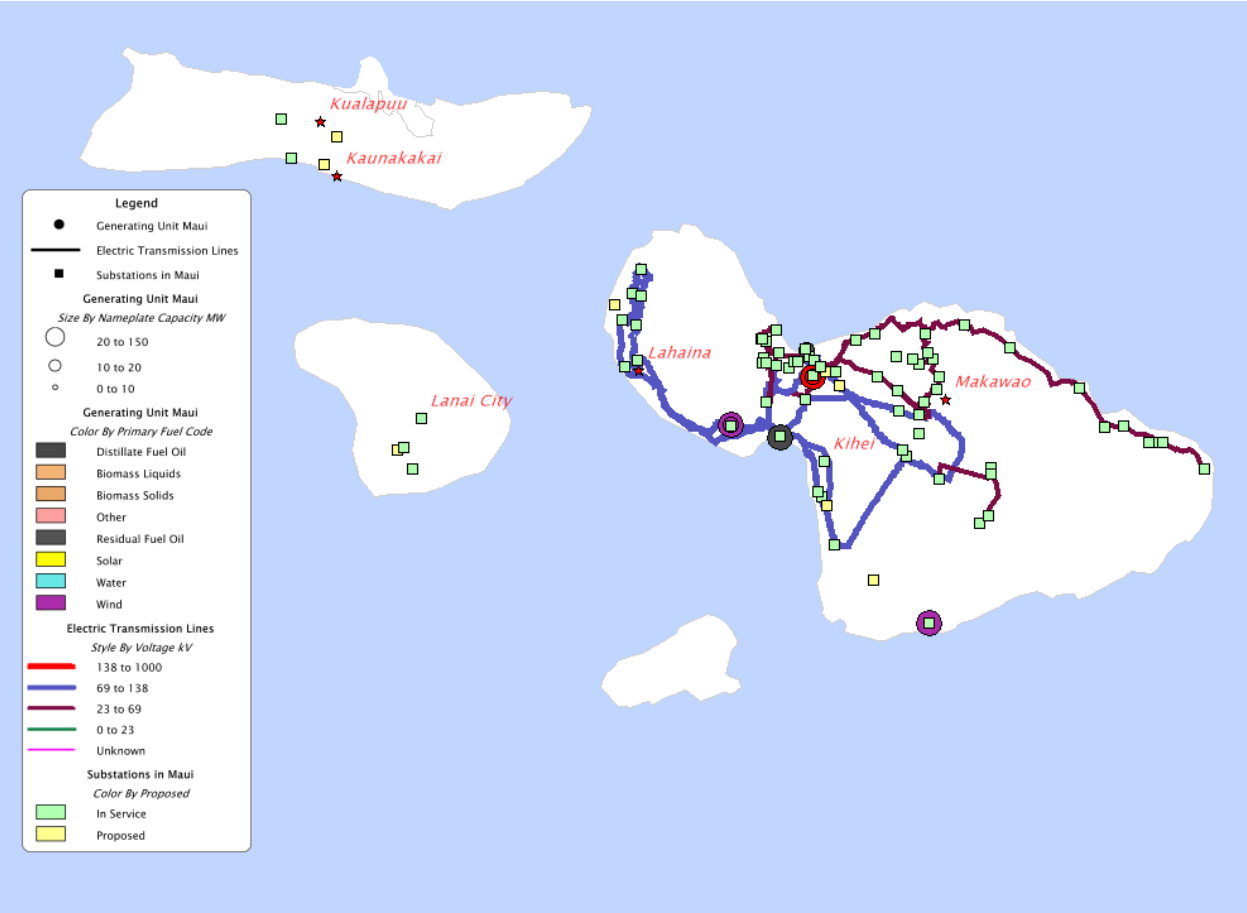
4 Maui County

Maui County consists of three currently populated islands, namely Maui, Lanai, and Molokai. It is relatively small compared to Hawaii County, with a total land area of 1,161 square miles. Maui County has a population of 165,474 as of the 2016 estimation.[20] A portion of Molokai comprises Kalawao County, but it is taken into consideration as part of Maui County in this section.

[19] The voltage, in kilovolts, of the largest feature from the Electric Transmission Lines that connects to the feature.

[20] U.S. Census Bureau, Population Division.

Figure 7. Maui County electric facilities



Source: Created the map using the Energy Velocity

Maui County's total net capacity as of September 2017 is about 466 MW including 119 MW of DG.[21] More than 51% of the county's net capacity is from diesel and 7% from fuel oil. MECO is the largest generation player with about 59% (or 274 MW) of the county's installed capacity.[22] MECO is also the only transmission and distribution owner in the county, and it owns transmission lines totaling about 258 miles. Figure 3 shows the map of the electric facilities in Maui County. The generation, transmission, and substation facilities are explained in detail below.

[21] Hawaiian Electric, Maui Electric, and Hawaii Electric Light ("HECO Companies"). *PSIP Update Report*. Book 3, page J-62/63. December 23, 2016. This DG capacity was 92 MW at the end of 2016 in PSIP Book 2, page D-24.

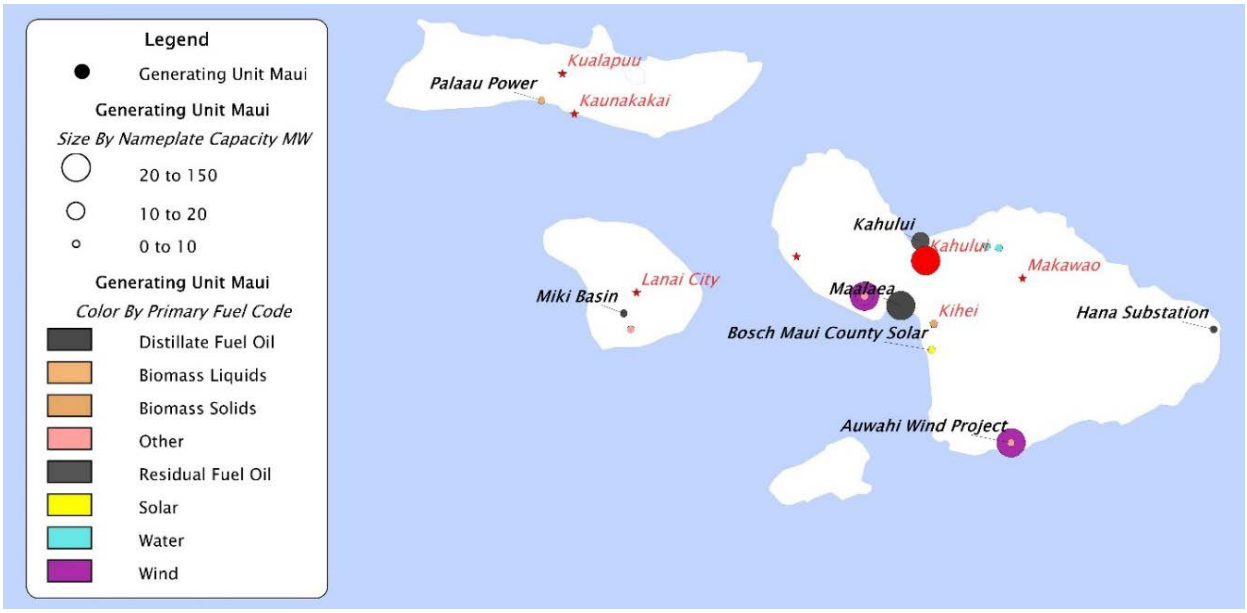
[22] Hawaiian Electric, Maui Electric, and Hawaii Electric Light ("HECO Companies"). *PSIP Update Report*. Book 2, page D-18 – D-24. December 23, 2016.

4.1 Maui County generation facilities

Similar to Hawaii County, Maui County's dominant fuels are diesel and fuel oil. They comprise nearly 59% (274 MW) of the total installed capacity in the county. Maui County also has solar (26%) and wind (15%) resources like Hawaii County.[23] There are also proposed generating resources in the county, which include 5.74MW grid-scale PV (2017), 1MW grid scale PV (2018,CBRE), 2MW onshore wind (2018,CBRE), and 60 MW of onshore wind (2020) on Maui island, 5 MW of grid-scale wind (2020) on Molokai, and 4 MW of grid-scale wind (2020) on Lanai.[24] In addition to these resources, 38.4 MW (Maui), 1.4 MW (Molokai), and 0.7 MW (Lanai) of DGPV are forecasted to be installed in the county through 2021.

As mentioned earlier, MECO owns the majority of the installed generation capacity. Other major generation players in Maui include Kaheawa Wind Power LLC, Terraform Power, NRG Energy, BP, and Sempra Energy, which all collectively own a combined capacity of 72 MW or 15% of the total capacity in the county.

Figure 8. Maui County generation facilities



Source: Created the map using the Energy Velocity Suite

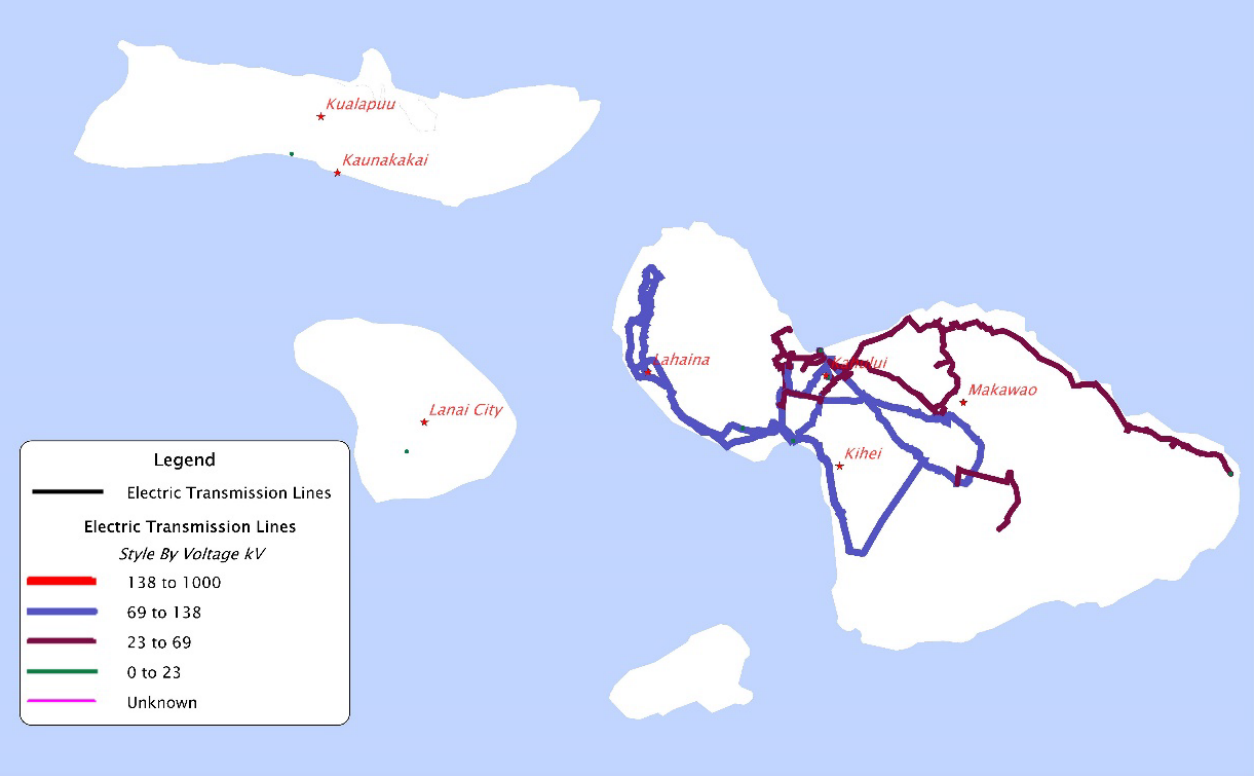
[23] Hawaiian Electric, Maui Electric, and Hawaii Electric Light ("HECO Companies"). *PSIP Update Report*. Book 2, page D-18 – D-24. December 23, 2016.

[24] Hawaiian Electric, Maui Electric, and Hawaii Electric Light ("HECO Companies"). *PSIP Update Report*. Book 1, page 6-13. December 23, 2016.

4.2 Maui County transmission facilities

Figure 9 shows the transmission facilities in Maui County. All the transmission facilities are owned by MECO. MECO has transmission facilities with voltages in 23 kV, 34.5 kV, and 69 kV. There are no 138 kV lines in Maui, unlike in Hawaii County. As of December 2016, there are two groups of lines operating at 23 kV, one group of lines operating at 34.5 kV, and three groups of lines operating at 69 kV. As of December 2016, the total length of transmission lines is about 258 miles.[25]

Figure 9. Maui County transmission facilities



Source: Created the map using the Energy Velocity Suite

4.3 Maui County substation facilities[26]

There are 89 substations in Maui County, which consist of 85 transmission substations and 65 distribution substations. Two-thirds (57) of the transmission substations have a primary voltage of 23 MVA, and nearly a third (25) of them have a primary voltage of 69 MVA. Only Palaau, Palaau-Spare 4.69 MVA, and Puunana transmission substations have a primary voltage of 34

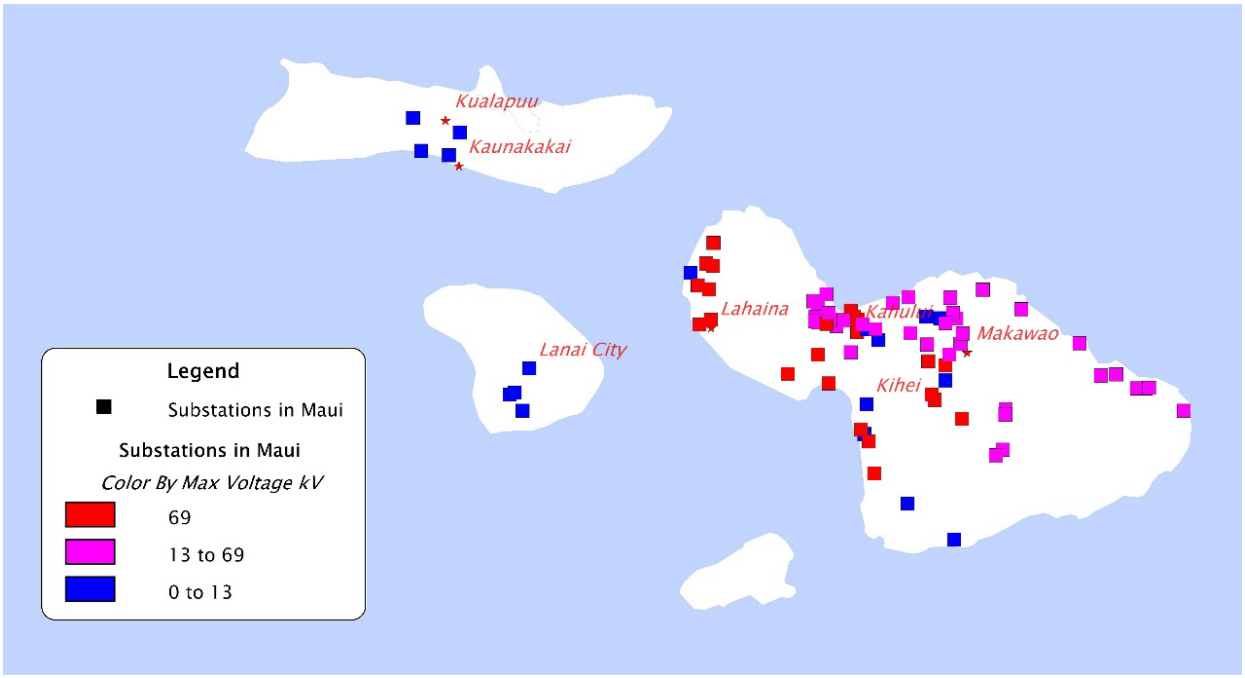
[25] Annual Financial Reports ("AFR") for Electric Utilities 2016.

[26] Number of substations, capacity in service, and capacity of transformer are based on Annual Financial Reports ("AFR") for Electric Utilities 2016. Operating voltage and map itself is based on Velocity Suite database.

MVA. As for distribution substations, all of the four distribution substations have a primary voltage of 12.47 MVA.

As for the operating voltage, 23 kV[27] is the predominant operating voltage of substations in the county as shown in Figure 10 below.

Figure 10. Maui County substation facilities



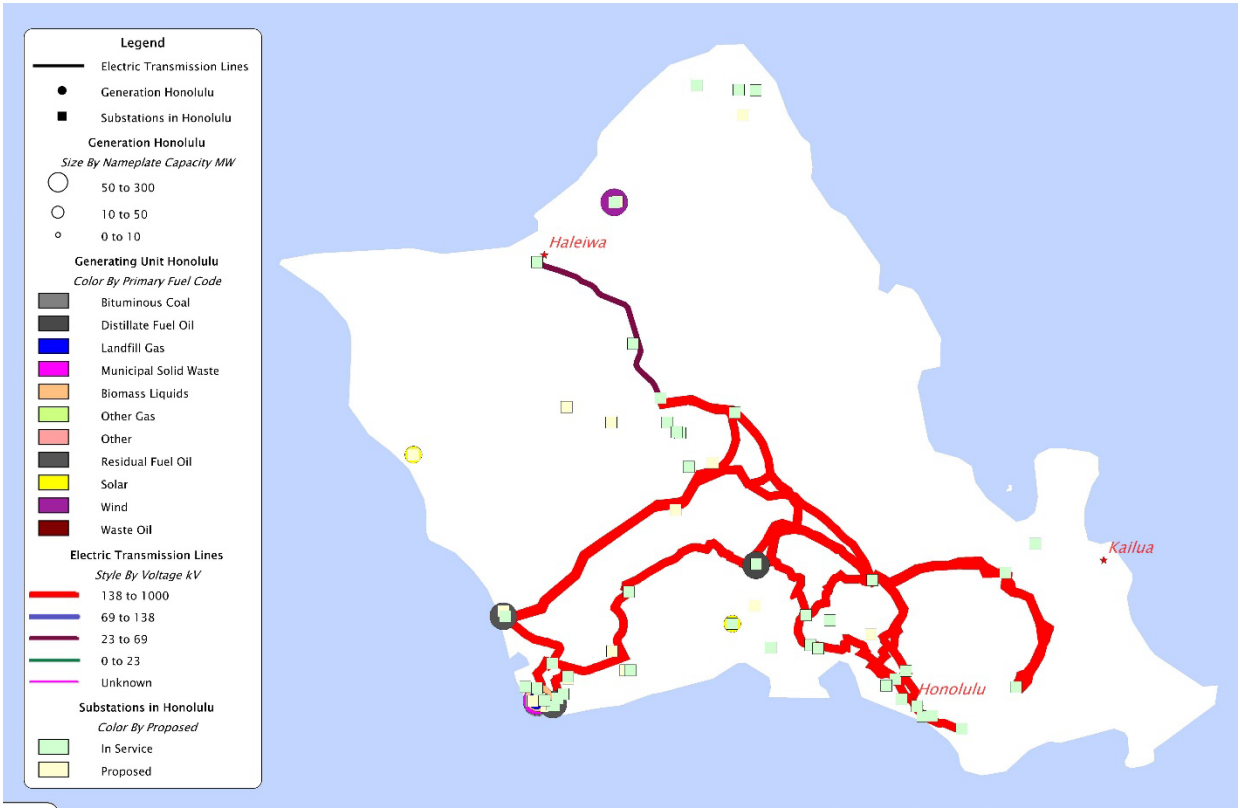
Source: Created the map using the Energy Velocity Suite

[27] The voltage, in kilovolts, of the largest feature from the Electric Transmission Lines that connects to the feature.

5 City and County of Honolulu

For practical purposes, the City and County of Honolulu is the island of Oahu. Oahu has a land area of 600.7 square miles. While the smallest of the four counties in geographical size, it has 70% of the State's population (992,605).[28] Downtown Honolulu is the center of business and government for the State of Hawaii.

Figure 11. City and County of Honolulu electric facilities



Source: Created the map using the Energy Velocity Suite

The City and County of Honolulu's total net capacity as of September 2017 is about 2,330 MW, including plants which came online in the past year such as Waianae Solar (27.6 MW), Waipio Solar (14.3 MW), Waihonu Solar (6.5 MW), and the Daniel K. Inouye International Airport Emergency Generating Station (8 MW), as well as 72.3 MW of DGPV as forecasted for 2017 in PSIP.[29] HECO is the largest generation player in the county, owning about 51% of the net capacity.

[28] U.S. Census Bureau, Population Division.

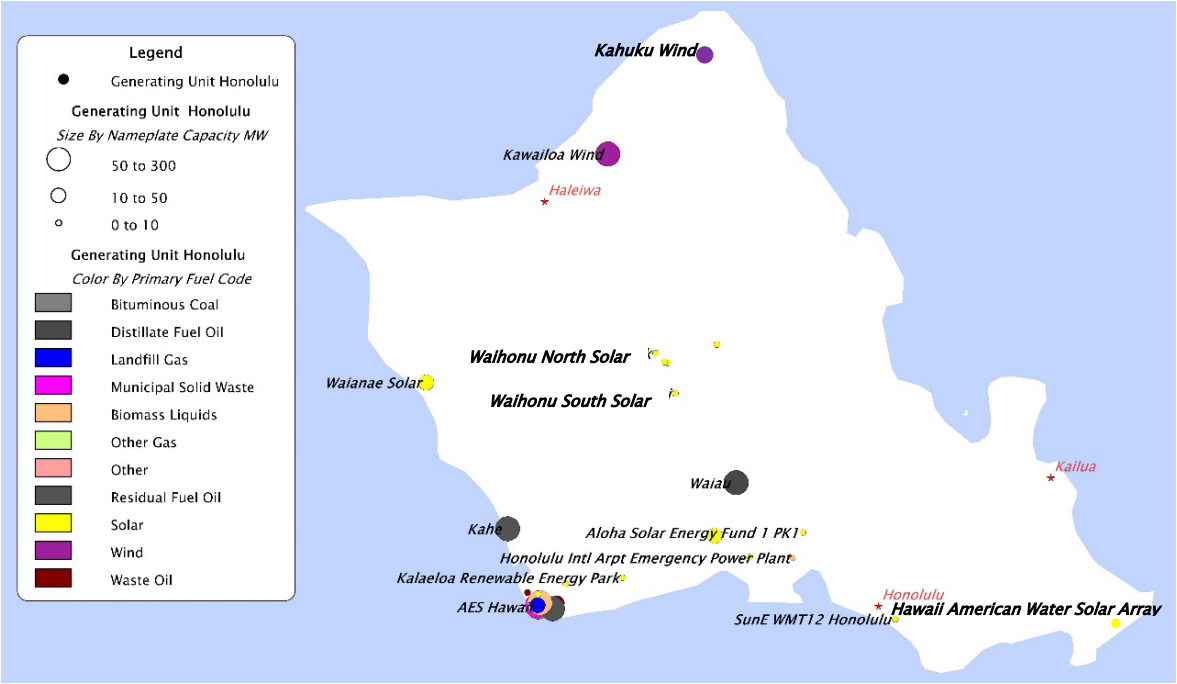
[29] Hawaiian Electric, Maui Electric, and Hawaii Electric Light ("HECO Companies"). *PSIP Update Report*. Book 2, page D-2, D-4. Book 3, page J-60. December 23, 2016. HECO Companies. *Power Facts*. April 2017. HEI Power Purchase Contracts factsheet.

The City and County of Honolulu is served by HECO with a total length of transmission line of about 817 miles. Figure 11 shows the map of the City and County of Honolulu electric facilities. The generation, transmission, and substation facilities are explained in detail below.

5.1 City and County of Honolulu generation facilities

Much like neighboring counties in the state, the City and County of Honolulu is dominated by oil-fired plants, which comprises 56% (1,296 MW) of the City and County of Honolulu's total net capacity. Honolulu also gets 8% of its capacity from coal through AES Hawaii (180 MW), the only coal plant in the State.[30] The remaining capacity comes mostly from wind, solar and biofuels.

Figure 12. City and County of Honolulu generation facilities



Source: Created the map using the Energy Velocity Suite

More than 692 MW of proposed generating resources are planned to be online in the next five years (from 2017 to 2021). These include[31]: 48.84 MW diesel (50%bio diesel) Schofield Plants (2018), 124.6 MW grid-scale PV (2018, 15MW CBRE), 34 MW onshore wind (2018, 10MW CBRE), 20 MW grid scale PV (2019), 30 MW onshore wind (2020), and 180 MW grid-scale PV (2020). In

[30] Hawaiian Electric, Maui Electric, and Hawaii Electric Light ("HECO Companies"). *PSIP Update Report*. Book 2, page D-4. December 23, 2016.

[31] Hawaiian Electric, Maui Electric, and Hawaii Electric Light ("HECO Companies"). *PSIP Update Report*. Book 1, page 6-11. December 23, 2016.

addition to these resources, 255 MW of DGPV is forecasted to be installed in the county through 2021.

HECO is the largest player in terms of installed capacity. There are also other independent power producers namely Kalaeloa Partners LP (owned by Harbert Management and PSEG) and AES Hawaii Inc. that own a combined net capacity of 388 MW (or 17% of the total capacity).[32]

5.2 City and County of Honolulu transmission facilities

Figure 13 shows the transmission facilities in the City and County of Honolulu. All the transmission facilities in the county are owned by HECO. Most of the transmission facilities in the City and County of Honolulu have higher capacity (at 138 kV) than in Hawaii County or Maui County. There are only two lines at 46 kV. As of December 2016, the total length of the transmission lines is about 817 miles.[33]

Figure 13. City and County of Honolulu transmission facilities



Source: Created the map using the Energy Velocity Suite

[32] Hawaiian Electric, Maui Electric, and Hawaii Electric Light ("HECO Companies"). *PSIP Update Report*. Book 2, page D-4. December 23, 2016. SNL Power Plant Profile. Accessed September 25, 2017.

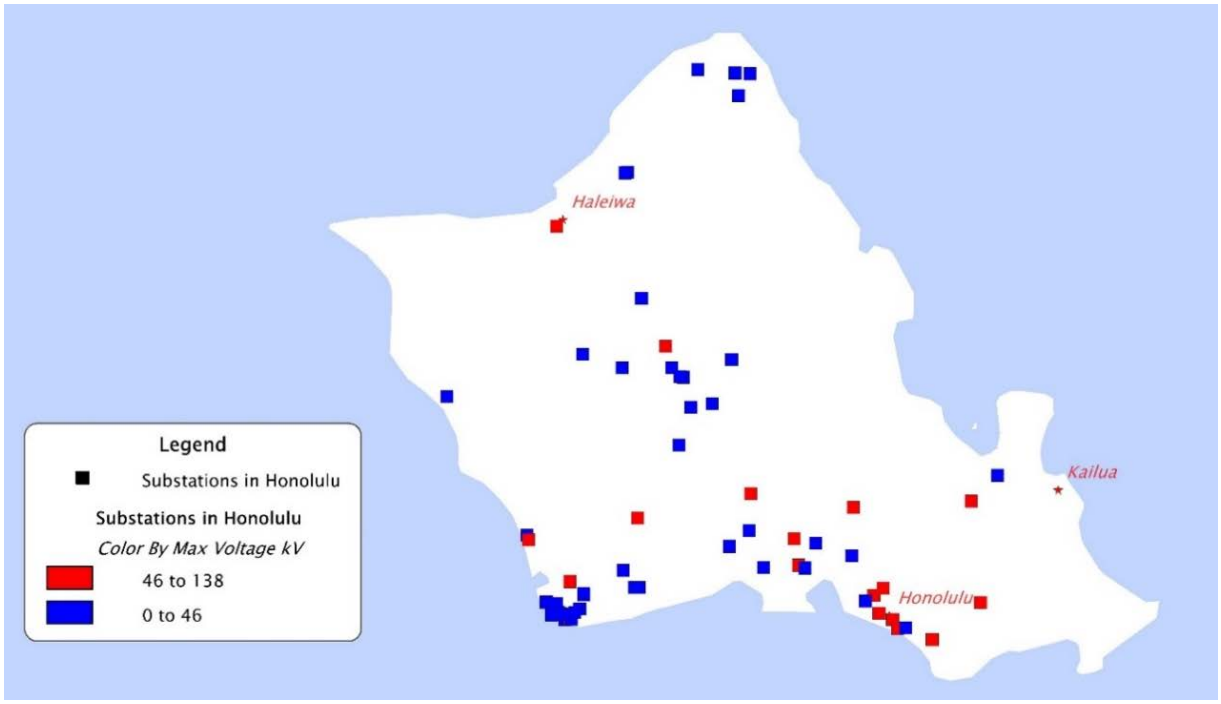
[33] Annual Financial Reports ("AFR") for Electric Utilities 2016.

5.3 City and County of Honolulu substation facilities[34]

There are 143 substations in the county, including 42 transmission substations, and 101 distribution substations. As of December 2016, 67% of the substations have no more than 30 MVA capacity in service in the county. Substations with greater capacity in service include Kahe Units 1,2,3,4 (a transmission substation, 396 MVA), Koolau (a transmission substation, 320 MVA), and Pukele (a transmission substation, 320 MVA).

When it comes to the capacity of transformers, 19 of the transmission substations have a primary voltage of 138 MVA, and 12 of them have a primary voltage of 46 MVA. The remaining transmission substations have a primary voltage ranging from 11.5 MVA to 25 MVA. As for distribution substations, most of them have a primary voltage of 46 MVA, except Halekauwila substation with a primary voltage of 11.5 MVA, and Wailupe substation with a primary voltage of 12.5 MVA. As for the operating voltage, 138 kV[35] is the predominant operating voltage of substations in the county. Most of the blue squares shown in Figure 14 below represent substations.

Figure 14. City and County of Honolulu substation facilities



Source: Created the map using the Energy Velocity Suite

[34] Number of substations, capacity in service, and capacity of transformer are based on Annual Financial Reports ("AFR") for Electric Utilities 2016. Operating voltage and map itself is based on Velocity Suite database.

[35] The voltage, in kilovolts, of the largest feature from the Electric Transmission Lines that connects to the feature.

6 Kauai County

In Kauai County, only the island of Kauai has electric utility service. Kauai County has the smallest population (at 72,029 as of the 2016 estimation) among the counties reviewed in this study. The island of Kauai has a total land area of 562 of the county's 620 square miles.[36]

Figure 15. Kauai County electric facilities



Source: Created the map using the Energy Velocity Suite

Kauai County's total net capacity as of September 2017 is about 200 MW. Generating capacity is dominated by distillate fuel oil (45%). Kauai Island Utility Cooperative ("KIUC") is the largest generation player in the county with 71% of the total net capacity (or about 142 MW).[37]

Kauai County is served by KIUC. Its total length of transmission lines is approximately 171 miles.[38] The map of the Kauai County electric facilities is illustrated in Figure 15. The generation, transmission, and substation facilities are explained in detail below.

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[36] U.S. Census Bureau, Population Division.

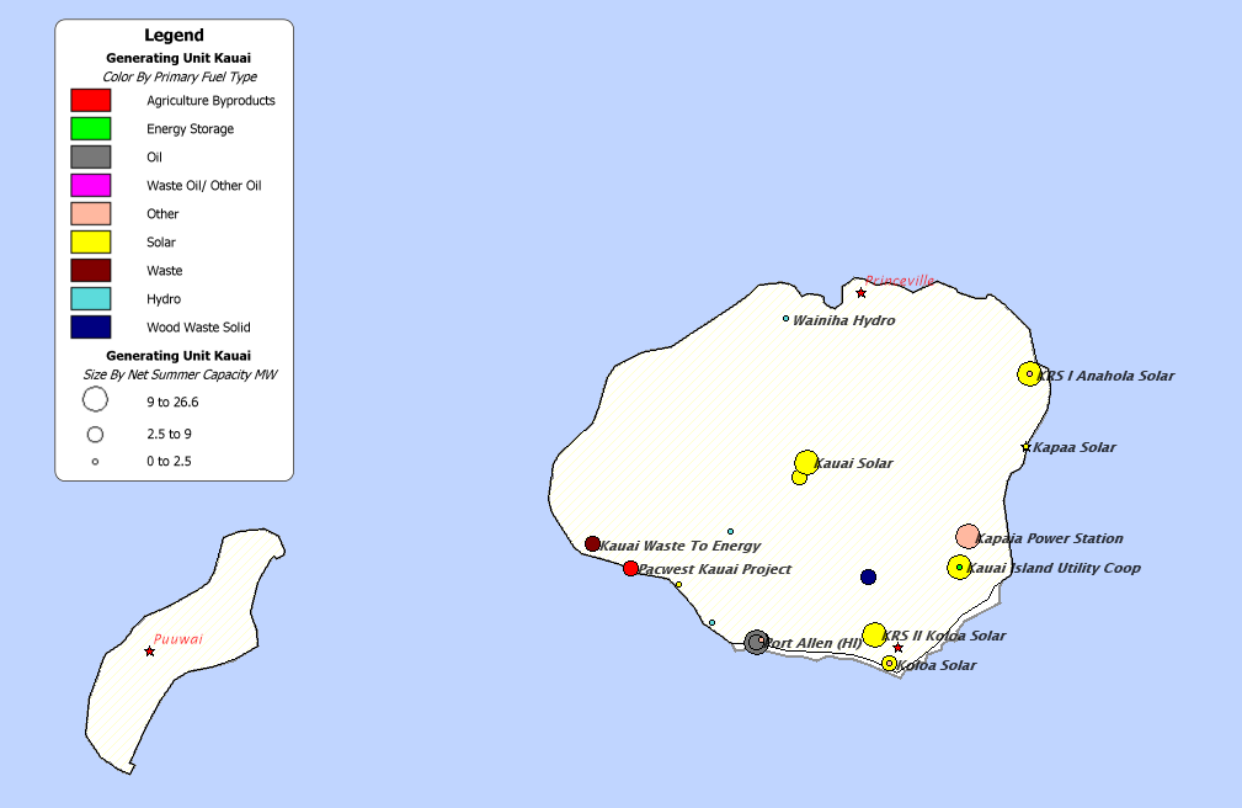
[37] KIUC. *Energy Information*. Website. Access date: July 26, 2017. <http://website.kiuc.coop/content/energy-information>. KIUC. *2017 Capital Improvements Program for Ensuing Five Years*. December 27, 2016.

[38] KIUC. *Currents*. June 2017. Page 8.

6.1 Kauai County generation facilities

Distillate fuel oil is the dominant fuel in the Kauai County generating capacity, as shown in Figure 16 below. It comprises 45% (90 MW) of the total net capacity in the county. Kauai has a relatively large share of solar in its fuel mix at 33%. Kauai's other fuels include naphtha (13%), hydro (5%), and biomass (3%).[39] There are also proposed generating resources in the county, including a 20 MW solar/ 100 MWh storage facility, 5MW DGPV, and 6 MW of hydro under construction or permitting, and 12 MW of hydro and 12 MW of solar plus storage under consideration.[40] In addition, KIUC also purchases power from hydro facilities operated by private companies with a combined capacity of 7.7 MW.[41]

Figure 16. Kauai County generation facilities



Source: Created the map using the Energy Velocity Suite

[39] KIUC. *Energy Information*. Website. Access date: July 26, 2017. <http://website.kiuc.coop/content/energy-information>. KIUC. *2017 Capital Improvements Program for Ensuing Five Years*. December 27, 2016.

[40] KIUC. *Kauai Island Utility Cooperative 2016 Annual Report*. December 31, 2016.

[41] KIUC. *Energy Information*. Website. Access date: January 11, 2018. <http://website.kiuc.coop/content/energy-information>.

As mentioned earlier, KIUC is the largest player in terms of installed capacity. Other generation players are Tesla Solar Storage, Green Energy Team, and McBryde, which collectively own a combined capacity of 32 MW or 16% of the total capacity in Kauai County.

6.2 Kauai County transmission facilities

Figure 17 shows the transmission facilities in Kauai County. All the transmission facilities are owned by KIUC. Most of the transmission facilities have a voltage of 69 kV. As of June 2017, the total length of the transmission lines is about 171 miles[42].

Figure 17. Kauai County transmission facilities



Source: Created the map using the Energy Velocity Suite

6.3 Kauai County substation facilities[43]

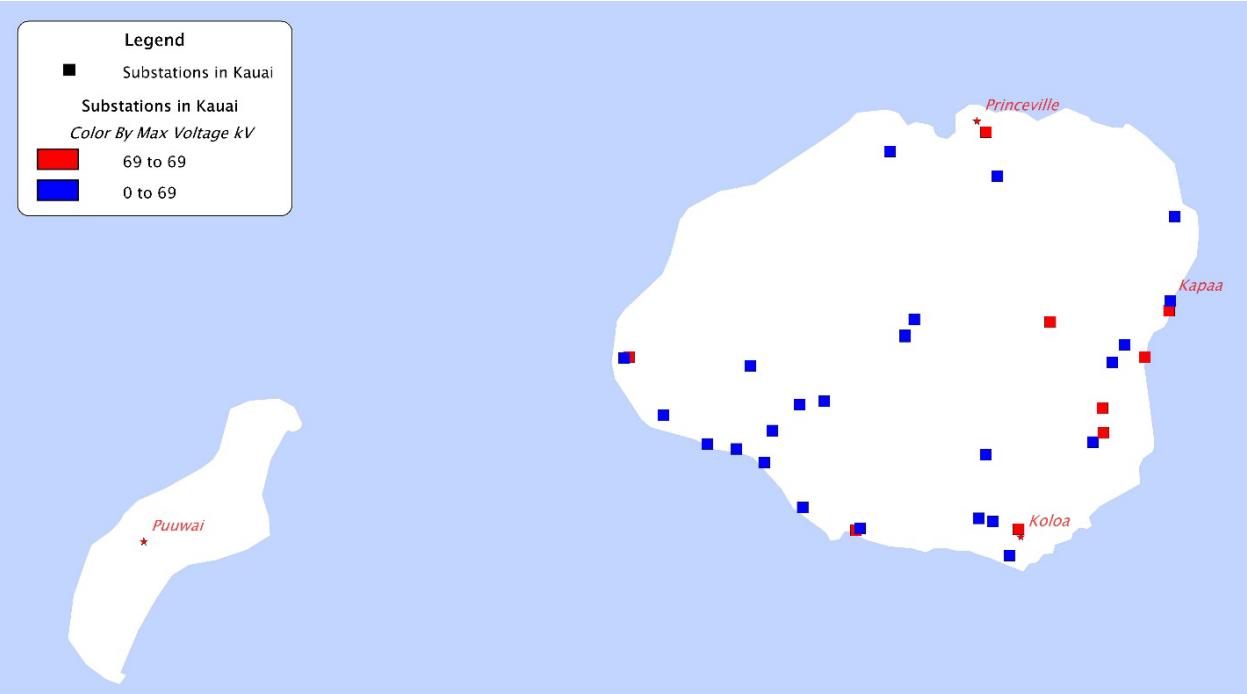
There are 26 substations in service, including five transmission substations and 21 distribution substations. The capacity of transformers of transmission substations ranges from as small as 4.16 MVA to 69 MVA. As for distribution substations, most of their transformers have a primary voltage of 69 MVA.

[42] KIUC. *Currents*. June 2017. Page 8.

[43] Number of substations and capacity of transformer are based on Annual Financial Reports ("AFR") for Electric Utilities 2016. Operating voltage and map itself is based on Velocity Suite database.

The predominant operating voltage of substations in Kauai County is 69 kV[44]. There are some proposed substations in the county, as shown in Figure 18.

Figure 18. Kauai County substation facilities



Source: Created the map using the Energy Velocity Suite

[44] The voltage, in kilovolts, of the largest feature from the Electric Transmission Lines that connects to the feature.

7 Appendix A: Scope of work to which this deliverable responds

Task 1.1.2 Maps for service areas of each county. CONTRACTOR shall prepare a map of the service area for each county. Each map shall delineate the generation, transmission, substation and distribution system facilities necessary to provide services.

DELIVERABLE FOR TASK 1.1.2. CONTRACTOR shall provide its conclusions and all work to provide maps for service areas of each county that delineate the various generation, transmission, substation, and distribution system facilities necessary to provide utility services. CONTRACTOR shall include narrative in MS Word, spreadsheets in MS Excel, and maps, as well as an index of all source information used to generate the maps. CONTRACTOR shall submit deliverable for TASK 1.1.2 to the STATE for approval.

8 Appendix B: List of works consulted

Hawaiian Electric, Maui Electric, and Hawaii Electric Light ("HEI"). *PSIP Update Report*. December 23, 2016. HPUC Docket 2014-0183. Book 2. <https://www.hawaiianelectric.com/Documents/about_us/our_vision/dkt_2014_0183_20161223_companies_PSIP_update_report_2_of_4.pdf>

HECO. *Annual Report of Hawaiian Electric Company, Inc.to the Public Utilities Commission, State of Hawaii*. December 31, 2016.

HELCO. *Annual Report of Hawaii Electric Light Company, Inc.to the Public Utilities Commission, State of Hawaii*. December 31, 2016.

KIUC. *Annual Report of Kauai Island Utility Cooperative to the Public Utilities Commission, State of Hawaii*. December 31, 2016.

KIUC. *2017 Capital Improvements Program for Ensuing Five Years*. December 27, 2016.

KIUC. *Energy Information*. Website. Access date: July 26, 2017. <http://website.kiuc.coop/content/energy-information>

MECO. *Annual Report of Maui Electric Company, Limited to the Public Utilities Commission, State of Hawaii*. December 31, 2016.

S&P Global Market Intelligence . SNL Mapping Application. Access date: July 13th, 2017.

SNL News. Access date: September 25th, 2017.

SNL Power Plant Profile. Access date: September 25th, 2017.

Velocity Suite. Electric Infrastructure Dataset. Access date: June 8th, 2017.

Velocity Suite. Intelligent Map Work Space. Access date: June 8th, 2017.

Existing generation, transmission, and distribution infrastructure in Hawaii

prepared for Hawaii Department of Business, Economic Development, & Tourism by London Economics International LLC

February 14, 2018

London Economics International LLC ("LEI") has been selected by the Hawaii Department of Business, Economic Development and Tourism ("DBEDT") to perform a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. As part of this engagement, one of the tasks (specifically, Task 1.1.3) involves providing a Microsoft ("MS") Excel spreadsheet on the existing (operating) generation, transmission, and distribution asset infrastructure in each county in Hawaii that is served by an electric utility. This document accompanies the Excel dataset and explains the sources of the data contained there.

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List of acronyms

AFR	Annual Financial Reports for Electric Utilities
CEMS	Continuous Emission Monitoring Systems - United States Environmental Protection Agency | US EPA
DBEDT	Hawaii Department of Business, Economic Development and Tourism
DGPV	Distributed generation photovoltaic
EIA	US Energy Information Association
FERC	Federal Energy Regulatory Commission
HECO	Hawaiian Electric Company
HEI	Hawaiian Electric Industries Inc.
HELCO	Hawaii Electric Light Company
ISOs	Independent System Operators
KIUC	Kauai Island Utility Cooperative
kV	Kilovolt
LEI	London Economics International LLC
MECO	Maui Electric Company
MS	Microsoft
MVA	Mega-volt ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
PSIP	Power System Improvement Plan
USGS	United States Geological Survey

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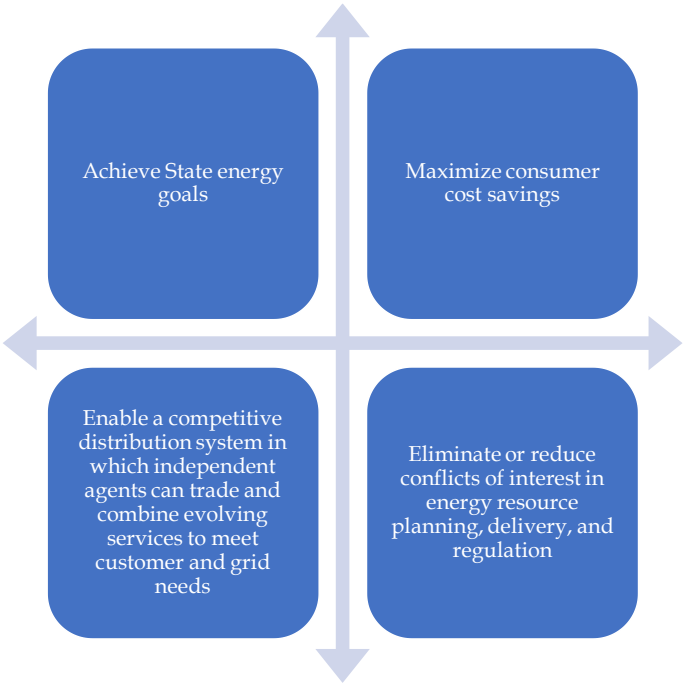
1 Introduction and scope

1.1 Project description

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the State's legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals of 100% renewable energy by 2045. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[1] was contracted to perform this study.[2]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[3] listed in Figure 1.

Figure 1. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595.

The study will also help in understanding the long-term operational and financial costs, as well as the benefits of electric utility ownership and regulatory models to serve each county of the State. In addition, it will also aid in identifying the process to be followed to form such ownership

[1] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[2] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[3] House Bill No. 1700 Relating to the State Budget.

and regulatory models, as well as help determine whether such models would create synergies in terms of:

- increasing local control over energy sources serving each county;
- ability to diversify energy resources;
- economic development;
- reducing greenhouse gas emissions;
- increasing system reliability and power quality; and lowering costs to all consumers.[4]

1.2 Role of this deliverable relative to others in the project

This deliverable is responsive to Task 1.1.3 in the project scope of work (the scope of work for Task 1.1.3 is outlined in Section 0). Task 1.1.3 requires the submission of an MS Excel spreadsheet of existing generation, transmission, substation and distribution facilities in each county. In addition, the database includes detailed information regarding the age and condition of the assets in each county. The database will allow further analysis from various perspectives as noted in the assigned task.

1.3 Future refinements

The provided database is subject to further refinement/updates as new information surfaces throughout the timeline of the project. Data updates will include any future additions to generation, transmission, and distribution assets in any of the counties.

[4] Hawaii Contract No. 65595. Scope of Services.

2 Overview of the existing assets database

The attached MS Excel spreadsheet includes detailed data on existing (currently operating) generation, transmission, substation and distribution asset infrastructure in each county of Hawaii State. These counties include: Hawaii County (Island of Hawaii), Honolulu County (Island of O'ahu), Maui County (Islands of Maui, Lana'i, Moloka'i, and Kaho'olawe), and Kauai County (Island of Kauai). The generation data also includes information on the age, commercial online date, nameplate capacity, net summer capacity, and net winter capacity. The transmission data includes voltage, line length, type of line, and names of starting and ending substations, if available. The substation data includes details on voltages, the capacity of substations, and the number of transformers, as well as capacitors, if available.

2.1 Data in the Excel dataset

The dataset includes three major categories of data: generation assets, transmission assets, and distribution/substation assets. Each asset category includes separate tabs (with assigned colors) for each of the counties.

The Excel file also includes a cover tab, as well as tabs titled 'Log' and 'Abbreviations' which were included to assist DBEDT to keep track of and understand the information included in the Excel file. The color codes, table numbers, and names of the main datasets are listed in the 'Log' tab. The 'Abbreviations' tab includes abbreviations for fuel and technology types, as well as several definitions of fields used in the data sheets for clarity.

Figure 2. Main data tables and sources

Asset Category	Tab Contents	Sources
Generation asset data	Generation asset data (operating units)	HEI 2016 PSIP, AFR for Electric Utilities (FERC Form No.1), EIA, Hawaiian Electric Power Facts, HEI Power Purchase Contracts, KIUC website, KIUC 2017 Capital Improvements Program for Ensuing Five Years, SNL Power Plant Profile
	Table 1.1 Hawaii County Gen	
	Table 1.2 Maui County Gen	
	Table 1.3 Honolulu County Gen	
	Table 1.4 Kauai County Gen	
Transmission asset data	Transmission asset data	AFR for Electric Utilities (FERC Form No.1), Energy Velocity (for Kauai county)
	Table 2.1 Hawaii County Transmission	
	Table 2.2 Maui County Transmission	
	Table 2.3 Honolulu County Transmission	
	Table 2.4 Kauai County Transmission	
Substation asset data	Substation asset data	AFR for Electric Utilities (FERC Form No.1)
	Table 3.1 Hawaii County Substation	
	Table 3.2 Maui County Substation	
	Table 3.3 Honolulu County Substation	
	Table 3.4 Kauai County Substation	

2.2 Approach in collecting and putting together the database

The attached data was collected from various publicly available sources, including: FERC Form 1 filings, utility websites, subscription to third-party providers, and data provided by Hawaiian Electric Companies ("HECO Companies"). The data provided from the various sources listed were cross-checked to ensure a comprehensive and detailed overall report.

2.3 Sources of data

The following section includes a list of all sources used to compile the data in the attached Excel database. This list includes the name of all sources, including the specific publicly available documents and filings provided by each source.

- FERC Form No. 1 for electric utilities
- Hawaiian Electric Companies 2016 Power Supply Improvement Plans ("PSIP")
- Hawaiian Electric Companies website
- Hawaiian Electric Power Facts
- HEI Power Purchase Contracts
- Kauai Island Utility Cooperative ("KIUC") website
- KIUC 2017 Capital Improvements Program for Ensuing Five Years
- Hawaii State Energy Office: Hawaii Renewable Energy Project Directory
- US Energy Information Association ("EIA")
- SNL Financial – is a paid third-party database provider and is part of S&P Global Market Intelligence.[5] SNL sources their generation data from the EIA 923 Survey Form
- Energy Velocity ("EV") – is a third-party database provider owned by the ABB Group.[6] EV sources their information from publicly available sources, namely:

    - EIA 860 Form
    - FERC Form 1
    - North American Electric Reliability Corporation - Energy Supply & Demand database
    - Continuous Emission Monitoring Systems (US EPA)
    - U.S. Federal and State Agencies
    - Unit Owner
    - ABB Primary Research

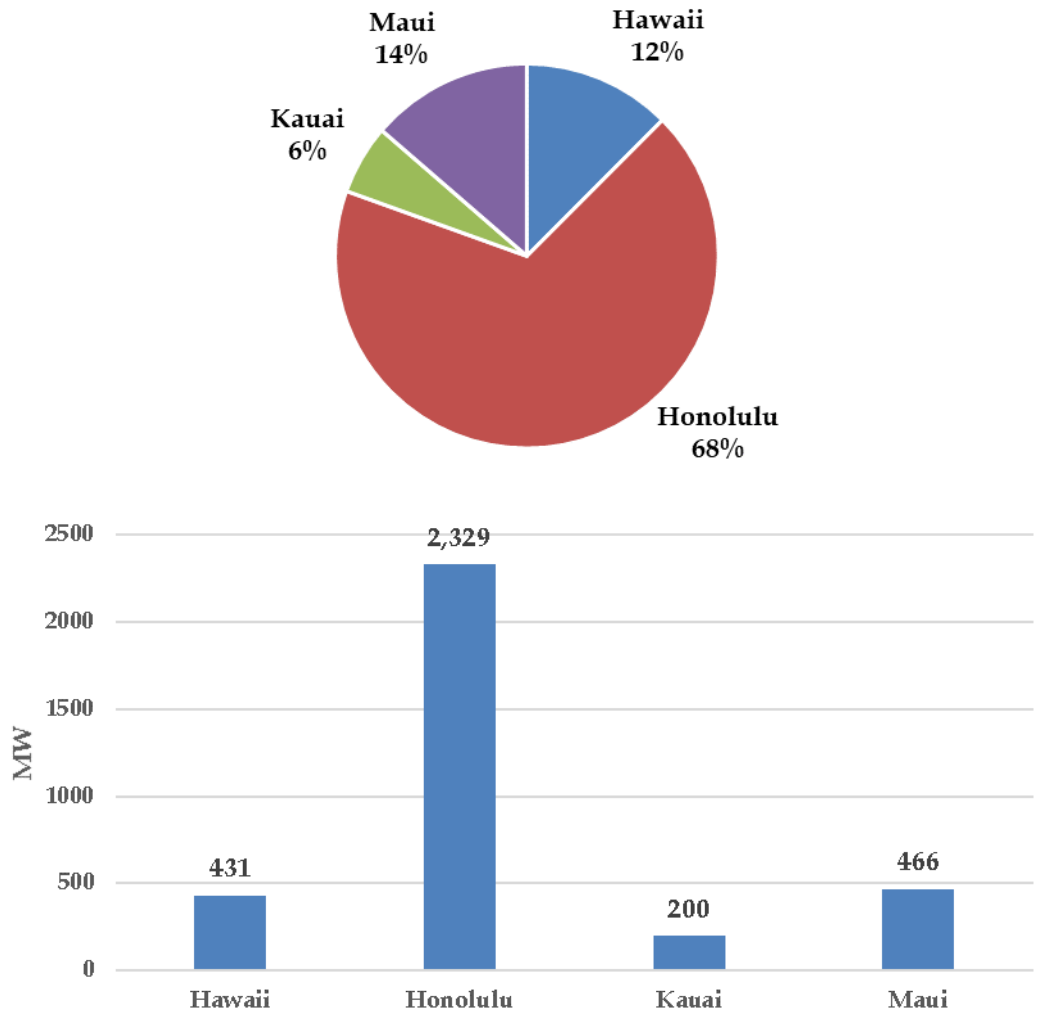
[5] For more information about SNL, please visit to their website at https://marketintelligence.spglobal.com/about-us/about-us.html.

[6] For more information about Energy Velocity, please visit their website at http://new.abb.com/enterprise-software/energy-portfolio-management/market-intelligence-services/velocity-suite

3 Overview of the existing generation, transmission, and distribution infrastructure in Hawaii

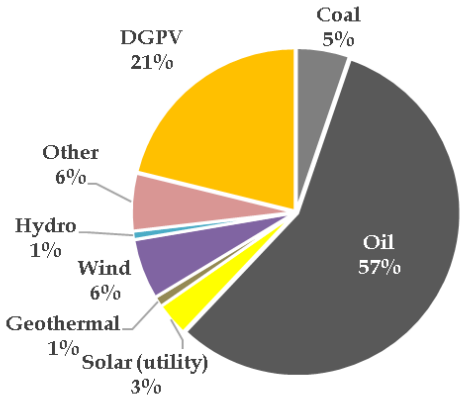
As of August 2017, the total installed capacity in the State of Hawaii is 3,427 MW. Honolulu County has the highest percentage of installed capacity, representing almost 68% of the State's installed capacity. This is followed by Maui, Hawaii, and Kauai respectively.

Figure 3. Hawaii State installed capacity, by county



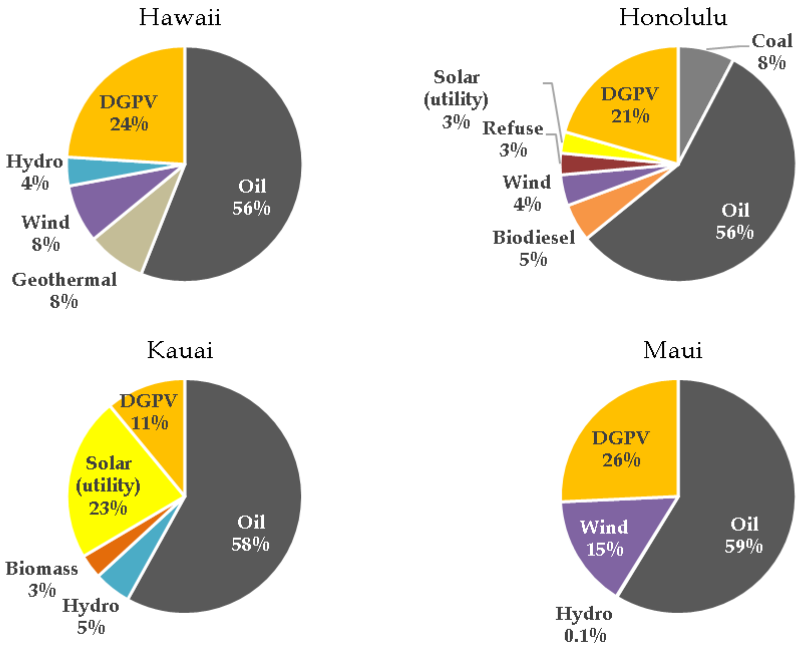
More than half of the State's capacity utilizes oil, while almost a quarter is from solar, as shown in Figure 4. This is also the case for each county, as shown in the pie chart below. Although Honolulu has the largest capacity of solar in terms of total capacity, Kauai has the largest percentage of solar relative to its total installed capacity. Honolulu is the only county that has a coal-fired plant, while Hawaii County is the only county that has geothermal.

Figure 4. Hawaii State installed capacity, by fuel type



Note: Solar (utility) stands for utility-scale solar PV, and DGPV stands for distributed generation photovoltaic; diesel is included in Oil; Others include biomass, biodiesel, and refuse.

Figure 5. Installed capacity by fuel type, by county, and fuel type



Note: Statistics above include distributed generation; diesel is included in Oil.

In terms of ownership, Hawaiian Electric Industries ("HEI") subsidiaries HECO, MECO, and HELCO dominate the generation sector, owning about 50% of the installed capacity in the State. They are the largest generation companies in Honolulu, Maui, and Hawaii counties, while Kauai

Island Utility Cooperative ("KIUC") is the dominant generation company in Kauai County. There are also several independent power producers ("IPPs") in each county such as AES Corp, Tesla, Terraform Power, and Ormat Technologies, to name a few. Figure 6 and Figure 7 show the breakdown of the top generation players in the State and in each county, respectively. Task 1.1.2 maps out the generation plants for each county.

Figure 6. Hawaii State installed capacity, by generation owner

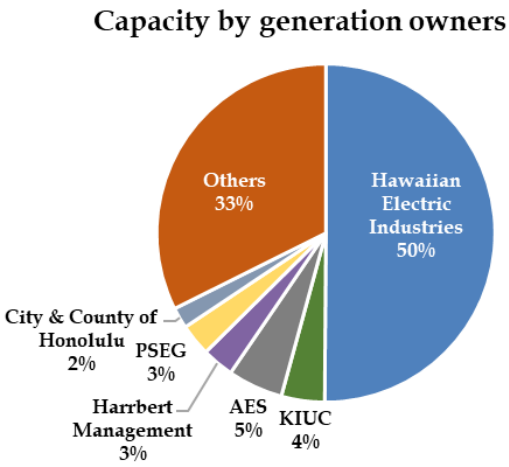
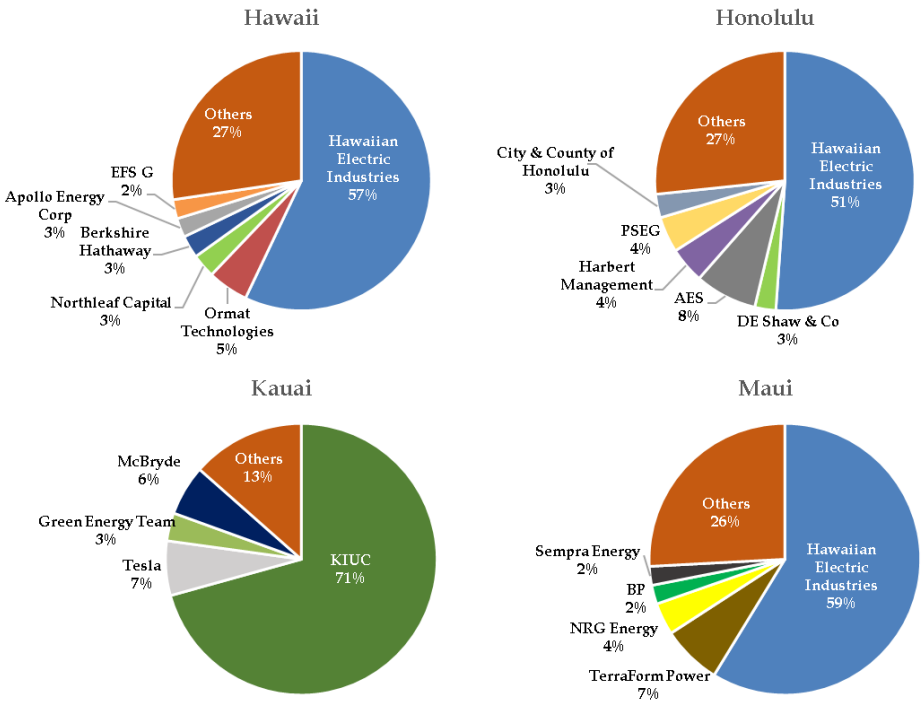


Figure 7. Installed capacity, by county and generation owner



Note: Others in the "capacity by generation players" include other IPPs and distributed generation.

Almost a third of the oil-fired generation capacity is from plants that are 40 – 49 years old, and more than a quarter from plants are 50 years or older. The average age of the 1,946 MW of oil-fired generation units in Hawaii is 39.5 years old. Figure 8 shows a breakdown of the age of thermal plants in the State. Nearly 59% of the oil-fired plants in Hawaii are above the average age of retirement for oil plants. Based on a sample of 148 retired plant units in the US, the average life of oil-fired plants is 39.7 years and ranges between 28 and 48 years old, depending on the technology, as shown in Figure 9 below. More than 50% of the oil-fired plants in the State are steam turbine while a quarter are combined cycle plants. The rest are either combustion gas turbine or internal combustion engine.

Figure 8. Age of oil-fired plants in the Hawaii State

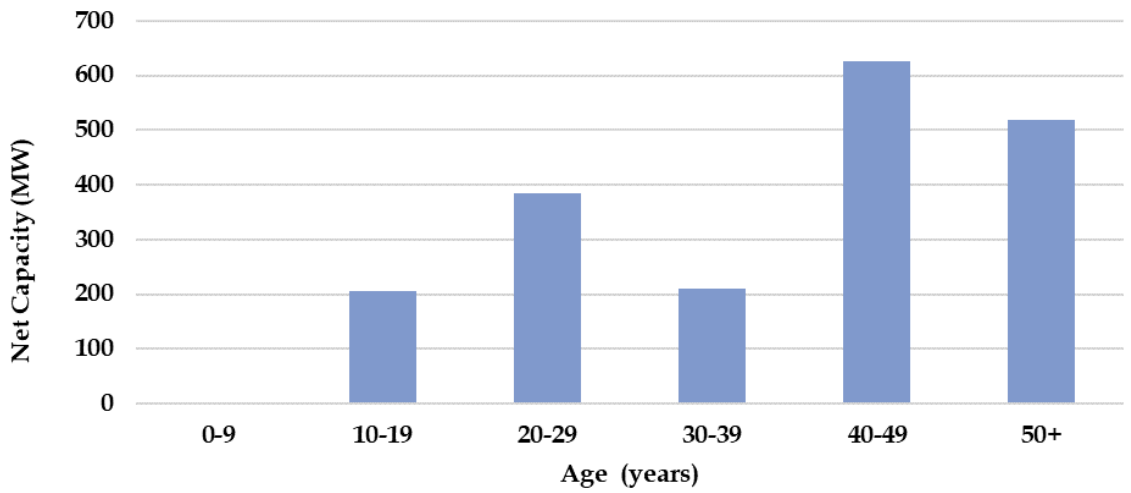


Figure 9. Average retirement age of oil-fired plants by technology in the US

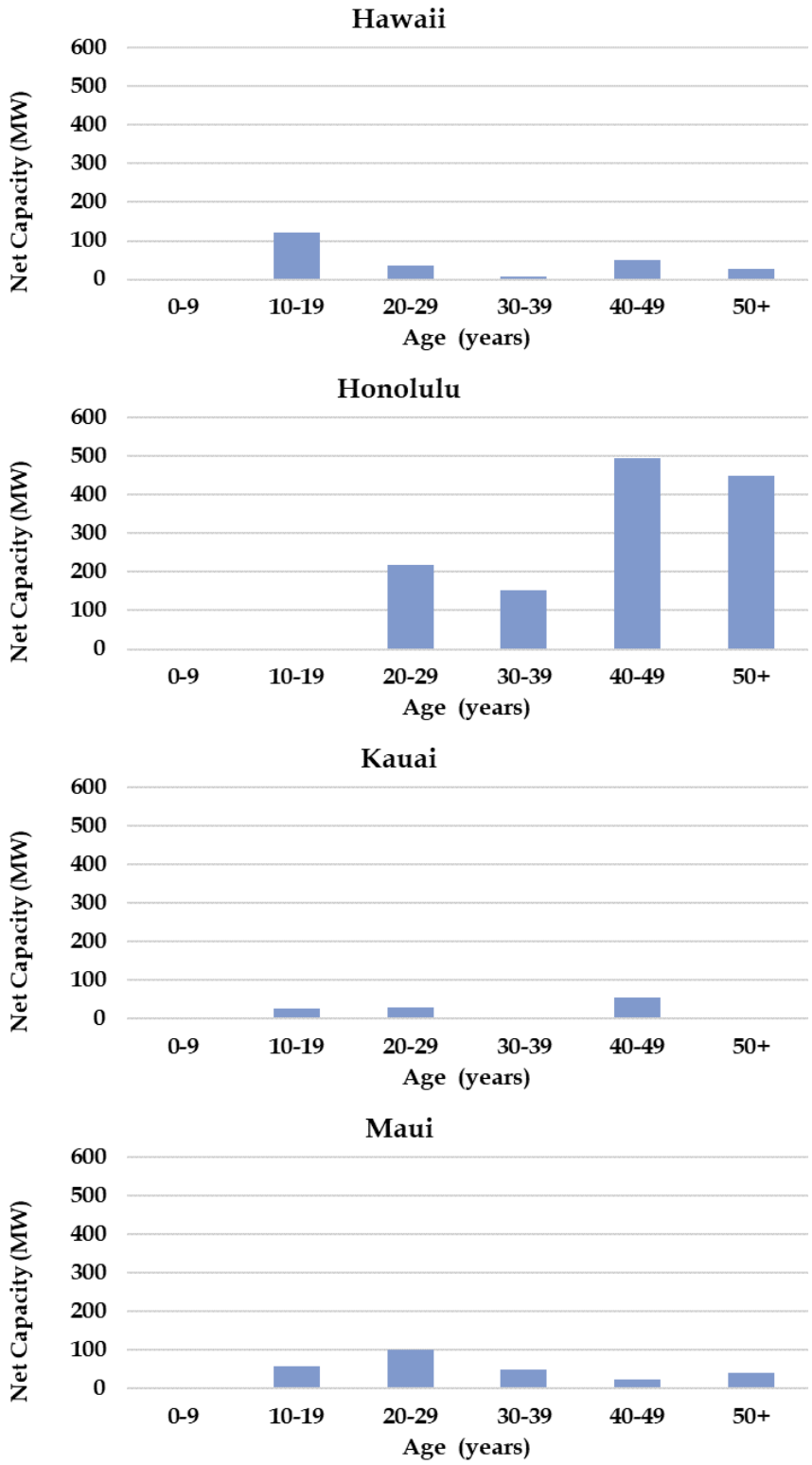
	Combustion Gas Turbine	Internal Combustion Engine	Steam Turbine
Distillate Fuel Oil	32	34	44
Residual Fuel Oil	28	45	48

Note: Based on 148 oil-fired retired in the US.
Source: Energy Velocity

As shown in Figure 10, all the counties have oil-fired plants that are older than 40 years. More than 900 MW of Honolulu's capacity is from oil-fired plants that are older than 40 years.

The solar plants in the State are relatively new, with the oldest one coming online in 2008. Likewise, wind plants are also largely new, with ages ranging between 5 and 11 years. The only coal-fired plant in the State came online in 1992 and is still within the typical useful life of a coal-fired plant.

Figure 10. Age of oil-fired plants, by county

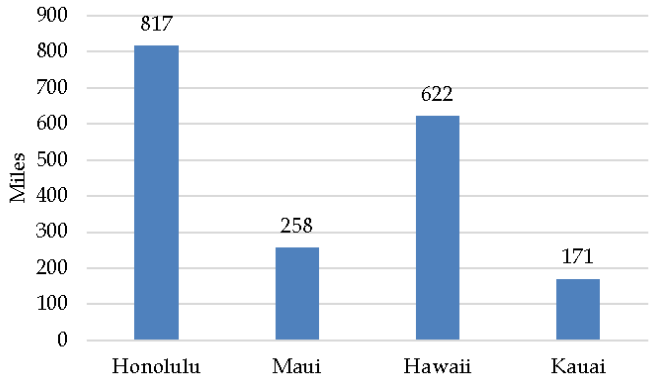


Source: PSIP

The total length of transmission lines in the State of Hawaii is approximately 1,868 miles, with Hawaii County representing the largest share at approximately 33% of the total.[7] Figure 11 shows the State's transmission miles by county.[8] The capacity of the transmission lines across all the four counties ranges from 13.8 kV – 138 kV[9] and the operating capacity of substations ranges from 25 MVA – 320 MVA.

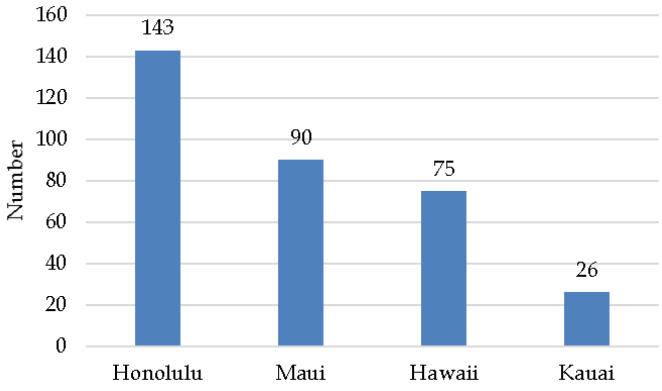
Figure 13 through Figure 16 show the key generation statistics for each county.

Figure 11. Hawaii State transmission lines, as of August 2017, by county



Source: HECO Companies' FERC Form 1 filings and KIUC website

Figure 12. Hawaii State number of substations (transmission and distribution), by county



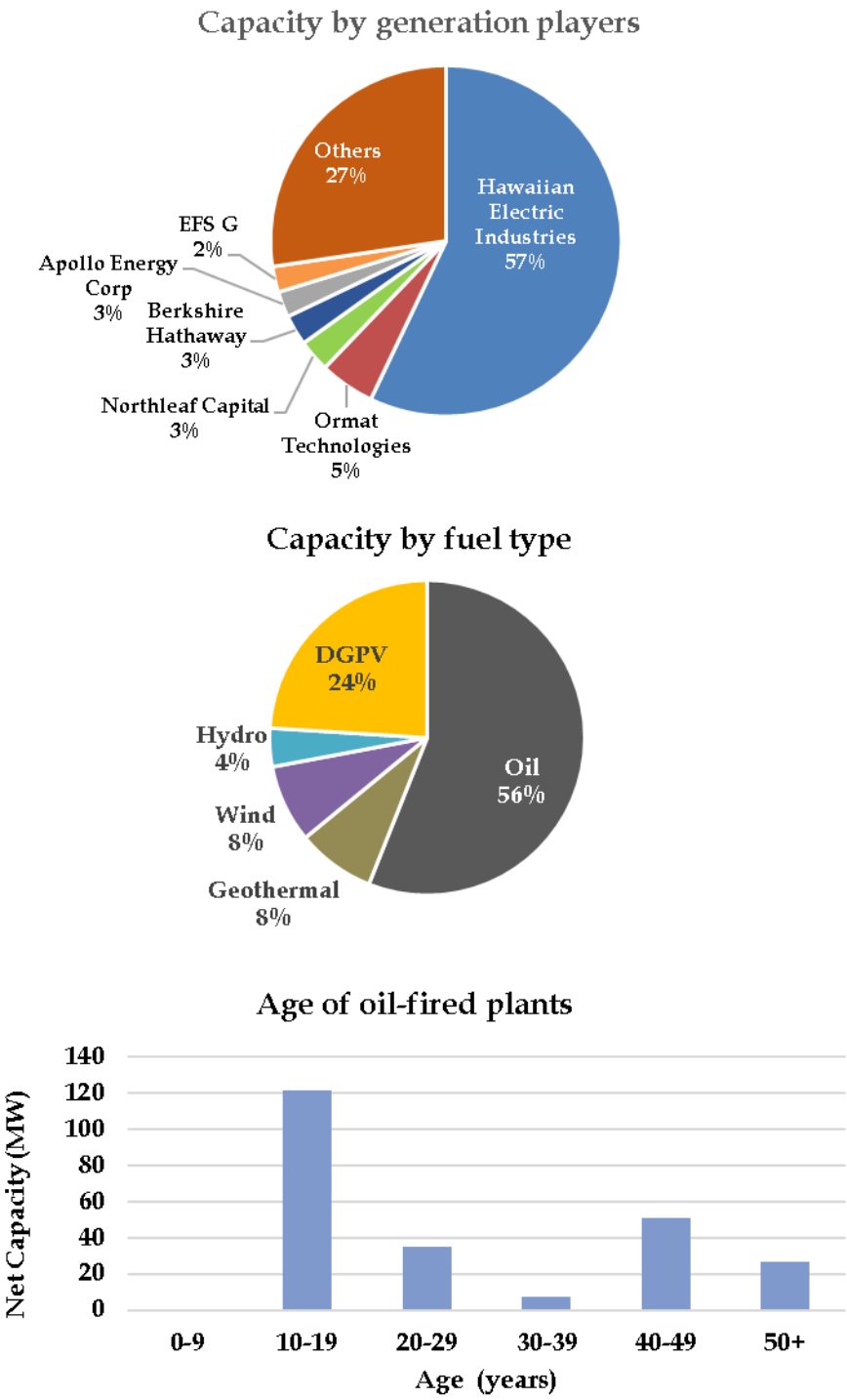
Source: Energy Velocity

[7] The reported length of transmission lines is sourced from FERC Form 1 filings as of December 31, 2016.

[8] Task 1.1.2 maps out the location of these transmission lines.

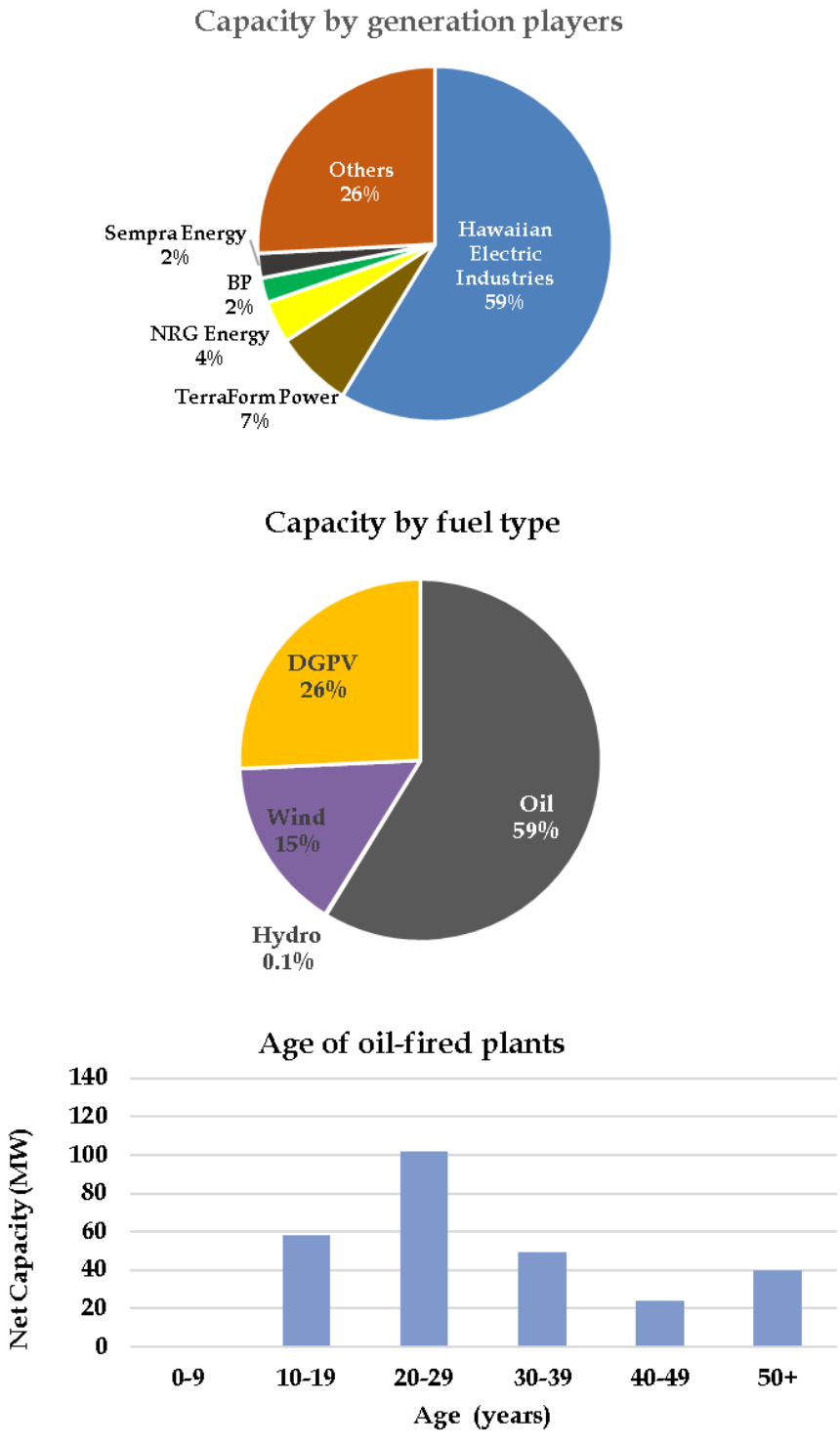
[9] Voltages of transmission lines usually vary from 69 kV to 765 kV. Source: NERC. *Glossary of Terms Used in NERC Reliability Standards*. Updated January 31, 2018.

Figure 13. Hawaii County key statistics



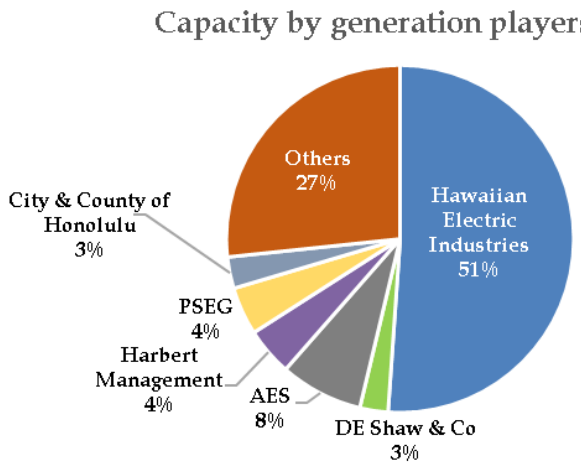
Notes:
(i) Solar (utility) stands for utility-scale solar PV, and DGPV stands for distributed generation photovoltaic.
(ii) Oil-fired plants include diesel plants, but not biodiesel.
(iii) Others in the "capacity by generation players" include other IPPs and distributed generation.

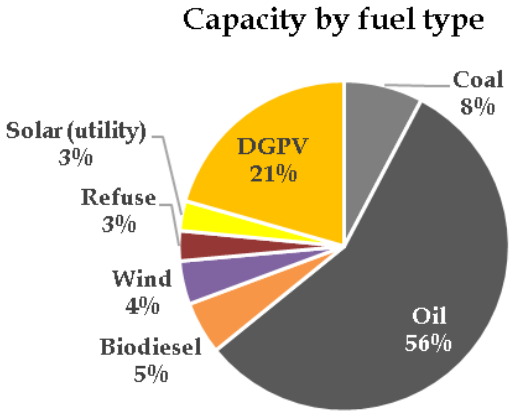
Figure 14. Maui County key statistics

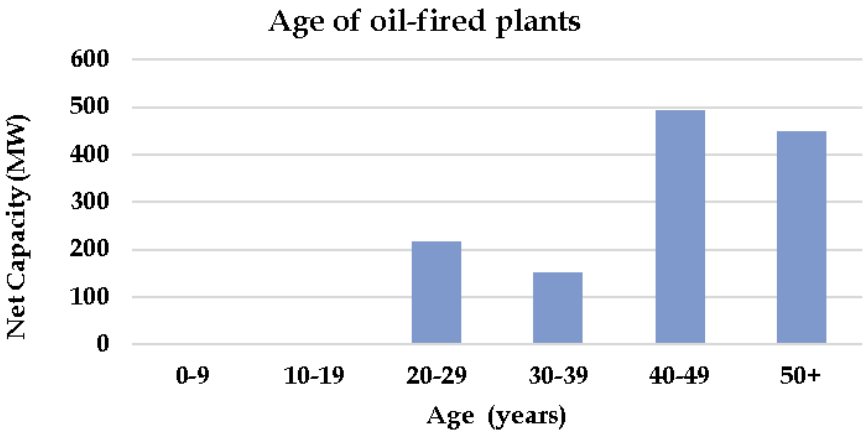


Notes:
(i) Solar (utility) stands for utility-scale solar PV, and DGPV stands for distributed generation photovoltaic.
(ii) Oil-fired plants include diesel plants, but not biodiesel.
(iii) Others in the "capacity by generation players" include other IPPs and distributed generation.

Figure 15. Honolulu County key statistics

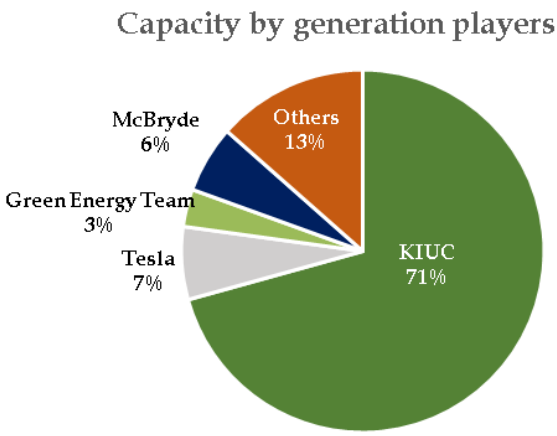


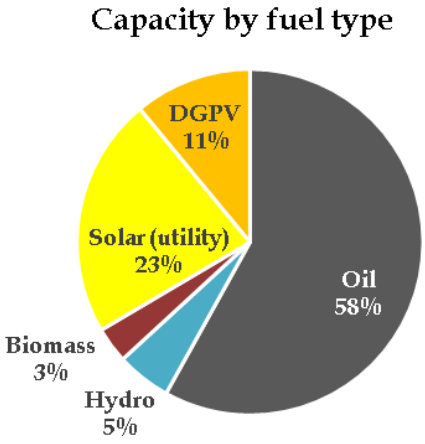


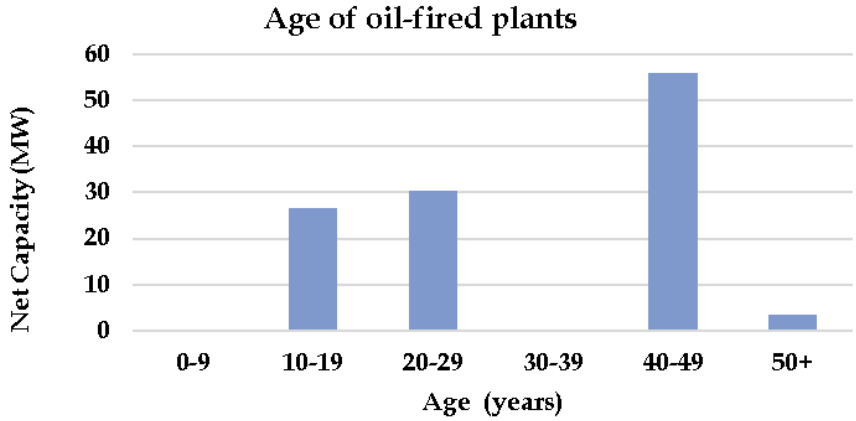


Notes:
(i) Solar (utility) stands for utility-scale solar PV, and DGPV stands for distributed generation photovoltaic.
(ii) Oil-fired plants include diesel plants, but not biodiesel.
(iii) Others in the "capacity by generation players" include other IPPs and distributed generation.

Figure 16. Kauai County key statistics







Notes:
(i) Solar (utility) stands for utility-scale solar PV, and DGPV stands for distributed generation photovoltaic.
(ii) Oil-fired plants include diesel plants, but not biodiesel.
(iii) Others in the "capacity by generation players" include distributed generation.

4 Appendix A: Scope of work to which this deliverable responds

Task 1.1.3. Assessment of existing generation, transmission and distribution infrastructure in each county.

CONTRACTOR shall provide a general assessment of the existing generation, transmission, substation and distribution facilities, including age and condition, located in each county required to provide and bill for service. CONTRACTOR shall list the number and type of meters currently in use in each county.

DELIVERABLE FOR TASK 1.1.3. CONTRACTOR shall provide its conclusions and all work to assess the existing generation, transmission and distribution infrastructure in each county. CONTRACTOR shall provide a database spreadsheet in MS Excel that produces metrics that allows analysis from a variety of perspectives, specifically by county, island, and meter type. CONTRACTOR shall submit deliverable for TASK 1.1.3 to the STATE for approval.

5 Appendix B: List of works consulted

Hawaii Electric, Maui Electric, and Hawai'i Electric Light ("HEI"). *PSIP Update Report*. December 23, 2016. HPUC Docket 2014-0183. Book 2. <https://www.hawaiianelectric.com/Documents/about_us/our_vision/dkt_2014_0183_20161223_companies_PSIP_update_report_2_of_4.pdf>

HECO. *Annual Report of Hawaiian Electric Company, Inc.to the Public Utilities Commission, State of Hawaii*. December 31, 2016.

HELCO. *Annual Report of Hawaii Electric Light Company, Inc.to the Public Utilities Commission, State of Hawaii*. December 31, 2016.

KIUC. *2017 Capital Improvements Program for Ensuing Five Years.* December 27, 2016.

KIUC. *Annual Report of Kauai Island Utility Cooperative to the Public Utilities Commission, State of Hawaii*. December 31, 2016.

KIUC. *Energy Information*. Website. Access date: July 26, 2017. <http://website.kiuc.coop/content/energy-information>

KIUC. *Kauai Island Utility Cooperative Currents*. June 2017.

MECO. *Annual Report of Maui Electric Company, Limited to the Public Utilities Commission, State of Hawaii*. December 31, 2016.

S&P Global Market Intelligence. Access date: July – August 2017

SNL Power Plant Profile. Access date: September 25th, 2017.

Velocity Suite. Electric Infrastructure Dataset. Access date: June 8th, 2017.

Assessment of future needs for generation, transmission, and distribution infrastructure in each county

prepared for Hawaii DBEDT by London Economics International LLC

October 27, 2017





London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This document is one of several working papers issued as part of this engagement. Moving from an investor-owned utility ("IOU") to a cooperative ("co-op") or a municipal utility ("muni") will not require significant infrastructure investments since the infrastructure is already in place. However, moving to a Single Buyer model, regardless of the variant, and an integrated distributed energy resource ("IDER") system operator would require some investments in setting up the systems, protecting data, and facilitating market participation for customers, DER providers, and other service providers.

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List of acronyms

ADMS	Advanced Distribution Management System
AFR	Annual Financial Reports for Electric Utilities
AGC	Automatic Generation Control
DBEDT	Hawaii Department of Business, Economic Development and Tourism
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DMS	Distribution Management System
DOC	Distribution Operations Center
DSIP	Distributed System Implementation Plan
DSP	Distributed System Platform
EMS	Energy Management System
EV	Electric Vehicle
FCI	Faulted Circuit Indicators
GIS	Geographic Information System
HECO	Hawaiian Electric Company
HEI	Hawaiian Electric Industries Inc.
HELCO	Hawaii Electric Light Company
IDER	Integrated Distributed Energy Resources
ISO	Independent System Operator
JU	Joint Utilities of New York
KIUC	Kauai Island Utility Cooperative
kV	Kilovolt
kWh	Kilowatt-hours
LEI	London Economics International LLC

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MDMS	Meter Data Management System
MECO	Maui Electric Company
MW	Megawatt
NOC	Network Operations Center
OMS	Outage Management System
OPA	Ontario Power Authority
PSC	Public Service Commission
PSIP	Power Supply Improvement Plan
REV	Reforming the Energy Vision
RPS	Renewable Portfolio Standards
SB	Single Buyer
SCADA	Supervisory Control and Data Acquisition
SVC	Secondary VAR Controllers
T&D	Transmission and Distribution
TNB	Tenaga Nasional Berhad
VVO	Voltage/VAR Optimization

1 Executive Summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which responds to Task 1.1.4 in the project scope of work, identifies, on a high level, the generation, transmission, and distribution infrastructure investments needed in the future under different electric utility ownership models. We have also compared the options against the current investment plans of the incumbent utilities.

The three subsidiaries of Hawaiian Electric Industries ("HEI"), known here collectively as the HECO Companies, have filed two comprehensive documents namely the Power Supply Improvement Plan Update Report ("PSIP") and Modernizing Hawaii's Grid For Our Customers ("Grid Modernization" document), in which they discuss in detail the investments in infrastructure and operating capability necessary to replace aging assets and also accommodate higher levels of distributed energy resources ("DERs") on the grid. Infrastructure investments could be in new renewable energy and DER capacity (Figure 7 and Figure 8) or in advanced grid technologies (Figure 9). Operational reliability in the future grid will also require new methods and technologies, as detailed in Figure 10. According to the HECO Companies' PSIP plan, the utilities will invest $9.4 billion between 2017 and 2045, including about $295 million in power supply assets and $91 million in smart grid investments. The Grid Modernization document provides further detail and estimates $205 million in investments in new technologies and software between 2018 and 2023. As a result, the average utility bill will rise between $0.94/month and $2.07/month over the next 10 years in the three counties served by the HECO Companies. In Kauai, the Kauai Island Utility Cooperative ("KIUC") plans to generate at least 70% of electricity from renewables by 2030 but by limiting incremental renewable generation in a year to no more than 20% of Kauai's load in that year.

Based on the Project Team's high level and preliminary analysis, a different ownership model will not dramatically change the infrastructure needed, especially in grid modernization technologies. More specifically, there will not be any material differences in infrastructure requirements if a utility moved from an investment owned utility ("IOU") to the cooperative or municipal utility models, whereas a grid defection scenario results in significant stranded assets. Currently, the incumbent utilities, HECO Companies and KIUC, already have the infrastructure in place to manage and operate the electricity systems. In addition, the roles and responsibilities of the owner under the new ownership model would be the same.

On the other hand, the Single Buyer ("SB") model will require new infrastructure investments initially to set up the SB, whether as a stand-alone entity or a ring-fenced unit within the existing utility. The checklist to set up a SB under either variant of the model is largely the same, but some of the technology and capability needed for more sophisticated resource planning may have to

be duplicated in the SB and the utility.[1] Under this model, there is the potential to lower utility investments in generation capacity if other capacity providers can meet system needs at a lower cost. Ontario Power Authority, an example of a Single Buyer in Ontario, Canada, spent more than CAD$3.5 million (in 2005 dollars) in capital expenditures during its first year of operation. This amount includes items such as furniture, computer hardware and software, telephone system, and leasehold improvements. For Hawaii, we anticipate that each county will spend less than this amount given the anticipated smaller size of the office for the Single Buyer and the technological improvements and decline in costs of these items in the past few years.

Figure 1. Summary of infrastructure and capability needed to move to another utility ownership model

Utility ownership model	Infrastructure and capability needed to move to another utility ownership model
IOU	None
Co-op	None
Municipal utility	None
Single Buyer	Separate accounts and operations, including office workspace, staffing, accounts, financial reporting, IT, compliance reporting.
	Monitoring and dispute resolution capability in regulatory body.
	Capability to conduct load/DER forecasting, resource planning.
	Run competitive tenders.
	Contract management.
	Maintain online information portal with equal access to resources for all parties.
IDER system operator	Divestment from generation.
	Capability to conduct system planning, determine DER pricing.
	Blockchain or similar system to manage distributed grid with multiple nodes and peer-to-peer transactions.
	Online portals for DER sourcing, system data, hosting capacity maps, streamlined interconnection.
	Ecosystem to share and analyze system and customer data.
	Cybersecurity infrastructure to secure customer privacy.
Grid defection	None

In the integrated distributed energy resource ("IDER") model, the incumbent vertically integrated utility must divest from its generation business and will only own the wires[2] assets. Therefore, the utility investments under an IDER model will be focused on the advanced grid technologies, similar to those proposed by the HECO Companies. KIUC has already achieved high levels of DER and smart meters deployment and intends to focus on increasing utility-scale renewable generation rather than further encouraging growth of DERs. However, the IDER model will eventually see peer-to-peer transactions across the distribution grid. The IDER system operator, which can be the utility or an independent entity, will need to manage energy and payment flows between many different market participants. This type of market operations will

[1] Detailed information of the steps to set up a Single Buyer, if chosen as one of the recommended utility ownership models, will be discussed in Task 1.3.1. - Identification of various steps, timeline, and costs required to change from current ownership model to new models, including regulatory approvals.

[2] Wires assets include transmission and distribution assets.

require additional investments to provide and protect data as well as to facilitate market participation for customers, DER providers, and other service providers. The Project Team looked at the pilot programs and enabling technologies used in New York and found that the infrastructure costs range between $11 and $190 million for the first five years of the pilot projects. The costs vary based on the technology, utility service area, and current status of utility infrastructure.

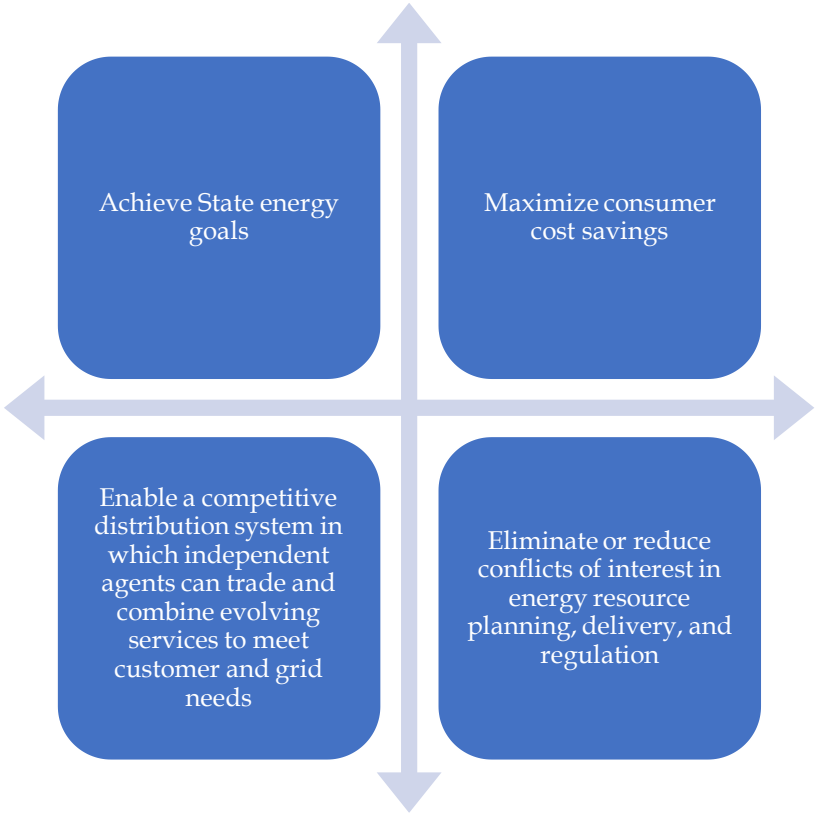
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2 Introduction and scope

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. LEI, through a competitive sealed proposals procurement,[3] was contracted to perform this study.[4]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[5] listed in Figure 2.

Figure 2. State's key criteria in evaluating the models



Source: Scope of Services under Contract No. 65595

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In

[3] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[4] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[5] House Bill No. 1700 Relating to the State Budget.

addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[6]

2.1 Role of this deliverable relative to others in the project

This deliverable is responsive to Task 1.1.4 in the project scope of work. It identifies, on a high-level approach, the generation, transmission, and distribution infrastructure investments needed in the future under different electric utility ownership models. It should be noted that sources used are based on publicly available information. Costs and steps required to transition to these ownership models are not discussed in this memo but will be examined under Task 1.3.1.[7]

2.2 Future refinements

As noted earlier, this deliverable is subject to further refinement and modification as the project moves forward and as we receive more information from the utilities on their future.

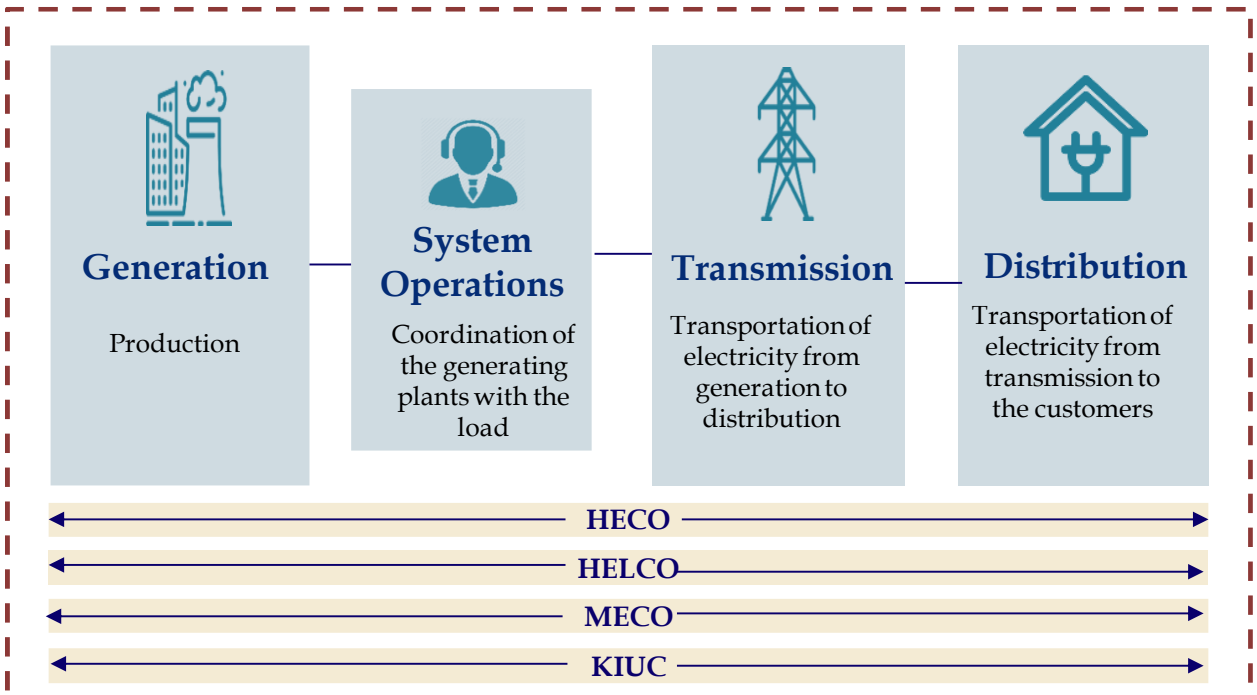
[6] Hawaii Contract No. 65595. Scope of Services.

[7] Task 1.3.1. Identification of various steps, timeline, and costs required to change from current ownership model to new models, including regulatory approvals.

3 Current structure and system in each county

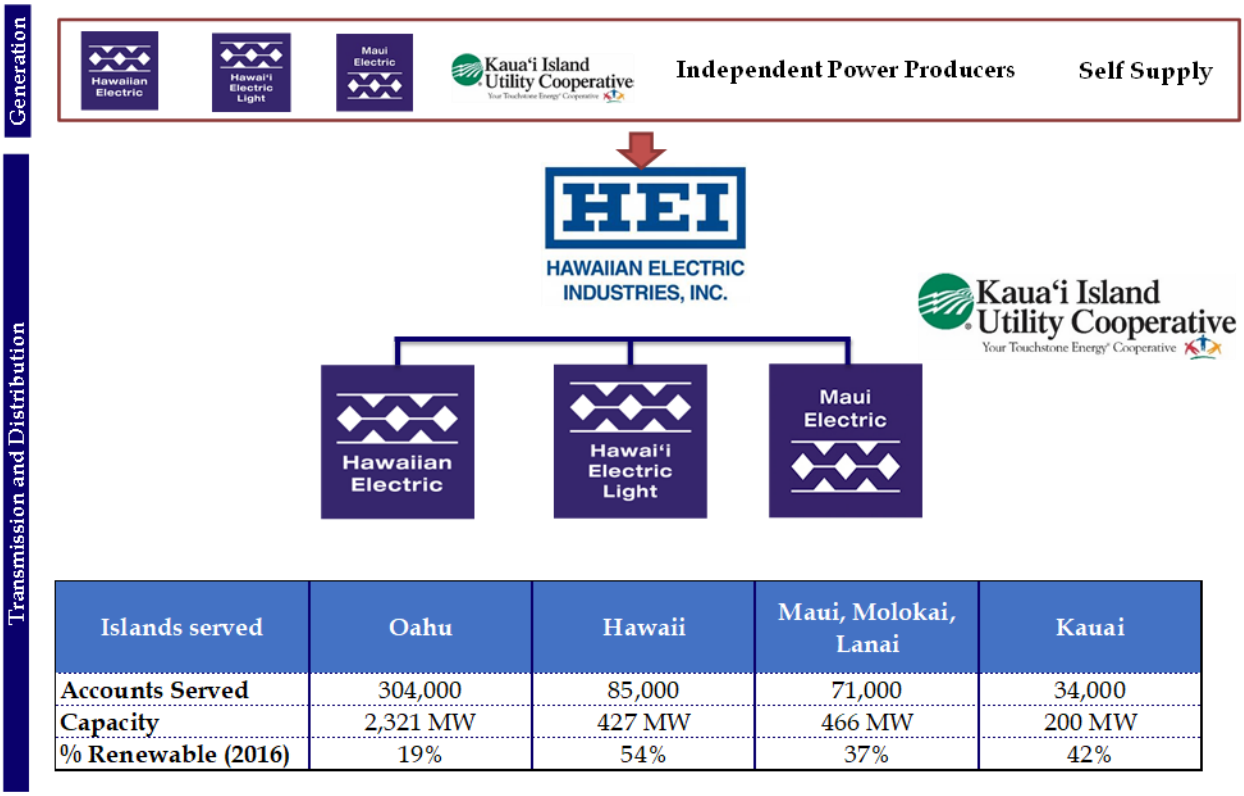
Hawaii's electricity sector consists of two vertically integrated utilities, namely the HECO Companies and KIUC. Vertically integrated refers to the utility's organizational structure which encompasses generation, transmission, and distribution. The same entity, without significant internal separation, is also responsible for system planning, maintaining reliability, coordinating dispatch and grid operations, and ensuring that there is adequate supply of energy, whether by providing energy and capacity itself or by contracting supply from independent power producers ("IPPs"). Figure 3 shows how HECO Companies and KIUC are currently structured.

Figure 3. Vertically integrated structure



The HECO Companies, which collectively form an IOU, are serving Hawaii, Maui, and Honolulu counties through their subsidiaries, Hawaii Electric Light Company ("HELCO"), Maui Electric Company ("MECO"), and Hawaii Electric Company ("HECO"). KIUC, which is the other vertically integrated utility in the state, is an electric cooperative ("co-op") and serves Kauai county. The utilities own a majority of the generation capacity in their respective service areas in addition to transmission and distribution assets. The remaining generation comes from IPPs and distributed generation (predominantly rooftop solar). The Hawaii Public Utilities Commission ("PUC") regulates the HECO Companies as well as KIUC, setting guidelines on operational requirements as well as rates and tariffs. Figure 4 shows a graphic representation of the electricity structure in the state.

Figure 4. Hawaii's electricity structure



Islands served	Oahu	Hawaii	Maui, Molokai, Lanai	Kauai
Accounts Served	304,000	85,000	71,000	34,000
Capacity	2,321 MW	427 MW	466 MW	200 MW
% Renewable (2016)	19%	54%	37%	42%

Source: HECO Companies' Power Supply Improvement Plan ("PSIP") Updated Report; HECO RPS Report 2016; KIUC website.

3.1.1 Hawaii county

HELCO owns all of the transmission and distribution ("T&D") assets and 58% of generation capacity in Hawaii county. Transmission lines with voltage levels of 13.8 kV, 34.5 kV, 69 kV, and 138 kV connect bulk generation to transmission and distribution substations. In total, there are about 622 miles of transmission lines and 74 substations – 10 transmission, 5 transmission & distribution, and 59 distribution.[8] HELCO has deployed Supervisory Control and Data Acquisition ("SCADA") systems at 78% of its distribution substation transformers.[9] As discussed in more detail in Task 1.1.3, Hawaii county has 427 MW of generation capacity, of which 57% is oil-fired and 24% is solar generation, including estimated distributed solar capacity.

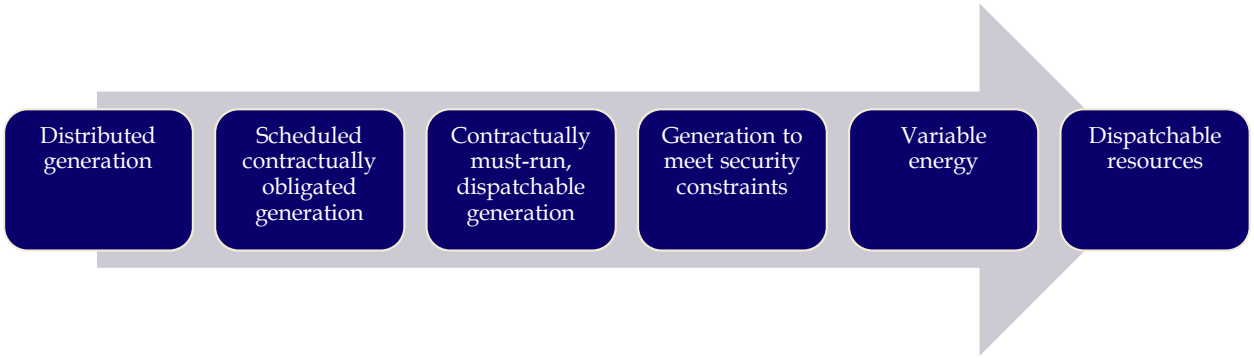
HELCO also functions as the system operator of Hawaii county's grid, using a centralized Energy Management System ("EMS") which provides real-time updates about the system. Dispatch is conducted with due consideration of safety, reliability, costs, and contractual and regulatory

[8] Annual Financial Reports ("AFR") for Electric Utilities 2016. Additional detail in the Excel spreadsheet deliverable for Task 1.1.3

[9] Hawai'i Electric, Maui Electric, and Hawai'i Electric Light ("HECO Companies"). *Modernizing Hawaii's Grid for Our Customers*. page 85. August 29, 2017.

compliance, including load duration. Dispatchable resources are placed under Automatic Generation Control ("AGC"). The order of preference for dispatch is shown in Figure 5.[10]

Figure 5. Dispatch Order of Preference



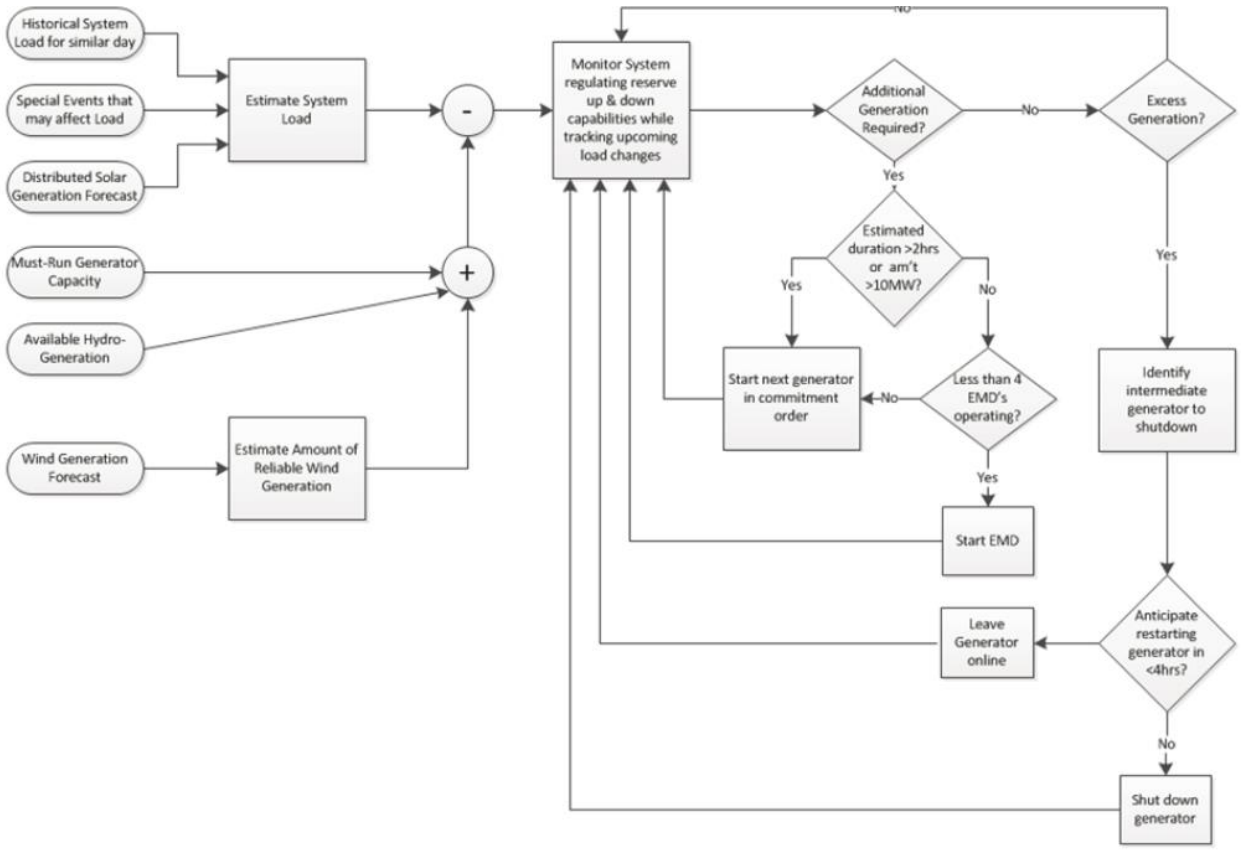
1. **Distributed generation**: for the most part, they are outside the utility's current control;
2. **Scheduled contractually obligated generation**: by contract, they are dispatched ahead of other resources regardless of economic merit;
3. **Contractually must-run, dispatchable generation**: they cannot be cycled offline, so the minimum dispatch level of these resources is accepted regardless of cost;
4. **Generation to meet security constraints**: they provide energy at their minimum dispatch level plus an amount of reserve capability;
5. **Variable energy**: non-dispatchable resources whose output fluctuates due to factors beyond control (like wind and solar) are accepted regardless of cost unless there is excess energy due to low demand, in which case these resources will be curtailed through a pre-established process and priority order; and
6. **Dispatchable resources**: they provide energy with a priority order of lower variable costs, or incremental costs if resources are already online.

Once the system load is estimated using historical load data and solar generation forecast, the system operator initially relies on resources like must-run generation and variable output from renewables to meet the load. If the load is not sufficient to support all of these resources, variable generation is curtailed. Otherwise, the operator dispatches additional capacity based on the expected size and duration of the additional load. Figure 6 shows the generation dispatch process. The HECO Companies provide system data on net energy system load, gross system load, solar irradiance data, and wind power production through REWatch, a website that is refreshed every 15 minutes.[11]

[10] *PSIP Update Report*. Book 3, page M-43 – M-44. December 23, 2016.

[11] Hawai'i Electric, Maui Electric, and Hawai'i Electric Light ("HECO Companies"). *PSIP Update Report*. Book 3, page M-46. December 23, 2016.

Figure 6. Generation Dispatch Process



Source: PSIP Update Report. Book 3, page M-39. December 23, 2016.

3.1.2 Maui county

MECO provides electric utility service in Maui, Lanai, and Molokai islands. It owns all the T&D assets in Maui County and 59% of generation capacity. The electric grids on the three islands in MECO service area are not connected. There are no 138 kV transmission lines in Maui county; instead, 258 miles of 23 kV, 34.5 kV, and 69 kV transmission lines connect bulk generation to 89 substations – 85 transmission and 4 distribution.[12] All of the transmission lines are on Maui island; Molokai and Lanai have small systems with distribution lines only. MECO has deployed SCADA systems at 33% of its distribution substation transformers.[13] As discussed in more detail in Task 1.1.3, Maui County has 466 MW of generation capacity, of which 59% is oil-fired, 15% is wind, and 26% is solar generation, including estimated distributed solar capacity.[14]

[12] AFR 2016. Additional detail in the Excel spreadsheet deliverable for Task 1.1.3

[13] *Modernizing Hawaii's Grid for Our Customers*. August 29, 2017. Page 85.

[14] Maui County also has hydro, which comprises 0.1% of installed capacity.

MECO's dispatch process is the same as HELCO's, but only Maui island has AGC capability. Molokai and Lanai rely on isochronous control units for frequency regulation.[15]

3.1.3 The City and County of Honolulu

The City and County of Honolulu, which includes the island of Oahu and the state's capital and largest city, Honolulu, is served by HECO. It owns all of the T&D assets in The City and County of Honolulu and 51% of generation capacity. The City and County of Honolulu has mostly 138 kV transmission lines (with two 46 kV lines). In total, there are about 817 miles of transmission lines and 143 substations – 42 transmission and 101 distribution.[16] HECO has deployed SCADA systems at 49% of its distribution substation transformers.[17] As discussed in more detail in Task 1.1.3, The City and County of Honolulu has 2,321 MW of generation capacity, of which 57% is oil-fired and 23% is solar generation, including estimated distributed solar capacity.

HECO follows the same dispatch process as HELCO.

3.1.4 Kauai county

KIUC is a co-op, which means it is a non-profit organization owned and controlled by its member-customers. KIUC was founded in 1999 and purchased Kauai Electric Company, an IOU serving Kauai island, in November 2002. Today it has 24,745 active member-owners who have received a total of $26 million in patronage capital and refunds since its setup.[18] It has considered increased exemption from PUC regulation for greater operational flexibility.[19]

KIUC's electric grid consists of 171 miles of 58 kV transmission lines and over 1,200 miles of 12.47 kV distribution lines as well as 26 substations – 5 transmission and 21 distribution.[20] KIUC also deployed 28,000 smart meters in 2013, allowing its customers to track their energy use and pay their bills on its online customer information system.[21] As discussed in more detail in Task 1.1.3, Kauai county has 200 MW of generation capacity, of which 58% is oil-fired and 33% is solar generation, including estimated distributed solar capacity. However, the use of renewables is

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[15] *PSIP Update Report*. Book 3. December 23, 2016. Page M-41.

[16] AFR 2016. Additional detail in the Excel spreadsheet deliverable for Task 1.1.3.

[17] *Modernizing Hawaii's Grid for Our Customers*. August 29, 2017. page 85.

[18] KIUC website.

[19] Kauai Island Utility Cooperative. *2016 Annual Report*. Page 7.

[20] AFR 2016; KIUC. *Currents*. page 8. June 2017.

[21] Kauai Island Utility Cooperative. *2016 Annual Report*.

growing rapidly. The utility manages dispatch with an EMS/SCADA system, which it proposed to upgrade in 2018.[22]

[22] Kauai Island Utility Cooperative. *2017 Capital Improvements Program for Ensuing Five Years*. December 27, 2016. Page 2.

4 Future infrastructure needs

As is the case in many jurisdictions in the United States, Hawaii's electricity grid has several aging components that need to be upgraded or replaced in transmission and distribution, as well as generation. The nature of the grid's function is also changing, as many customers want the ability to both produce and consume energy. The high penetration of DERs, an estimated 80,000 privately owned rooftop solar systems in the HECO Companies' service areas and over 2,500 in Kauai, will continue to grow as system costs fall. [23, 24] Economic considerations and the state's Renewable Portfolio Standards ("RPS") law means that utility-scale generation will increasingly be based on renewable and variable resources like wind and solar and backed by storage. The anticipated growth in use of electric vehicles ("EVs") will also alter the dynamics of energy flows on the grid.

This transition will necessitate significant investment to improve grid infrastructure, reliability, operational flexibility, and customer experience. Utilities must develop various capabilities to manage the challenges of integrating DERs. Quantifying the locational values of distributed generation ("DG") will help inform incentives that encourage development of DGs in places where they provide more benefit to the system. EVs present an opportunity to increase sales, as long as there are investments in charging station infrastructure and rate reform to account for new supply- and demand-side resources such as EVs, DERs, etc. Likewise, energy storage technologies can help utilities in their planning process for a grid with high penetration of intermittent renewables and DERs because they offer flexibility through frequency regulation and ramping support. Energy efficiency is more effective with established standards and ability to target energy conscious customers with more sophisticated data collection and segmentation abilities. Third-party actors can help boost demand response ("DR") as independent aggregators. Digitalization will increasingly be the standard whether in customer experience or utility operations, which will require additional data centers, software systems and cybersecurity infrastructure.[25]

In the Power Supply Improvement Plan ("PSIP") and Modernizing Hawaii's Grid for Our Customers (Grid Modernization document), the HECO Companies have laid out their plan to upgrade the electricity system in their service areas in some detail, including estimated costs. [26, 27] As shown in Figure 7, the upgrade involves adding nearly 1 GW of new renewable and demand response capacity. This is about half of the existing coal- or oil-fired generation capacity in the HECO Companies' service areas. About half of the new capacity will come from utility-scale solar and wind, but distributed solar is also projected to grow significantly to provide a third of

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[23] *Modernizing Hawaii's Grid for Our Customers*. August 29, 2017. Page ES-1.

[24] KIUC website.

[25] World Economic Forum. *The Future of Electricity – New Technologies Transforming the Grid Edge*. March 10, 2017. Page 20-22.

[26] *PSIP Update Report*. Book 1. December 23, 2016. Page 5-5 – 5-27.

[27] *Modernizing Hawaii's Grid for Our Customers*. August 29, 2017. page 107-111.

incremental renewable capacity over the next five years. Figure 8 shows that the HECO Companies expect customer-sited resources to continue growing by several-fold beyond the next five years through to 2045. In particular, the growth of storage and demand response resources will help the utilities to manage a grid with high renewable penetration more effectively.

Figure 7. Capacity additions: renewable energy and demand response (DR) – 2017-2021

Utility	Island	DG-PV (MW)	FIT (MW)	DR (MW)	Grid-scale PV (MW)	Grid-scale wind (MW)
HECO	Oahu	255.1	23.8	88.8	352.2	64.0
MECO	Maui	38.4	1.0	14.7	6.7	62.0
MECO	Molokai	1.4	0.0	0.3	0.0	5.0
MECO	Lanai	0.7	0.0	0.3	0.0	4.0
HELCO	Hawaii	30.3	5.7	10.6	1.0	22.0
		325.9	**30.5**	**114.7**	**359.9**	**157.0**

Source: PSIP Update Report. Book 1. December 23, 2016. Page ES-3.

Figure 8. PSIP Projections - DERs and DRs

December 2016 PSIP Projections	2017-2021	2022-2045
New DG-PV	326 MW	2,086 MW
New Customer Self-Supply (CSS) Energy Storage	89 MWh	1,057 MWh
New Demand Response Capacity	115 MW	442 MW
New Demand Response Energy Storage	104 MWh	1,608 MWh

Source: Modernizing Hawaii's Grid for Our Customers. August 29, 2017. Page ES-1.

In addition to the capacity additions laid out in Figure 7 and Figure 8 which are necessary to achieve the state's clean energy goals, the Grid Modernization document recognizes that the utilities will need to develop capability for distribution level functions, such as: load and DER forecasting, streamlined DER interconnection procedures, hosting capacity information for DER providers, locational value analysis, integrated resource and T&D planning, physical coordination of DER operations, sourcing of energy, ancillary and grid services, distribution and bulk power system services, DER services settlement, and program facilitation.[28] However, due to the much higher penetration levels of distributed solar in Hawaii compared to New York or even California, the HECO companies anticipate fewer opportunities for DER investments to be used as a means to defer capital expenditure at a distribution level.

KIUC's plans also indicate its strategic direction without providing as much detail. The utility plans to generate at least 70% of electricity from renewables by 2030, but by limiting incremental renewable generation in a year to no more than 20% of Kauai's load in that year.[29] This approach

[28] *Modernizing Hawaii's Grid for Our Customers*. August 29, 2017. Page 30.

[29] KIUC. *Strategic Plan Update 2016-2030.* January 2017. Page 5.

allows it to manage technology and price risks and therefore control cost increases wherever possible. In an interview with ThinkTech Hawaii, the CEO of KIUC, David Bissell, suggests that their focus in Kauai for now is more on utility-scale solar and storage rather than on growing distributed solar on rooftops because utility-scale is 2- to 2.5-times cheaper and more readily deployable.[30] KIUC will soon seek rate reform to encourage usage when costs are low, and to improve its financial stability by increasing the emphasis on fixed rather than volumetric charges.[31] It also intends to spend over $52 million in recurring and $56 million in non-recurring expenses between 2017 and 2021.[32] The non-recurring expenses include proposed projects like a new control/dispatch center and upgrades to the SCADA system, the GIS mapping system, and generation infrastructure.

Maintaining smooth functioning of an electric grid with 100% renewables generation requires deployment of many different types of technologies or infrastructure at various levels. HECO Companies enumerated some of these needed technologies in the Grid Modernization document.[33]

1. **Advanced Operational Systems** – distribution operations center ("DOC"), distribution management system ("DMS"), distributed energy resource management system ("DERMS"), outage management system ("OMS"), geographic information system ("GIS"), and situational awareness;

2. **Distribution System Components** – advanced meters, fault circuit indicators ("FCI"), remote intelligent switches, secondary var controllers ("SVC"), and substation automation;

3. **Network Components** – wide area network, field area network, and neighborhood area network; and

4. **Customer Assets** – advanced inverters.

As Figure 9 shows, the HECO Companies will need substantial investments across these technologies in the next few years. The customer-oriented technologies and interfaces allow customers greater insight into their energy usage and therefore greater control over their energy bills. If customers have access to their usage data, they can make better-informed decisions on selecting, sizing, and financing DERs like energy efficiency, rooftop solar, or storage. Utilities can also leverage these technologies to simply notify the customers about their service and engage customer participation in grid management services through energy efficiency, demand response, and customer-sited energy storage programs. As the EV market grows in Hawaii,

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[30] Bissell, David. *On Kauai, the Future is Now with KIUC*. ThinkTech Hawaii, February 16, 2017. Interview. Accessed October 19, 2017.

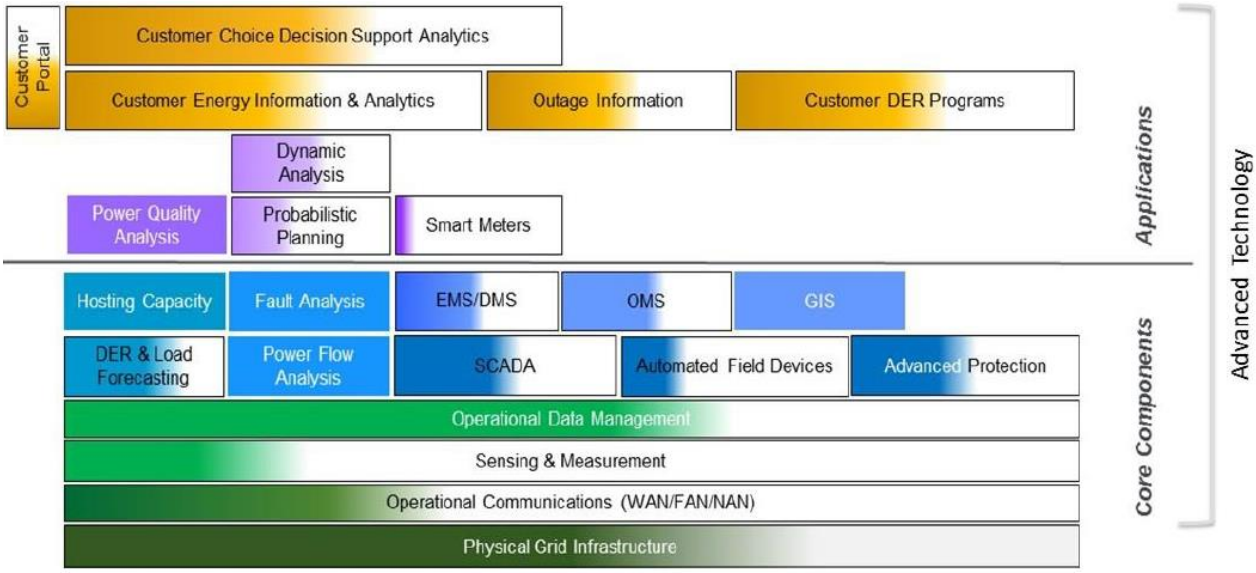
[31] Kauai Island Utility Cooperative. *Strategic Plan Update: 2016-2030*. January 31, 2017. Page 5.

[32] *2017 Capital Improvements Program for Ensuing Five Years*. Appendix 1. December 27, 2016.

[33] *Modernizing Hawaii's Grid for Our Customers*. p 79-80.

customer-facing technologies are also important to inform programs that promote EV sales while managing the grid so that the additional load benefits the system. At the same time, grid-facing technologies are also necessary to increase the utilities' visibility into the distribution system and responsiveness to any operational issues. They would help to manage two-way energy flows and prevent overloads. Different technologies can interface with each other, making the system more automated and efficient.

Figure 9. Current status of HECO Companies' customer-facing and advanced grid technologies



Source: Modernizing Hawaii's Grid for Our Customers. August 29, 2017. Page 50.

The HECO Companies have divided their planned infrastructure expenditure in four different categories based on the purpose of the expenditure:[34]

1. **Standards and safety compliance** – grid expenditures required to maintain safe and reliable operations. This includes investments to replace aging or failing infrastructure as well as grid modernization technologies pertaining to grid sensing and measurement, telecommunications, and automation control. They are required to meet reliability and service quality standards, especially with increasing DER use. In the future, operational reliability will be ensured using different methods than present, which will require different technologies and capabilities, as shown in Figure 9.

2. **Policy compliance** – investments in customer- or merchant-adopted DER needed to comply with state policy goals or regulatory directives.

[34] Ibid. Page 42-43.

3. **Net benefits** – expenditures that would provide a positive net benefit for customers. These investments would enable DER aggregators as well as provide grid services that help to manage the power system more cost-effectively.

4. **Self-supporting** – expenses where the costs are assigned to the specific customer for whom they are incurred. These investments are also driven by the needs and requests of that customer or group of customers. For example, the associated infrastructure necessary with customer adoption of EVs would fall in this category.

Figure 10. Technical Strategies for Operational Reliability

Issue	Current Methods	Future Methods
Frequency Support	■ Inertia is the stored rotating energy in a power system provided by online synchronous and induction generation operating at least their minimum power output level. ■ Primary frequency response (droop) is the automatic corrective response of the system, typically provided by synchronous generation, to react or respond to a change in system frequency. ■ Spinning reserve is typically provided by synchronous generation that is ready to ramp up or down in response to a frequency deviation. ■ Demand response is the reduction of load to balance loss of generation triggered at a predetermined frequency set point and limited by program participants. ■ Under frequency load shed scheme is the automatic disconnection of blocks of load to re-balance the system during a frequency disturbance.	■ Synchronous condensers and flywheels to provide inertia ■ Fast frequency response resources such as batteries, flywheels, curtailed PV and wind energy that can respond in cycles, upwards, by injecting energy into the grid. ■ Demand Response resources (with fast frequency response characteristics) that can respond within a specified time adequate to correct frequency imbalances. This can be reductions in load or injection of real power from DER aggregated into a controllable and quantifiable program to respond to under frequency events, or a fast injection of controllable load in response to an over-frequency event. ■ Autonomous downward response of inverter based DER resources configured with the advanced inverter frequency-watt function to respond to an over-frequency event.
Voltage Support/Short Circuit Availability	■ Reactive power supply and voltage control provided by synchronous generating facilities, excitation systems, and capacitors. ■ Protective relay schemes designed to isolate faults within cycles. ■ Fault current supplied by synchronous generators. ■ Dynamic reactive power capability of synchronous generators and static var compensators.	■ Synchronous condensers to provide reactive power support and short circuit current. Repurposing de-activated generators as condensers. ■ Storage systems such as battery storage, electric vehicles, flywheels, and thermal storage to provide quick and flexible energy sources to stabilize system balancing.

Source: PSIP Update Report. Book 1, Table 2-2. December 23, 2016. Page 2-21.

According to the HECO Companies' projections, the capital expenditures between 2017 and 2021 will be about $295 million for power supply and $91 million for smart grid investments.[35] According to the Grid Modernization document, there will be an estimated $205 million in investments in new technologies and software between 2018 and 2023; the resulting increase in customer bills will be $0.94/month, $2.07/month, and $1.93/month in Honolulu, Hawaii, and Maui counties, respectively.[36]

Many of these investments will be needed to modernize the grid infrastructure to help grid services be more flexible and reliable, while encouraging greater deployment of renewables and DERs; this will be true regardless of the utility ownership and regulatory models. In some instances, moving to a different ownership structure such as a co-op or muni, may not require additional investments; in others, it will require more investments in certain types of infrastructure or in creating new organizational units and facilities.

4.1 Moving to a co-op

The co-op model does not require any additional infrastructure for transition from the current IOU (for the HECO Companies) to a co-op. After the co-op purchases the assets, it will provide the planning, investments, and operations functions currently carried out by the HECO Companies. Kauai transitioned from an IOU to a co-op when KIUC purchased all the physical utility assets in service owned by Kauai Electric. Since it assumed the role of the utility that had been filled before by Kauai Electric, there was no need for additional infrastructure investments. In fact, KIUC was required to notify the Hawaii PUC and the Consumer Advocate about significant intended investments as one of the terms of the PUC's approval.[37]

4.2 Moving to a municipal utility

Like the co-op, a change in the ownership model from an IOU or a co-op to a muni would simply represent change in ownership and management oversight. There are no additional infrastructure investments needed since the current infrastructure is already in place to be able to operate the power system.

4.3 Moving to a Single Buyer

As discussed in Task 1.1.1, the Single Buyer ("SB") can be set up with different structures. The SB can be:

- a stand-alone not-for-profit entity (Figure 11);
- a part of an independent system operator ("ISO") (Figure 12); or
- a role that the utility itself carries out (Figure 13).

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[35] *PSIP Update Report*. Book 1. December 23, 2016. Page 5-5.

[36] *Modernizing Hawaii's Grid for Our Customers*. August 29, 2017. Page 110.

[37] Filsinger Energy Partners. *Evaluation of Alternative Ownership Options for Electric Utility Assets on the Islands of Oahu and Hawaii. Subtask 4.2: Economic Analysis*. April 2016. Page 36.

An example of an independent SB is the Ontario Power Authority ("OPA") in Canada, before it merged with the Independent Electricity System Operator on January 1, 2015. The OPA was responsible for evaluating the long-term adequacy of electricity resources in Ontario, projecting the future demand and potential for conservation and renewable energy, preparing an integrated system plan, procuring new supply either by competition or by contract, and meeting the targets set by the government for conservation and renewable energy.[38]

On the other hand, in Brazil, the SB does not buy and sell electricity but simply coordinates the central auction, and the contracts are between generators and distributors.[39]

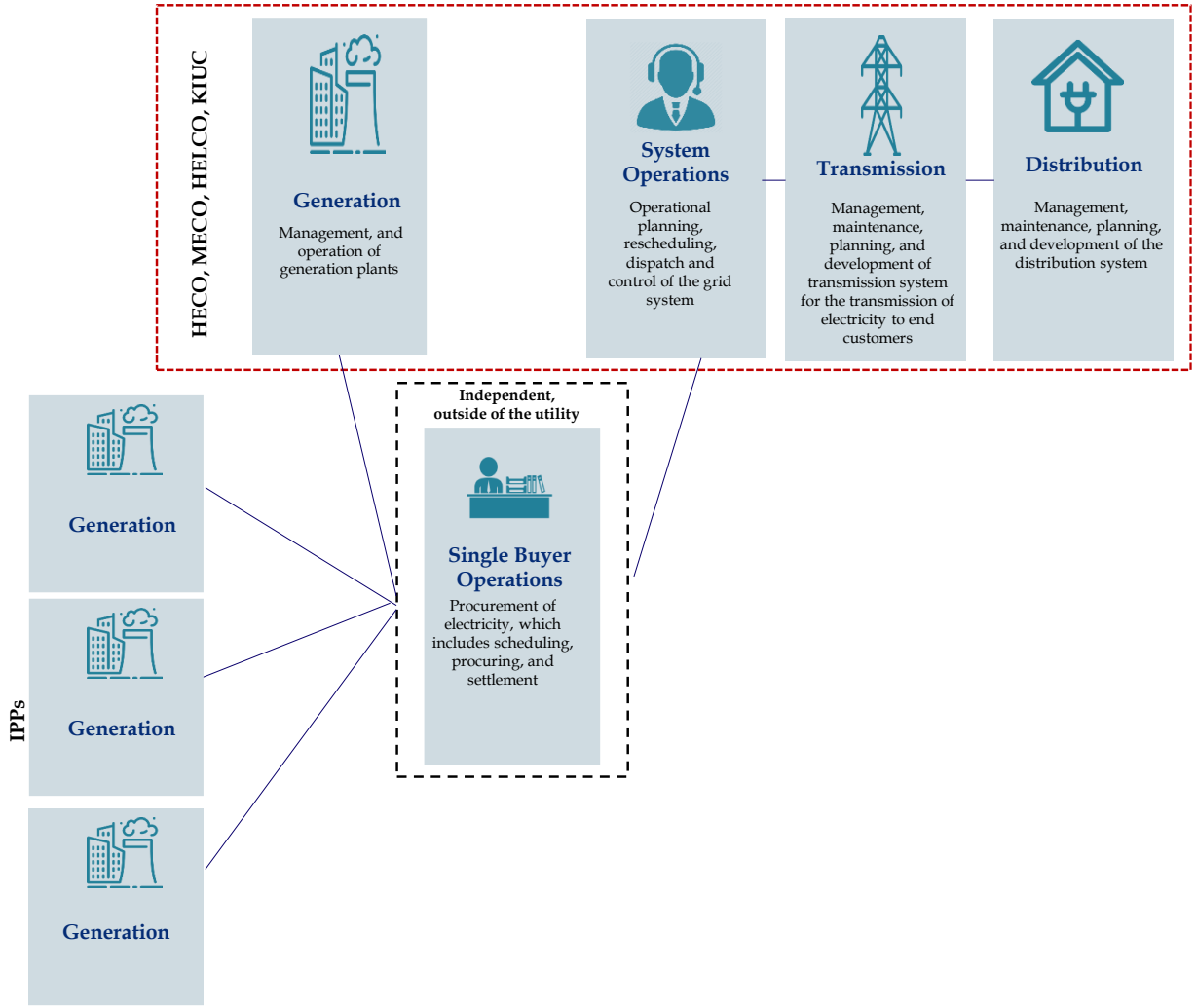
Single Buyer model in Brazil

Brazil has a modified SB model which reflects its past experiences in restructuring electricity markets. In the 1990s, the country moved from vertically integrated public utilities to a system where distribution companies could negotiate energy supply contracts with generators on the spot market but had to purchase at least 85% of their energy through wholesale contracts of at least two years' duration. This structure did not provide sufficient incentive to invest in new generation capacity and, as a result, there were massive electricity shortages. This crisis led to the current structure. The single buyer runs regulated auctions for customers who consume less than 3 MW – distribution companies contract supply from generation companies. There are also adjustment auctions which allow distributors to revise their contracted positions if their forecasts are wrong.

[38] Electricity Restructuring Act, 2004. S.O. 2004, c. 23 – Bill 100.

[39] Castalia. *International Experience with Single Buyer Models for Electricity: Report to Contact Energy.* August 2013. Page 13.

Figure 11. Single Buyer is independent and outside of the utility

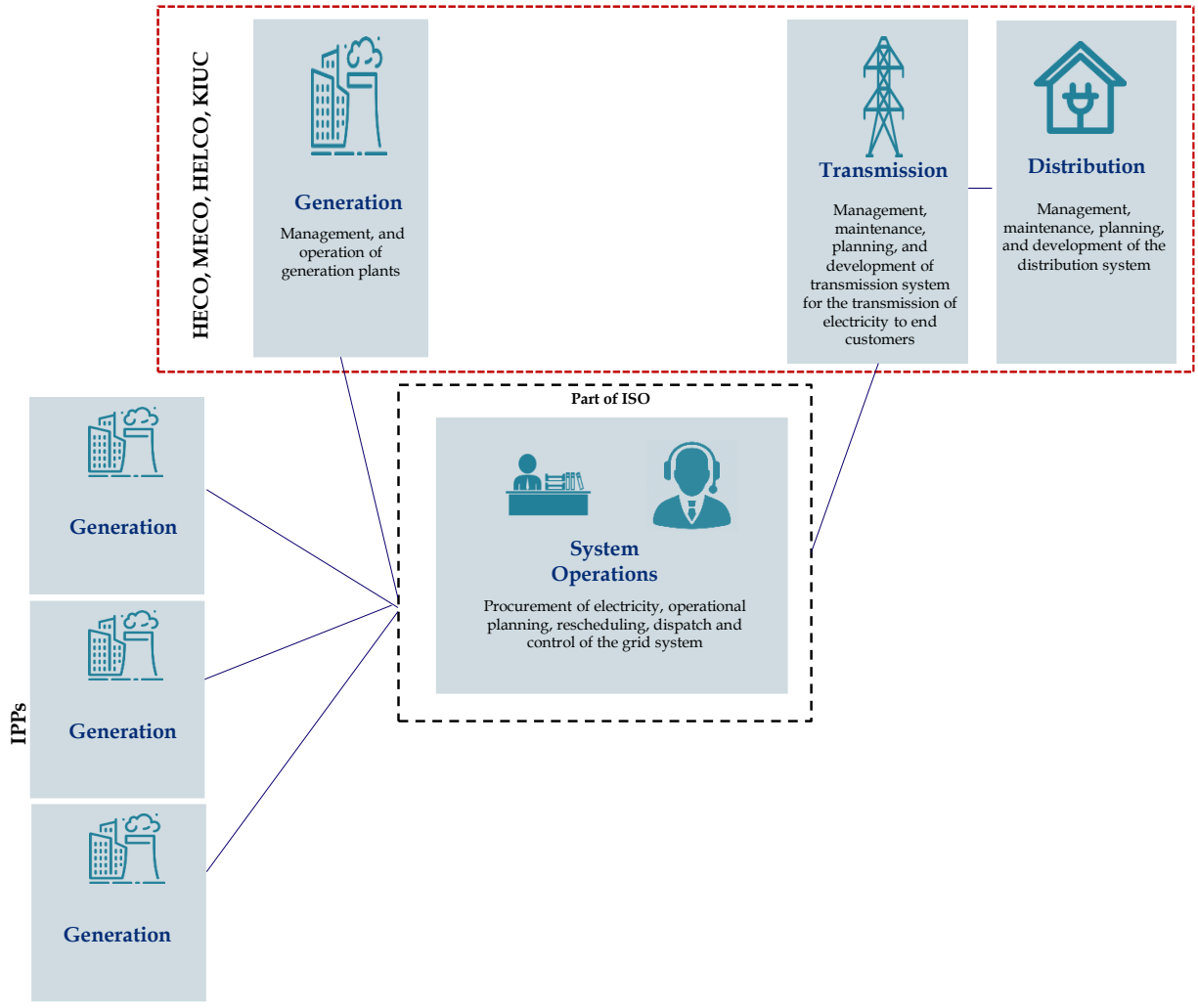


In the third variant of the model, the utility would still be allowed to bid its own projects into SB procurements as long as the SB is ring-fenced. The primary purpose of ring-fencing is to limit the ability of the SB to confer an unfair advantage to its affiliated entity. The SB itself would not own any generation or wires assets but serves as an independent resource planning and procuring body. All generation and DERs would need a contract with the SB to interconnect to the grid. An example of a SB that is still part of the utility is the Tenaga Nasional Berhad ("TNB") in Malaysia. The textbox below provides a brief background about TNB's SB ring-fencing mechanisms.

Transitioning to a SB model will necessitate the creation of a separate organization with its own office workspace and accompanying set up. This is true whether the SB is an independent organization from the utility or a ring-fenced business unit within the utility itself. Ring-fencing involves separating both operations and accounts from the parent company (in this case, the utility), including staffing, accounts, financial reporting, information technology ("IT"), and

compliance reporting.[40] The regulatory body must also develop additional capability to monitor compliance with obligations from ring-fencing such as non-discrimination, limits on information sharing, and to oversee dispute resolution.

Figure 12. Single Buyer is part of an ISO

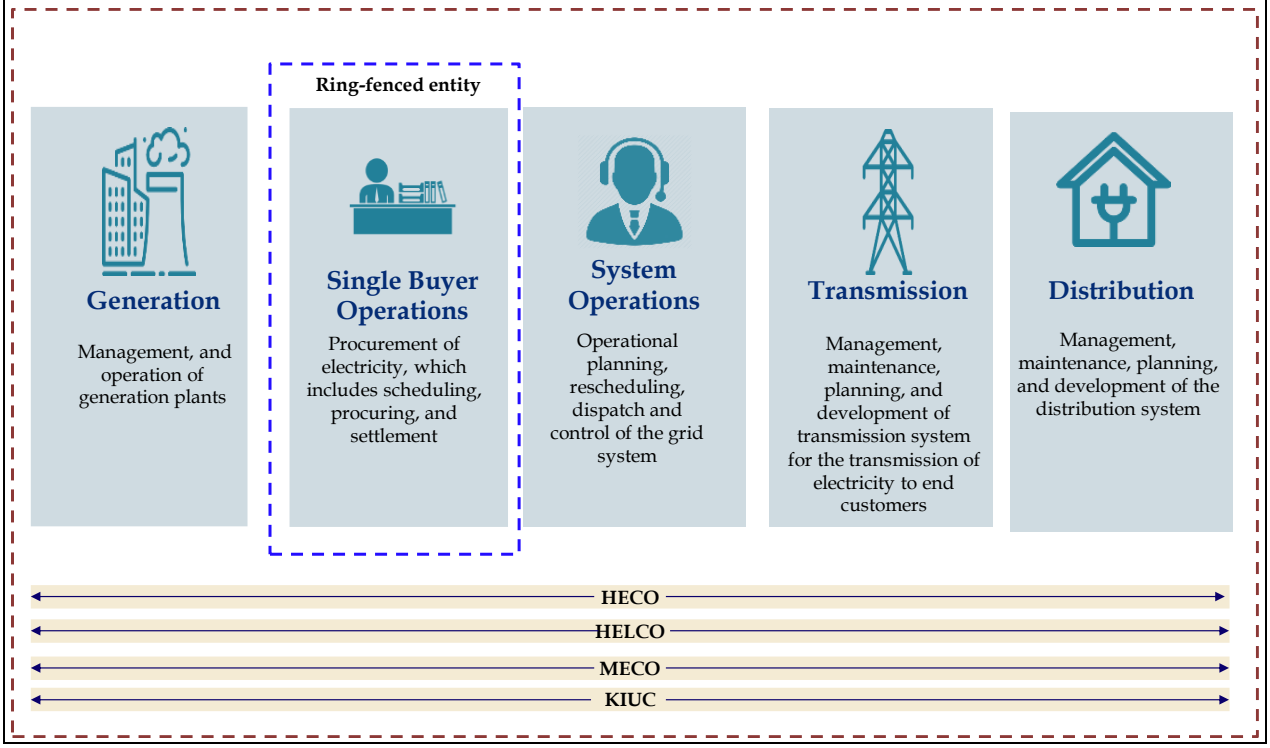


The SB will need the necessary infrastructure, technology, capability, and authorization to conduct the resource planning function. It must be able to forecast load and generation and process information about system constraints in real time, all of which will feed into dispatch control. These operations will require a greater degree of sophistication as the penetration of customer-sited DERs and variable utility-scale generation increases. These capabilities can be sourced from the utility itself because the SB will be taking over the resource planning functions from the utility. The utility may want to retain some forecasting and resource planning

[40] Suruhanjaya Tenaga – Energy Commission. *Single Buyer Rules – version 2.0.* January 2015. Page 35-37.

capabilities for its own operations, especially on the T&D side, in which case these functions would be partially duplicated in the SB.

Figure 13. Single Buyer is still part of the utility but ring-fenced



Under the capacity procurement responsibility, the SB is responsible for ensuring that there is enough capacity to meet system needs. Capacity could be sourced from utility-scale generation, from either the utility or IPPs or DERs. It will identify the characteristics of the resource needed to meet certain system needs and then run competitive tenders and auctions for resources that meet those criteria. The SB then enters into contracts with the winners. Thus, the SB must be proficient in identifying the types of resources needed, designing tenders to maximize cost savings, and contract management. Since the SB will procure capacity at long-run least cost and is neutral regarding the capacity provider, there may be additional opportunities under this model to save utility investments in generation capacity if either IPPs or DERs can provide them at lower cost.

As the market operator, the SB must also maintain transparency in its operations. The market participants (capacity providers) must have equal access to information about tendering and system needs through something like an online information portal. The portal can be used to provide system data to market participants to inform their bidding, as well as to conduct tenders and publish their results.

Single Buyer example: Tenaga Nasional Berhad

TNB is Malaysia's sole electric utility company. It was formed in 1990 as a government-owned corporation. In the 1990s, it was a vertically integrated utility, and owned the majority of generation, in addition to T&D. IPPs provided some competition in generation. TNB also conducted energy procurement from the IPPs. However, further reforms in the Malaysian Electricity Supply Industry ("MESI") led to the creation of the Single Buyer ("SB") in 2012, a ring-fenced entity within TNB. The role of TNB's Single Buyer includes the following:

TNB's Grid System Operator and Single Buyer are both ring-fenced from the other business entities of TNB. Below are some of the ring-fencing measures imposed within the company.

Item	Grid System Operator ("GSO")	Single Buyer
Work area	Separate from the work areas of other divisions and units within TNB	Separate from the work areas of other divisions and units within TNB
Sharing of information	The ownership of all data in the principal operational systems used by GSO, all other data jointly by the GSO and Single buyer, and the data held in corporate or shared administrative system relating to GSO' operation or staff, shall be rest with GSO GSO shall not disclose any information that is confidential to TNB or any other party	The Single Buyer shall not disclose any information that is confidential to TNB or any other party, or information that may provide competitive advantages to any other party
Accounts	Needs to maintain a separate set of Financial Statutory Accounts, which is audited at least annually and published on the GSO's website	A separate set of Single Buyer Accounts relating to the performance of its functions as a Single Buyer should be maintained and established
Access to IT system	1) Only GSO staff can access systems that are only used by the GSO; 2) 2) shared systems are partitioned so that staff of other divisions only have information that they require in their performance and that won't provide them with competitive advantages; 3) 3) a record is maintained of the date and time that each information item is accessed and/or changed by each user of GSO's IT system.	Other users of the IT system cannot access confidential information held by the Single Buyer
Compliance report	Prepare a statement of compliance, and the GSO shall identify a full-time "Compliance Officer" who manages the compliance arrangements	Prepare a statement of compliance, issue guidelines, and provide supporting information to justify compliance

Sources: Tenaga Nasional Berhad website, Electricity Tariff Regulation Implementation Guidelines

The additional infrastructure needs under an SB model relative to the status quo is primarily related to the office facilities of the SB, including the computers and software necessary for its planning and procurement functions. The capital expenses of Ontario Power Authority ("OPA") in 2005, the year in which it began operations, are shown in Figure 14 below. These costs are incurred periodically to replace these assets at the end of their useful life. The computers and

software used specifically for planning must be replaced with more sophisticated versions as penetration of DERs and renewables increases.

Figure 14. Ontario Power Authority - SB Capex

	Cost (2005 CAD)	Asset Life (years)	Cost ($000s, 2016 USD)
Furniture and equipment	1,174,275	10	1,431
Leasehold improvements	1,458,998	Length of lease	1,779
Computer hardware and software	693,839	2.5	846
Audio visual equipment	135,843	10	166
Telephone system	49,217	5	60
Total	3,512,172		4,281

Note: FX conversion to 2005 USD (1 USD = 1.02 CAD); adjusted for inflation at 2%.

Source: Ontario Power Authority. 2005 Annual Report.

The estimates of capital expenses to establish an SB for each county in Hawaii are derived in Task 1.4.2. These costs may be partially offset by moving the current utility's assets to the SB.

4.4 Moving to an integrated DER

The integrated distributed energy resources ("IDER") system operator is an innovation in the utility business model. Currently, there is no jurisdiction that has an IDER system operator. However, a transition to this model is currently underway in New York state through several regulatory proceedings under the Reforming the Energy Vision ("REV") framework. Under this model, the utility would have to divest from its generation business and own just the distribution assets. A system operator, either an independent entity or the utility itself, would manage energy flows and execute transactions across the grid, including peer to peer relationships. The role of an IDER system operator in managing the distribution system is similar to how an ISO manages system planning and ensures reliable grid operations, but the IDER system operator is not directly involved in procuring sufficient energy or capacity. Distribution companies purchase wholesale energy from the bulk power system; at a distribution level, they can also buy energy from customers with DERs. Likewise, customers could transact with the distribution companies or each other. The IDER system operator just provides the platform and price signals for these transactions.

The New York Public Service Commission ("PSC") set the state's utilities towards this model through its Track One Order in which it defined the electric utility ecosystem under REV.[41] The future role of the utility is defined as a distributed system platform ("DSP") provider. DSP is the platform for a market in which customers and market actors interact with utility-scale generators and DERs. In the New York model, DERs are primarily owned by customers or third parties; utilities can only own DERs if the market cannot do so in a cost-effective manner. DERs will be

[41] State of New York Public Service Commission. Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. *Order Adopting Regulatory Policy Framework and Implementation Plan (Track One Order).* February 26, 2015.

part of system planning and operations, but utilities will own the wires portion of the business. The utility's/DSP's functions are:

1. ***Integrated system planning*** – analysis and planning for system needs to integrate DERs;

2. ***Reliable grid operations*** – ensuring safe and reliable service with integrated DERs; and

3. ***Market operations*** – determining pricing and market settlement for DERs.[42]

The PSC then issued its Track Two Order to align utility financial interest with that of the customers. It established that utilities can earn performance incentives for achieving REV objectives as well as revenue from products and services that facilitate DSP markets and fees from value added services.[43] The PSC also directed the utilities to file distributed system implementation plans ("DSIP"). Each utility filed a separate Initial DSIP outlining their current capabilities and planned investments in the near-term. The utilities then jointly filed a Supplemental DSIP as the Joint Utilities of New York ("JU") with the aim of working towards convergence in process and protocols so that the DSP markets across the utility service areas are more seamless. The immediate infrastructure needs, as identified by the JU, are similar to those laid out by the HECO Companies in the Grid Modernization document, and includes DMS, ADMS, Distribution Automation ("DA"), and DERMS. The JU recognizes the long-term objective of moving towards a DSP platform with associated markets, and see the near-term investments in grid modernization and DER integration as developing the necessary enabling infrastructure. The particular areas of interest that the JU identify are customer data, system data, DER sourcing, EV supply equipment, NYISO/DSP coordination, hosting capacity analyses, monitoring & control, and load/DER forecasting. The investments and structure identified by the HECO Companies in Figure 9 contain much of the underlying infrastructure needed for a DSP platform as laid out by the JU in To provide an idea of how much the infrastructure would cost, the Project Team looked at the utilities in New York, which have started making investments in some of the enabling technologies and pilot programs that would eventually lead to a fully-fledged DSP. Figure 17 shows some of the costs for preliminary phases of these projects. These costs may increase in the future and are not exhaustive. The five-year costs range between $11 and $190 million, depending on the technology, utility service area, and current status of utility infrastructure.

There are also pilot projects in New York for transactive energy systems. LO3 Energy, a startup in Brooklyn, has built a blockchain-based microgrid. The Brooklyn Microgrid project now has 60 energy-producing consumers, called "prosumers," and another 500 buyers participating in its market. The company builds both the software platform and accompanying hardware like high-resolution meters. While the costs of the project are not public, LO3 Energy raised $1.2 million from investors in March 2017, $6.3 million in October 2017, and an undisclosed amount from Siemens in December 2017. This blockchain-based microgrid currently augments the existing

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[42] REVConnect website.

[43] State of New York Public Service Commission. Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (Track Two Order).* May 19, 2016.

distribution grid, but it is an example of a market platform where customers can choose their source of energy and DER owners can sell directly to the buyers.

, like advanced meters, SCADA, DMS, customer-sited DERs, and advanced sensing equipment.

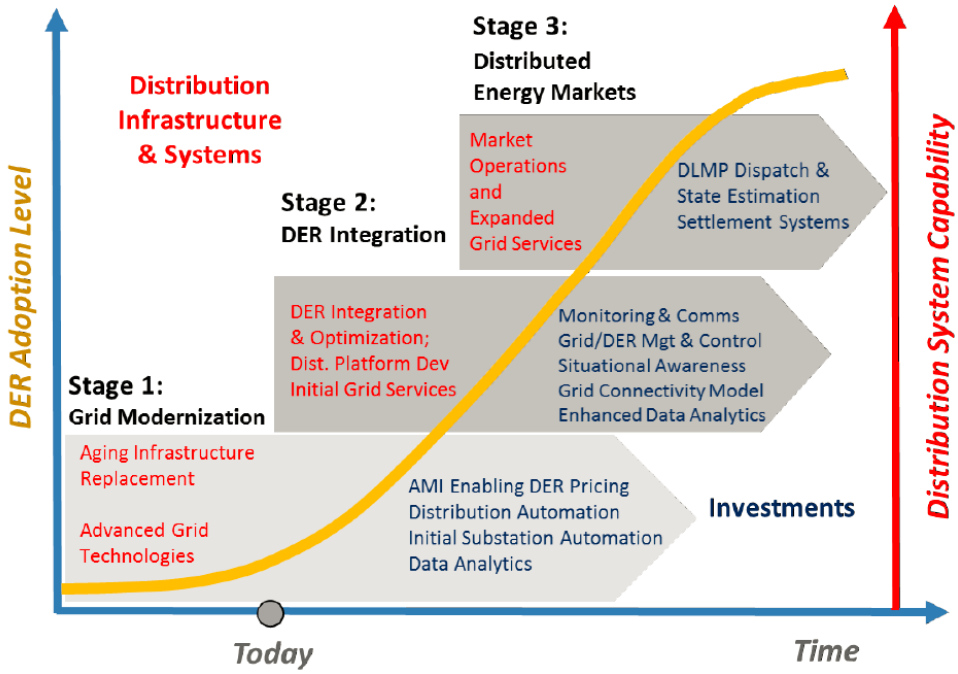
In an IDER model where the utility is the system operator, the utility would continue to own the T&D assets, but not the generation assets. This can be accomplished in several ways. One approach is for the utility to spin-off its generation assets into an unregulated subsidiary, with the regulated utility focused exclusively on the T&D side of the business. Another approach would be a mandated divestment of generation. The utility can potentially use some of the proceeds from divestment of its generation assets to invest in modernizing T&D infrastructure. However, a forced divestiture is likely to result in asset sale at a discount. This could in turn lower the credit rating of the utility and make it more difficult to raise capital.

An IDER system operation would require the use of new technologies like blockchain,[44] but that will only be possible once there have been significant upgrades to the existing grid. While the planned near-term investments in grid modernization are similar for the HECO Companies and the JU, there is a much greater emphasis in engaging market actors in New York. As for KIUC, the focus will be on increasing utility-scale renewable generation in the short-term. KIUC is ahead of its HEI counterparts in deploying DERs and smart meters, and it intends to deploy some new infrastructure that helps the utility continue to provide reliable services.

Since utilities will have greater interactions with customers and DER providers in an IDER model, New York has seen more movement in facilitating those interactions, e.g. by streamlining portals for interconnection applications and DER sourcing. In particular, the New York utilities have begun engagement with stakeholders in the types of data they can provide and the necessary cybersecurity infrastructure to protect that data. A move to an IDER model will most likely require more investments to facilitate market participation for customers, DER providers, and other service providers than the current trajectory envisioned by the HECO companies.

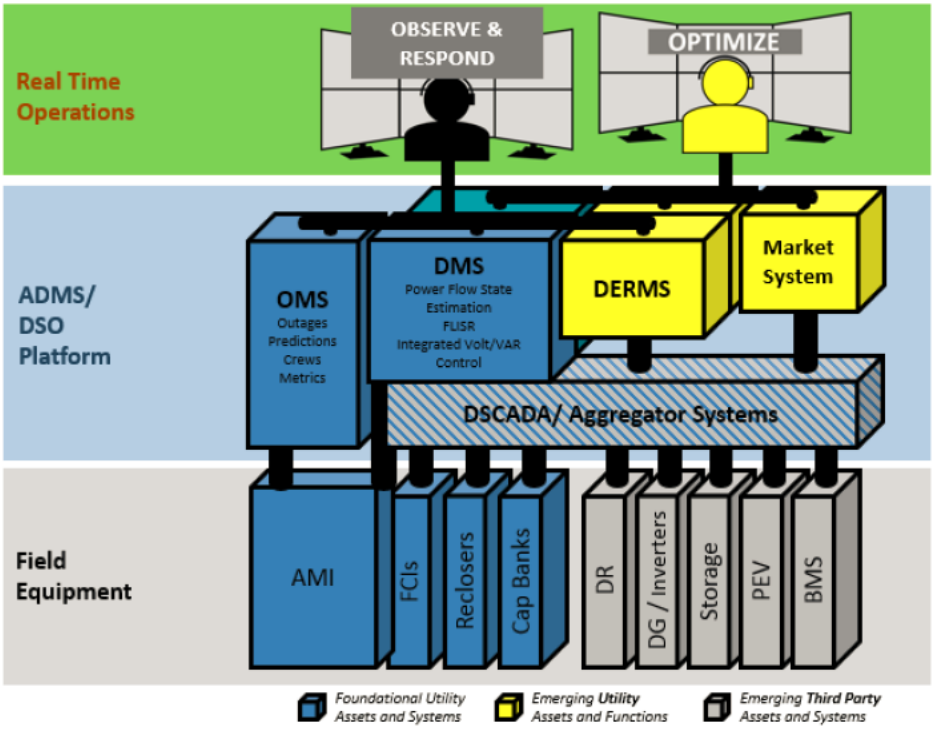
[44] Blockchain is like a distributed ledger which can accept inputs from lots of different parties, but the ledger itself only changes when there is consensus among the group. Information on a blockchain is shared and continually reconciled so there is no need for a central authority. As a shared network, the information held is public but virtually incorruptible. It seems ideally suited for an IDER system since there will be many transactions across the distribution grid. A blockchain network reconciles every transaction that happens in ten-minute intervals, so it can record and manage peer-to-peer energy transactions with little human involvement. Currently, there are several pilots set up to test the use of blockchain in a distributed grid, including a microgrid project in Brooklyn, NY. The HECO Companies' Grid Modernization document does not mention blockchain but acknowledges the potential of Internet of Things to affect customers' lives and business, but as something that requires further grid investment.

Figure 15. Evolution of Distribution Markets and System Capabilities Under the JU Plan



Source: Joint Utilities Supplemental Distributed System Implementation Plan. November 1, 2016. Page 23.

Figure 16. DSP - Enabling Technologies Proposed by the JU



Source: Joint Utilities Supplemental Distributed System Implementation Plan. November 1, 2016. Page 23.

To provide an idea of how much the infrastructure would cost, the Project Team looked at the utilities in New York, which have started making investments in some of the enabling technologies and pilot programs that would eventually lead to a fully-fledged DSP. Figure 17 shows some of the costs for preliminary phases of these projects. These costs may increase in the future and are not exhaustive. The five-year costs range between $11 and $190 million, depending on the technology, utility service area, and current status of utility infrastructure.

There are also pilot projects in New York for transactive energy systems.[45] LO3 Energy, a startup in Brooklyn, has built a blockchain-based microgrid. The Brooklyn Microgrid project now has 60 energy-producing consumers, called "prosumers," and another 500 buyers participating in its market.[46] The company builds both the software platform and accompanying hardware like high-resolution meters. While the costs of the project are not public, LO3 Energy raised $1.2 million from investors in March 2017, $6.3 million in October 2017, and an undisclosed amount from Siemens in December 2017.[47] This blockchain-based microgrid currently augments the existing distribution grid, but it is an example of a market platform where customers can choose their source of energy and DER owners can sell directly to the buyers.

Figure 17. New York's five-year costs for DSP development (2016)

Utility	Customers Served	Technology	Five Year Costs ($ millions)
Orange & Rockland Utilities	230,000	ADMS	$13
Central Hudson Gas & Electric	300,000	DA	$44
		Network upgrades to support DA and ADMS	$47
		ADMS	$7
Niagara Mohawk Power Corporation (Naitonal Grid)	1,600,000	DA	$69
		ADMS	$14
AVANGRID (New York State Electric & Gas; Rochester Gas & Electric)	1,250,000	DA	$190
		ADMS	$25
		GIS grid model	$27
		Enterprise analytics platform	$11
Consolidated Edison	3,400,000	DERMS	$20
		Green Button Connect	$15
		Overall DSP development costs	$133

Source: Tweed, Katherine. "Rate Base It! A Primer on New York's Distributed System Implementation Plans." Greentech Media. July 2016.

[45] Transactive energy systems coordinate energy and payment flows between the grid, customers, and DERs in a manner that takes into accounts both the economics of energy produced or consumed and the engineering specifications of the grid. These systems can thus provide reliability and system security while also increasing the efficiency of grid operations.

[46] Merchant, Emma Foehringer. *Can LO3 Energy Cut Through the Hype on Blockchain?* Greentech Media. November 2017.

[47] S&P Global Market Intelligence. Accessed March 13, 2018.

National Grid is also working with software provider Opus One Solutions to pilot a DSP in the Buffalo Niagara Medical Campus in a 2-year $4.8 million project. The DSP connects the DERs on the campus with the local distribution system. The hardware and software infrastructure behind the DSP sends price signals to DERs based on local system needs and manages their output to optimize grid operations. The two-year pilot costs $6.8 million, of which $2 million is provided as an in-kind cost sharing between project partners and the remaining $4.8 million is budgeted as shown in Figure 18.

Overall, it can be seen that the costs to install the enabling technologies in the early phases for an IDER system operator model in New York can range between about $20 million to more than $250 million over five years. These investment plans have been driven by strong regulatory direction and incorporates demonstration projects featuring partnerships between incumbent utilities and third-party providers, like Opus One and LO3 Energy. The JU have also submitted multiple rounds of system plans and gone through an extensive stakeholder engagement process to identify the needs, solutions, and costs in their territories. Estimating these costs for Hawaii's utilities would require a thorough study of the existing infrastructure of the utilities, the enabling technologies specific to each county, and assumptions about the accompanying regulatory framework.

Figure 18. National Grid/Opus One DSP Pilot Budget

Project Budget Requirement		Phase 1		Phase 2		Phase 3		Total Project	
		CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX
Opus One	Software License - 50% start of phase 2			$500,000				$500,000	
	Software License - 50% start of phase 3					$500,000		$500,000	
	Program management	$250,000		$750,000		$1,000,000		$2,000,000	
	Software development			$2,000,000				$2,000,000	
National Grid	Resources	$250,000		$750,000		$125,000	$125,000	$1,125,000	$125,000
	IT Integration Services			$200,000				$200,000	
	IT Hardware/Software			$25,000				$25,000	
	IT Network and communications			$75,000				$75,000	
	Subtotal	**$500,000**	**$0**	**$4,300,000**	**$0**	**$1,625,000**	**$125,000**	**$6,425,000**	**$125,000**
	Cost Share (in-kind software development)			$2,000,000				$2,000,000	$0
	Annual operational costs				$30,000		$230,000	$0	$260,000
	Total Funding Request	**$500,000**	**$0**	**$2,300,000**	**$30,000**	**$1,625,000**	**$355,000**	**$4,425,000**	**$385,000**

Ongoing Annual Operational Costs		Year 1		Year 2	
		CAPEX	OPEX	CAPEX	OPEX
Opus One	Annual license maintenance 20%		$0		$200,000
National Grid	Integration Services		$20,000		$20,000
	Hardware 10%		$2,500		$2,500
	Network and communications 10%		$7,500		$7,500
	Total Annual Operational Costs	**$0**	**$30,000**	**$0**	**$230,000**

Source: Case 14-M-0101. Niagara Mohawk Power Corporation d/b/a National Grid. "Proposed REV Demonstration Project, Revised Scope – Distributed System Platform." June 2016.

4.5 Grid defection

This is the worst-case scenario which will leave the utility with significant stranded assets across the generation, transmission, and distribution businesses on their hands. Declining costs of

distributed generation in small unit sizes and battery storage may prompt some customers to procure their electricity from their own, or community-owned, sources rather than the monopoly utility. These customers will themselves invest in distributed generation, storage, and energy management systems. If this happens at a sufficiently large scale, the utility cannot recover its investments in generation, transmission, and distribution assets from its revenues at existing rates. For example, a utility may invest in upgrading transmission or distribution substations, or build a new power plant, or enter into a long-term Power Purchase Agreement ("PPA") with an IPP based on forecasts indicating high load growth. If load declines instead because customers leave the grid, the utility faces potential stranded costs.

Historically, utilities have been allowed to recover their stranded costs in investments that were deemed appropriate at the time they were made. From the perspective of a utility's equity investors, allowing a degree of stranded cost recovery represents a reasonable allocation of risk and reward – as they receive a lower return on utility investments, they are entitled to some protection from the risks as well. Even if the burden of these costs is shared between ratepayers and utility investors, this implies raising rates or adding surcharges on their remaining customers – unless utilities can estimate the magnitude of potential stranded assets beforehand and recover a proportionate amount from each customer leaving the grid as a service termination charge. Higher rates could in turn improve the economic justification for grid defection for more customers, exacerbating the problem of stranded costs for the utility.

5 Conclusion

As Hawaii's utilities move towards a 100% renewables future, there will be sizeable investments in the electricity system. These investments will aid in phasing out fossil fuel-fired generation capacity with renewables and storage and replacing aging T&D infrastructure. Due to the variable nature of renewable resources and increasing penetration of behind-the-meter DERs, the utilities must also invest in new technologies and operating capabilities. Moving from the current IOU model (for the HECO Companies) to an electric co-op, a municipal utility, or a grid defection scenario will not require any additional infrastructure investments to operate the electricity grid given that the current utility already has the infrastructure needed to operate the electricity systems and the new owner would have the same operating structure. However, adopting a Single Buyer model or an IDER system operator model changes the nature of the utilities' role in system planning, ensuring resource adequacy, and interfacing with customers and third-party providers. Transitioning to these ownership models will require additional investments to create separate entities and develop new technical capabilities to be able to carry out these new roles.

6 Appendix A: Scope of work to which this deliverable responds

Task 1.1.4 Assessment of future needs for generation, transmission and distribution infrastructure in each county.

CONTRACTOR shall determine which facilities would likely need to be acquired and/or constructed as part of the establishment of a new electric utility ownership model (generation, transmission and distribution facilities; operations center, fleet, warehouse facilities, office facilities, and material yards).

DELIVERABLE FOR TASK 1.1.4. CONTRACTOR shall provide its conclusions and all work to assess which facilities need to be acquired and/or constructed as part of the establishment of each selected ownership model. CONTRACTOR shall provide written narrative in MS Word, spreadsheets in MS Excel, as well as an index of all source information used to generate the assessment. CONTRACTOR shall submit deliverable for TASK 1.1.4 to the STATE for approval.

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Identification of system improvements planned for installation in the next five years and proposed improvements needed through 2045

prepared for Hawaii DBEDT by London Economics International LLC

October 31, 2017

London Economics International LLC ("LEI"), together with Meister Consultants Group, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State of Hawaii in achieving its energy goals; this document is one of several working papers associated with that engagement. With the State's clean energy goals, the aging generation and transmission infrastructure, anticipated influx of distributed energy resources ("DERs") and projected moderate load growth, improvements in the electricity systems are necessary to ensure reliability, maintain grid security, and offer greater flexibility in transmission operations. The Hawaiian Electric Companies ("the HECO Companies") and the Kauai Island Utility Cooperative ("KIUC") have laid out their improvement plans for the future (next five years and beyond) and these are summarized in this memo.

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List of acronyms

APGP	Alternative Power Generation Plan
BESS	Battery energy storage system
DBEDT	Hawaii Department of Business, Economic Development and Tourism
DER	Distributed Energy Resource
DESS	Distributed energy storage systems
DGPV	Distributed-generation photovoltaic
DMS	Distributed management system
DR	Demand response
FCI	Faulted circuit indicators
FFR1	Fast Frequency Response 1
FIT	Feed-In-Tariff
HECO	Hawaiian Electric Company, Inc.
HEI	Hawaiian Electric Industries, Inc.
HELCO	Hawaii Electric Light Company, Inc.
HIEC	Hawaii Island Energy Cooperative
HPUC	Hawaii Public Utilities Commission
ICE	Internal combustion engine
IFO	Industrial fuel oil
JBPHH	Joint Base Pearl Harbor-Hickam
KIUC	Kauai Island Utility Cooperative

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KMCBH	Kaneohe Marine Corps Base Hawaii
KPP	Kahului Power Plant
LNG	Liquefied natural gas
LSD	Low Sulfur Diesel
LSFO	Low Sulfur Fuel Oil
MDMS	Meter data management system
MECO	Maui Electric Company, Ltd.
NPDES	National Pollution Discharge Elimination System
NTAs	Non-transmission alternatives
OMS	Outage management system
PSH	Pumped storage hydro
PSIP	Power System Improvement Plan
RPS	Renewable Portfolio Standards
T&D	Transmission and distribution

1 Executive Summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State of Hawaii in achieving its energy goals. This working paper, which corresponds to Task 1.1.5 in the project scope of work, identifies system improvements planned for installation in the next five years (2017-2021) and proposed improvements needed through 2045 (2022-2045). We have also compared the options discussed in Hawaiian Electric Companies'[1] ("the HECO Companies") Power Supply Improvement Plan Update Report ("PSIP") to see if one or some of the options would be specifically required to provide safe, reliable service to customers.

The Project Team determined the following as the key drivers to the system improvements:

- achieving the State's 100% clean energy goals by 2045;
- aging generation and transmission/distribution infrastructure;
- influx of distributed energy resources ("DERs");
- new entry plants to achieve the RPS targets;
- retirements of old plants; and
- projected -0.02% to 2.33% per year load growth (peak demand in terms of MW), for the next 5 years depending on the county, and -0.1% - 0.80% per year from 2017 to 2045, depending on the county.[2]

Based on their near-term and long-term plans, both the HECO Companies and Kauai Island Utility Cooperative ("KIUC") are ahead of their renewable energy goals and both will be able to achieve the clean energy target before 2045. To ensure that the HECO Companies and KIUC could accommodate significant amount of distributed generation, they plan to use energy storage and other grid technologies to modernize and support the reliability of the grid. The HECO Companies provided detailed plans of generation improvements in its PSIP and grid modernization for the near term, while KIUC had a general strategic plan for 2016-2030. The short-term plan of the HECO Companies, under the grid modernization report, include: establishing data management system and operational systems, distributing smart meters strategically rather than system-wide, relying on advanced inverter technology to enable greater private rooftop solar adoption, expanding use of voltage management tools and sensors and automated controls at substations and neighborhood circuit, and enhancing outage management and notification technology.

As for long term, there is no publicly available information from KIUC for the long term beyond 2030, while the HECO Companies presented several options as resource plans for the long term.

---

[1] Hawaiian Electric Companies, Inc. includes Hawaii Electric Light Company, Inc. ("HELCO") and Maui Electric Company Limited ("MECO").

[2] This is projected load growth for the counties served by the HECO Companies. No public data is available for the Kauai County.

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However, evaluating the choice among these options is subject to many factors, including how the near-term plans are implemented, potential technology innovation, financial and political feasibility, etc. Thus, instead of selecting a preferred plan, LEI compared these plans and then presented the differences and similarities between these options. As for the grid, the HECO Companies presented transmission upgrade plans and discussed the feasibility of interisland transmission. They also aim to leverage energy storage and advanced grid technologies to modernize the grid over time, but the information about long-term plans is limited.

In summary, improvements in generation and transmission infrastructure are required to ensure grid security, maintain reliability, support influx of renewables, and offer greater flexibility in transmission operations with the increase in distributed energy resources.

Figure 1. Drivers and proposed improvements

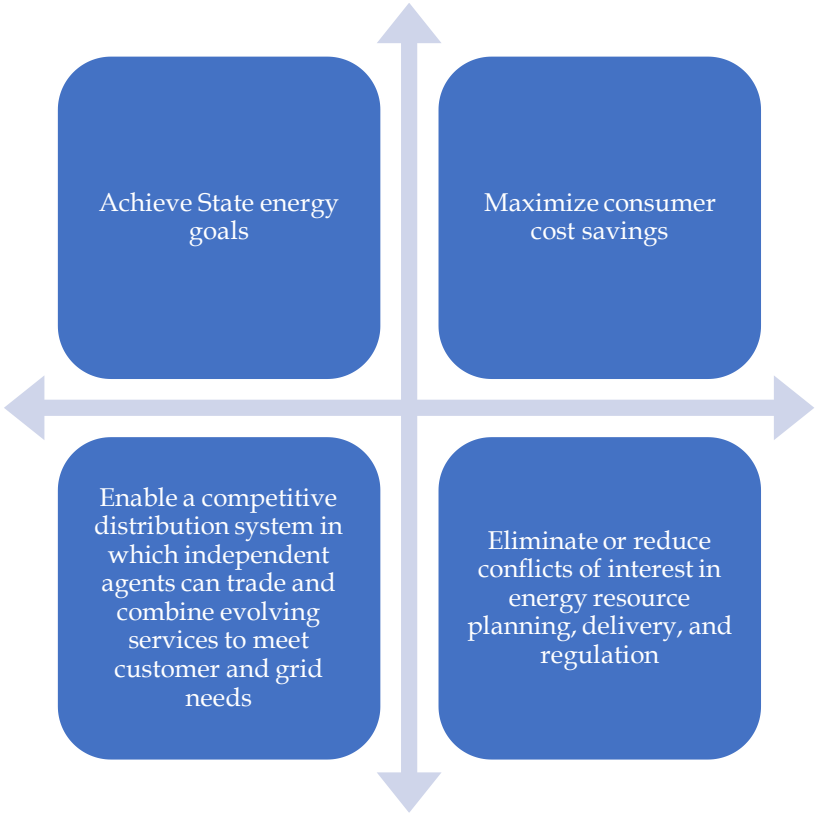
Drivers	Proposed improvements
Meeting the State's clean energy goals	Proposed adding renewables and energy storage; retirement of thermal plants; transmission upgrades and expansion as well as grid modernization to accommodate more renewables
Aging generation and transmission infrastructure	Plant retirements and new installations; transmission upgrades to replace aged and deteriorated transmission components (e.g., poles, insulators, etc.); SCADA upgrade to extend system's next life cycle
Increasing penetration of distributed energy resources	Utilize advanced grid technologies into the distribution system to provide access to other flexible power resources; deploy autonomous resources
Moderate load growth	New plant installations
Continuing the utilities' mandate to provide reliable energy service	Proposed adding renewables to serve load; utilize customer-facing technologies; establish a single network operations center to manage the network on all islands served, etc.

2 Introduction and scope

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[3] was contracted to perform this study.[4]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[5] listed in Figure 2.

Figure 2. State's key criteria in evaluating the models



Source: Scope of Services under Contract No. 65595

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In

[3] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[4] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[5] House Bill No. 1700 Relating to the State Budget.

addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[6]

2.1 Role of this deliverable relative to others in the project

This deliverable is responsive to Task 1.1.5 in the project scope of work. It identifies, on a high level, the system capital improvements needed and planned for installation in the next five years, and for the subsequent years through 2045.

2.2 Future refinements

As noted earlier, this deliverable is subject to further refinement and changes as the project moves forward and as we receive more information from the utilities on their future.

[6] Hawaii Contract No. 65595. Scope of Services.

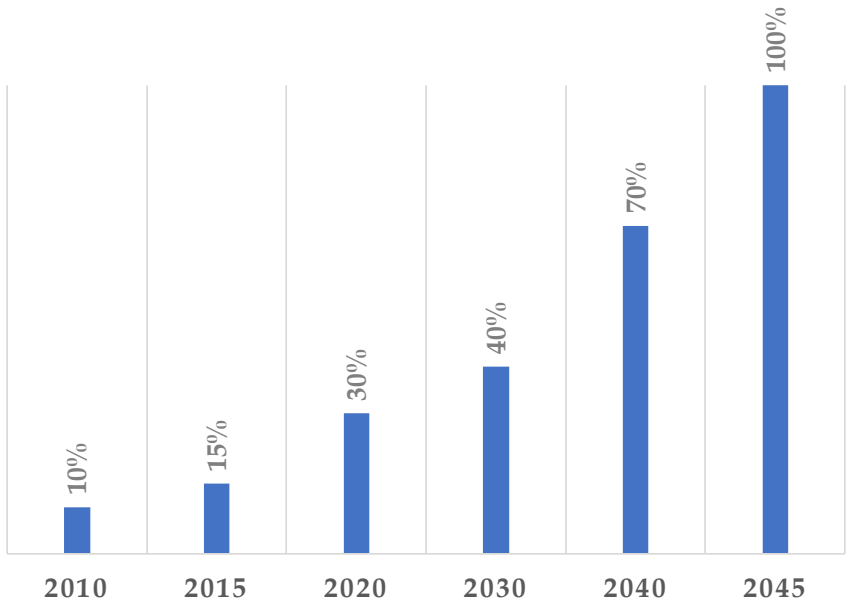
3 Key drivers of system improvements

The primary factors driving system improvements include the State's clean energy goals of increasing more renewables current conditions of the assets (i.e., age) and supply-demand dynamics. On the supply side, the key drivers include new entry of not just the power plants but also distributed energy resources ("DER"), as well as plant retirements. On the demand side is the load growth forecasts. Energy efficiency improvements, customer-sited distributed generation photovoltaic ("DGPV"), as well as the demand from electric vehicles are all taken into consideration in the demand forecast. These key drivers will be discussed in the following subsections.

3.1 Clean energy goals

Hawaii's renewable portfolio standard ("RPS") requires fossil fuels to be eliminated from the power mix by 2045. According to the law, each electric utility company that sells electricity for consumption in the State should generate a certain percentage of their electricity sales from renewables. Figure 3 shows the renewable targets for specified years.

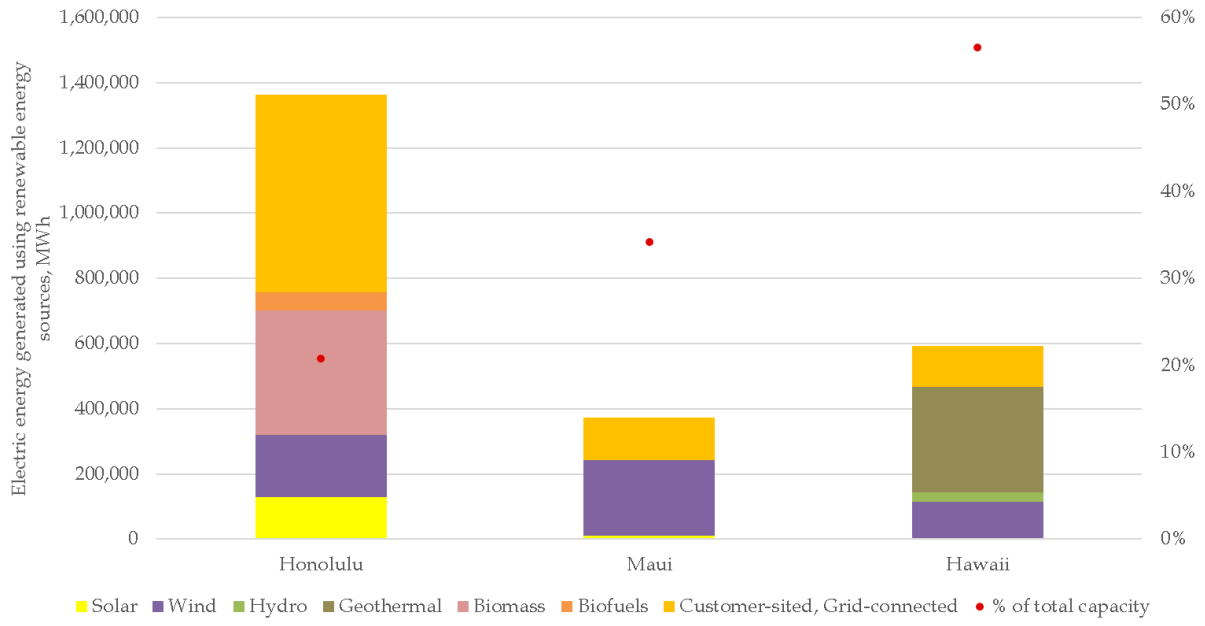
Figure 3. Hawaii's RPS targets



Source: HI Rev Stat § 269-92 (2015).

As of 2017, Hawaii County has the most renewable energy in terms of electricity sales – about 56.6%, followed by Kauai County (40.0%)[7] then Maui County (34.2%) Honolulu County has the least – about 20.8% of the total sales.[8]

Figure 4. Hawaii State renewable energy sales (the HECO Companies), 2017



Note: Kauai's 2017 data has not been released yet as of April 3, 2018.
Source: HECO Companies. 2017 Renewable Portfolio Standard Status Report. December 31, 2017.

To continue its progress towards achieving the RPS targets, the HECO Companies plan to seek new renewable energy projects for Oahu, Maui, and Hawaii beginning in early 2018. The Hawaii Public Utilities Commission ("PUC") granted earlier in October 2017 the HECO Companies' request to start the regulatory process to issue requests for proposals enabling its execution of the five-year action plan for more renewable generation. The HECO Companies intend to issue RFPs in two stages over the next two years for renewable resources it targeted through 2022. Those resources include 220 MW of renewable generation for Oahu, 110 MW for the island of Maui (including 40 MW firm renewable generation, and 50 MW for the island of Hawaii. Sections 3.1.1 and 3.1.2 below discuss the utilities' short-term and long-term RPS goals, respectively.

[7] KIUC's 2017 Annual RPS Status Report had not been released when this memo was finalized. "40%" was retrived from KIUC's website (http://website.kiuc.coop/content/about-us, access date: April 3, 2018).

[8] Percentages are based on the amount of electricity generated by the Hawaiian Electric Companies and purchased from independent power producers in 2017, customer sided grid connected technologies are included. (Source: The HECO Companies. *Clean Energy Facts*. Website. Access Date: April 3, 2018. < https://www.hawaiianelectric.com/clean-energy-hawaii/clean-energy-facts>)

Furthermore, with the State's clean energy goals, the HECO Companies and KIUC need to ensure that the grid can accommodate the anticipated increase in customer-owned distributed resources and grid-scale resources. The HECO Companies have acknowledged that the current grid must be transformed from "one that is designed for one-way power flow from a few central generating stations to one that safely and reliably enables two-way power flow from many resources."[9] The HECO Companies has identified some system improvements in their Grid Modernization strategy, which is discussed in Section 4.2.2.

3.1.1 Short-term RPS goals (next five years)

Having achieved 23.2% of the RPS target by 2015, the HECO Companies surpassed the state's 2015 RPS target of 15%.[10] According to HECO's PSIP they expect to achieve the future RPS targets ahead of schedule, anticipating reaching 48% renewable energy target by 2020, 18% more than mandated by the state's RPS rules.[11] By 2021, each island is forecast to meet more than 40% of the RPS target as shown in Figure 5.

Figure 5. Forecasted RPS and renewables (MW) by 2021

Island and County	Forecast RPS (%)	Forecasted Renewables (MW)
Molokai Island (Maui County)	142%	8.50
Hawaii Island (Hawaii County)	80%	235.30
Maui Island (Maui County)	63%	284.00
Lanai Island (Maui County)	59%	6.70
Oahu Island (Honolulu County)	45%	1,299.00

Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 1, pages 6-11 to 6-21.

Likewise, KIUC has exceeded the 2016 RPS goal of 30% by having 41.66% of its net electricity sales from renewable energy resources.[12] The RPS level in 2016 has also surpassed the 30% by 2020 RPS goal by 11.66% and the 40% goal by 2030 RPS requirement by 1.66%. Moreover, KIUC expects to reach 50% renewable in 2018 – five years ahead of the initial goal in Strategic Plan 2008-2023.[13] According to KIUC's 2016 Annual RPS Status Report, it is on target to exceed the next RPS

[9] The HECO Companies. Modernizing Hawaii's Grid for Our Customers. Page 3. August 2017.

[10] Hawaiian Electric Company. "Record highs for renewable energy use in 2015." April 2016. <https://www.hawaiianelectric.com/Documents/my_account/customer_newsletter/hawaiian_electric/2016/hawaiian_electric_2016_04.pdf>

[11] HECO. *PSIP Update Report*. December 23, 2016. Book 1, page 41.

[12] KIUC. "Docket No. 2007-008 - In the Matter of Public Utilities Commission Instituting a Proceeding to Examine Hawaii's Renewable Portfolio Standards Law, Hawaii Revised Statutes ("HRS") §§ 269-91 — 269-95, as Amended by Act 162, Session Laws of Hawaii 2006: Kauai Island Utility Cooperative's ("KIUC's") 2015 Annual Renewable Portfolio Standards ("RPS") Status Report." April 11, 2017.

[13] KIUC. *KIUC Board Sets Renewable Energy Goal of 70 percent by 2030*. February 1, 2017.

requirement of 70% by 2040.[14] As of 2017, more than 40% of KIUC's electricity came from renewable energy sources.[15]

KIUC is committed to increase the growth of renewable energy by signing power purchase agreements from various independent power producers ("IPPs") such as the following:[16]

- SolarCity for the purchase of electricity generated from the Kapaia Solar and battery facility;
- Gay & Robinson for the purchase of electricity generated from a new hydroelectric facility; and
- AES Distributed Energy for the purchase of electricity from a new solar and battery facility.

Furthermore, KIUC is looking for additional solar plus storage projects which could provide an additional 10-20% points toward its annual RPS in 2019.[17]

3.1.2 Long-term RPS goals

As reported in the PSIP and shown in Figure 6, the HECO Companies expect to reach the next mandate of "30% RPS by 2020" by 2018, two years early. And by 2030, the RPS could be upwards of 72%, exceeding the state mandate of 40%. The 100% renewable goal can be reached by 2040, ahead of the 2045 deadline.[18]

As for KIUC, it aims to generate at least 70% of electricity by using "cost effective renewable resources" by 2030 based on its Strategic Plan Update 2016-2030. This new goal will enable KIUC to achieve the 100% renewable energy goal by 2035, 10 years ahead of the state RPS mandate.

With these RPS goals, fossil-fuel plants need to be retired, new renewable resources and storage need to be installed, and the grid needs to be modernized to provide access to these new generation resources and to meet the state's energy goals.

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[14] KIUC. "Docket No. 2007-008 - In the Matter of Public Utilities Commission Instituting a Proceeding to Examine Hawaii's Renewable Portfolio Standards Law, Hawaii Revised Statutes ("HRS") §§ 269-91 — 269-95, as Amended by Act 162, Session Laws of Hawaii 2006: Kauai Island Utility Cooperative's ("KIUC's") 2015 Annual Renewable Portfolio Standards ("RPS") Status Report." April 11, 2017

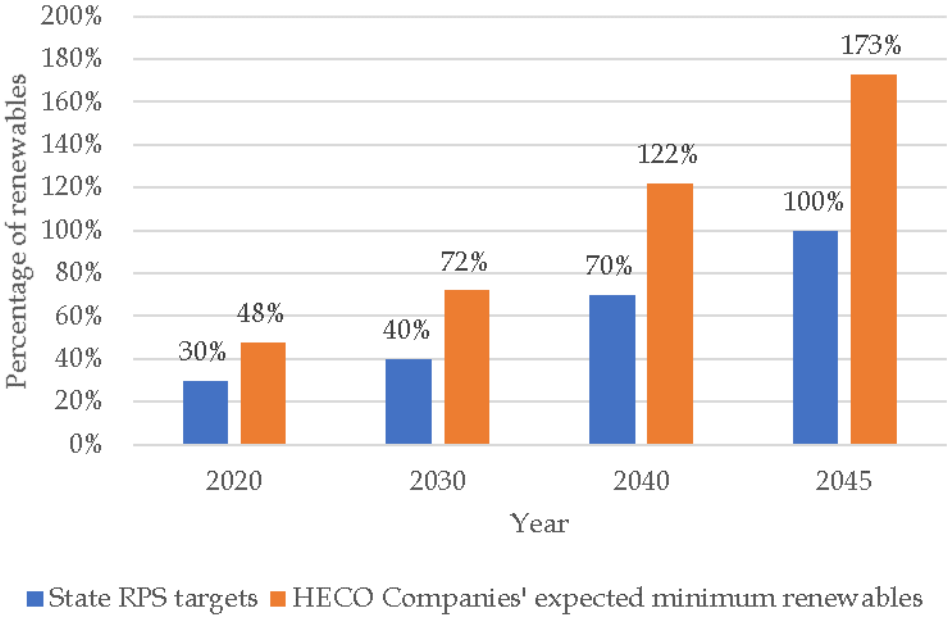
[15] KIUC. *About us*. Website. <http://website.kiuc.coop/content/about-us>. Access date: April 3, 2018.

[16] Ibid.

[17] Ibid.

[18] HECO. *PSIP Update Report*. December 23, 2016. Book 1, page ES-1.

Figure 6. State of Hawaii's RPS mandates and the HECO Companies' expected minimum



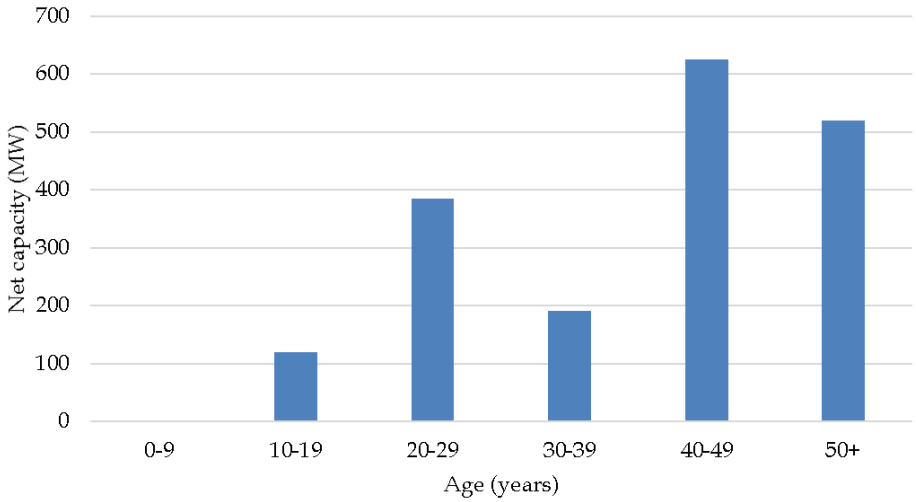
Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 1, page ES-1.

3.2 Aging generation and transmission infrastructure

As analyzed in Task 1.1.3, almost half of the thermal plants in Hawaii are close to the end of the average useful life of oil-fired plants based on a sample of retired units in the US (depending on technology).[19] In fact, all the counties have oil-fired plants that are older than 40 years. More than 900 MW of Honolulu's capacity is from oil-fired plants that are older than 40 years. Figure 7 shows a breakdown of the age of thermal plants in the State, and Figure 8 shows the average retirement age of oil-fired plants by technology in the US. Therefore, some of these plants will need to be retired in the next several years. PSIP has laid out the HECO Companies' retirement plan, which is discussed in Section 4.1.2.

[19] A brief discussion of the average age of retired oil-fired plants is discussed in Task 1.1.3.

Figure 7. Age of oil-fired plants in Hawaii



Source: The HECO Companies. PSIP Book 2. KIUC website.

Figure 8. Average retirement age of oil-fired plants by technology in the US

	Combustion Gas Turbine	Internal Combustion Engine	Steam Turbine
Distillate Fuel Oil	32	34	44
Residual Fuel Oil	28	45	48

Note: Based on 148 oil-fired retired in the US.
Source: Energy Velocity

Likewise, the HECO Companies' transmission and distribution ("T&D") assets are approaching the end of their useful life and needs to be upgraded or replaced.[20] According to the HECO Companies, much of the installed T&D infrastructure was from 30 to 60 years ago as shown in Figure 9, Figure 10, and Figure 11.[21] Among the HECO Companies, HECO has the largest T&D infrastructure assets, especially with a significant increase in the past few years.

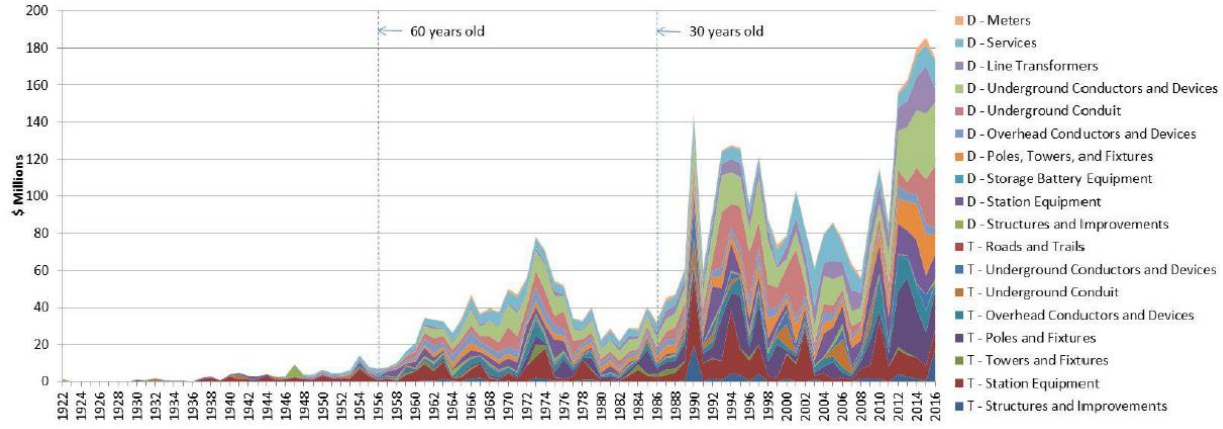
As the HECO Companies noted, T&D infrastructure deteriorates due to many natural or human factors. The HECO Companies has an ongoing infrastructure replacement program to maintain the reliability of the grid to comply with the transmission reliability and security compliance standards and to avoid catastrophic events from happening. It is also noted that the replacement

[20] HECO Companies. *Modernizing Hawaii's Grid for Our Customers*. August 2017 Draft Report. Page 53.

[21] HECO Companies. *Modernizing Hawaii's Grid for Our Customers*. August 2017 Draft Report. Pages 54-55.

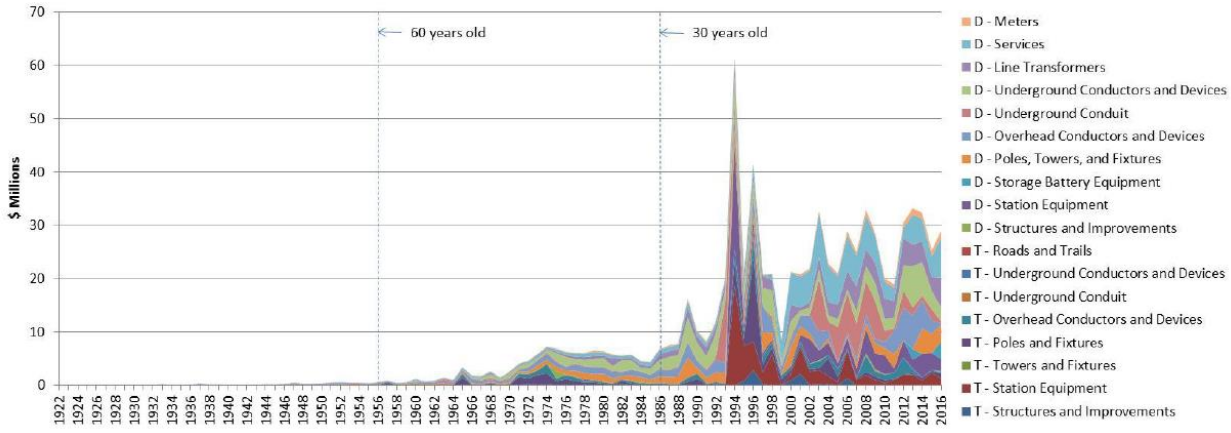
of aging infrastructure costs more than the original installation because of the increased scope and complexity of replacement projects.[22]

Figure 9. HECO in-service T&D infrastructure assets (2016$)



Source: HECO Companies. Modernizing Hawaii's Grid for Our Customers. August 2017 Draft Report. Page 54-55.

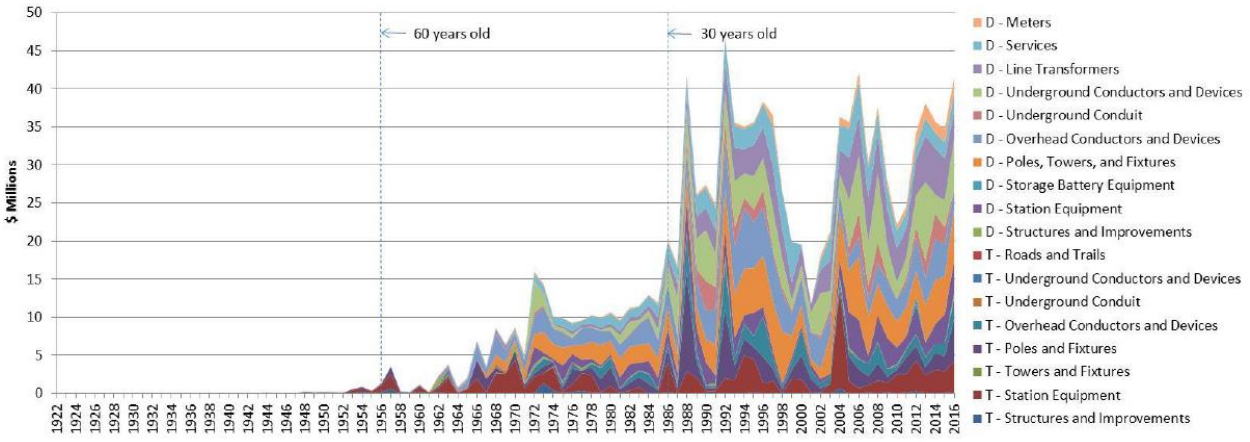
Figure 10. MECO in-service T&D infrastructure assets (2016$)



Source: HECO Companies. Modernizing Hawaii's Grid for Our Customers. August 2017 Draft Report. Page 54-55.

[22] Ibid.

Figure 11. HELCO in-service T&D infrastructure assets (2016$)



Source: HECO Companies. Modernizing Hawaii's Grid for Our Customers. August 2017 Draft Report. Page 54-55.

3.3 Influx of distributed energy resources

Distributed energy resources ("DER") include a wide range of generating or load reducing technologies on a utility's distribution system or on the premises of an end-use consumer. Hawaii has witnessed rapid growth in solar PV penetration due to high levels of fuel import costs, retail tariffs, and solar irradiation levels. This has been further supported by the State's 100% clean energy target. Not all DERs are connected to the utility or can be controlled by grid operators.

> DERs, as defined in HECO Companies' Grid Modernization plans, include distributed generation resources, distributed energy storage, demand response, energy efficiency, and electric vehicles that are connected to the electric distribution power grid and behind-the-meter at a customer's premises.
>
> *Source: HECO Companies' Grid Modernization Plan (Appendix A, page 4)*

As Figure 12 shows, both utility-scale and customer-sited solar PV capacity has grown rapidly in the territories served by the HECO Companies, with most of the customer-sited capacity growth occurring on Oahu (Figure 13). According to the HECO Companies' High DG-PV scenario as summarized in Figure 14, distributed solar PV is forecast to grow to 3 GW in their territories by 2045. In Kauai county, about 3,700 KIUC members have solar PV systems on their homes or businesses, providing about 20 MW to the grid.[23]

As distributed generation becomes more prevalent, the needs and functions of the grid are changing as well. According to the HECO Companies, about 80,000 privately owned rooftop solar systems use the grid to deliver electricity to other customers.[24] In other words, distributed energy

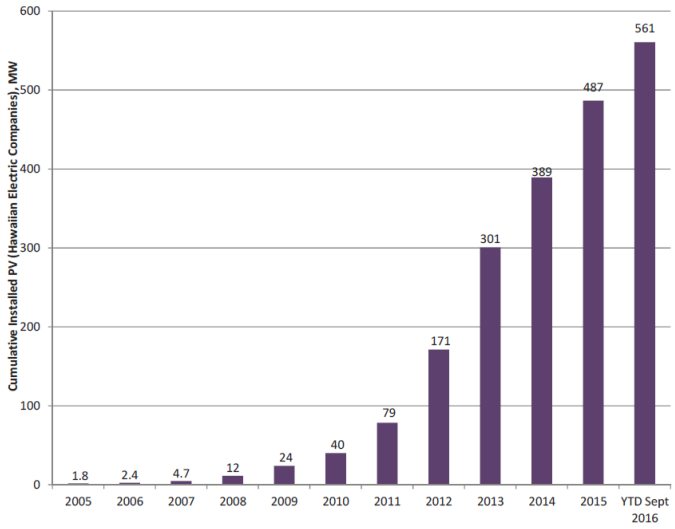
[23] Kauai Island Utility Cooperative. *Strategic Plan Update: 2016-2030*. January 31, 2017. Page 2.

[24] HECO Companies. *Modernizing Hawaii's Grid for Our Customers*. August 29, 2017. Page ES-1.

resources exist in every neighborhood, which requires the grid to be more flexible, digital, and adaptable to accommodate two-way flow of electricity between the customer and the utility.[25]

Some DERs, such as distributed solar PV, can have a significant impact on the system load. Therefore, with the increasing DER penetration, there is a greater need for the transmission system to detect and respond promptly to balance the supply and demand when those generation sources are unavailable, need ramping support, or are unable to meet customer demand. Furthermore, it is also important that the utilities maintain systemwide reliability by providing access to other flexible power resources in cases when such variable power supply is offline or not available. The HECO Companies have taken this into account in their Grid Modernization plan as discussed in Section 4.2.2.

Figure 12. PV (DG+IPP) Generation Growth, the HECO Companies consolidated



Source: HECO Companies. PSIP Update Report. Book 2. December 23, 2016. Page D-33.

Figure 13. Installed Residential and Commercial PV

Utility	Number of PV Systems			PV Capacity (MW)		
	Residential	Commercial	Total	Residential	Commercial	Total
Hawaiian Electric	44,267	1522	45,789	243.4	148.6	392.0
Maui Electric	10,148	782	10,930	56.7	30.7	87.4
Hawai'i Electric Light	10,263	647	10,910	52.4	26.9	79.3
Totals	*64,678*	*2,951*	*67,629*	*352.5*	*206.2*	*558.7*

Source: HECO Companies. PSIP Update Report. Book 2. December 23, 2016. Page D-33.

Figure 14. DG-PV Forecast

[25] Ibid.

High DG-PV Forecast Cumulative Installed Capacity								
Island	**2016**	**2017**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**
Oahu	407	479	606	867	1,175	1,484	1,793	2,101
Maui	98	115	132	178	243	307	371	435
Lanai	0.8	1.3	1.5	2.5	3.8	5.2	6.5	7.8
Molokai	2.1	2.5	3.4	4.0	4.7	5.5	6.3	7.1
Hawaii	88	103	115	174	244	315	386	456
Total	**596**	**701**	**858**	**1,226**	**1,671**	**2,117**	**2,563**	**3,007**

Source: HECO Companies. PSIP Update Report. Book 3. December 23, 2016. Page J-60 – J-64.

3.4 Load growth

The HECO Companies' PSIP provided a forecast of the load profile as well as load growth for each island. Energy efficiency improvements, customer-sited DGPV, as well as the demand from electric vehicles are all taken into consideration in its forecast.

3.4.1 Load growth (2017-2021)

The HECO Companies projected a relatively flat load growth for the next five years. Oahu's load growth is projected to decline on average from 2017 to 2021 while Molokai's load growth is relatively flat for the next five years. Load growth (peak demand in terms of MW) in Maui and Hawaii are less than 1% per year at an average of 0.97% and 0.78%, respectively. It is only Lanai where the load growth is expected to be higher than 1%.

As shown in Figure 15, Honolulu County (Oahu)'s peak load will increase from 2017 and reach the highest peak load of 1,199 MW in 2018/2019, and then go down to 1,181 MW in 2021. Maui's peak load will continue to grow by 0.97%(on average) per annum from 207 MW in 2017 to 215 MW in 2021. Lanai and Molokai have much lower peak load. Peak load of Lanai will increase by 2.33% on average per year from 5.3 MW in 2017 to 5.8 MW in 2021. Molokai has a projected constant peak load of 5.5 MW from 2017 to 2021.[26] Hawaii County's peak load is projected to grow from 188 MW in 2017 to 194 MW in 2021.[27]

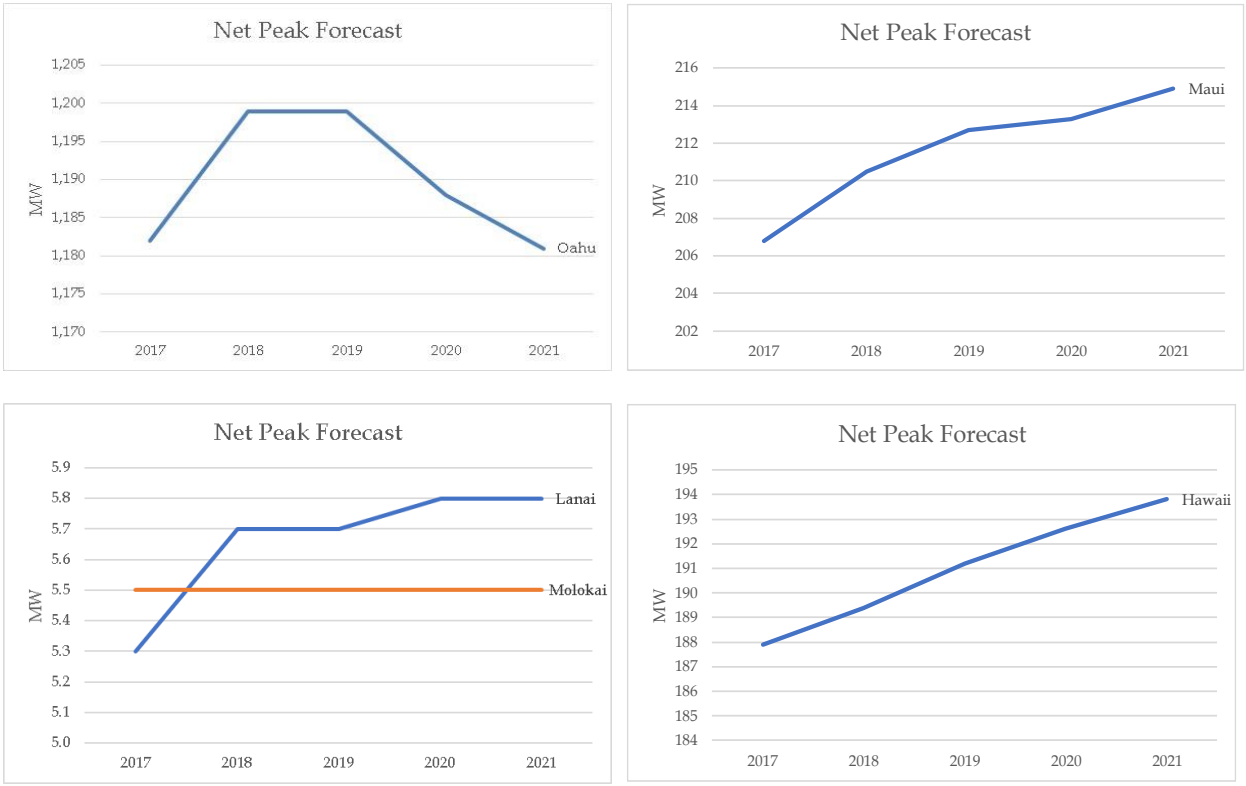
KIUC, on the other hand, does not have publicly available load forecast for the near term or long term. However, KIUC plans to maintain system reliability and price stability while moving forward to achieve the renewable energy goal. For instance, according to KIUC's strategic plan (2016 - 2030), any new renewable generation source that is added should be no more than 20% of Kauai's electric usage in any single year.[28]

[26] HECO Companies. *PSIP Update Report*. December 23, 2016. Book 3. Page J-50 – J-55.

[27] Ibid.

[28] KIUC. *Strategic Plan Update 2016-2030*. January 31, 2017 (Adopted).

Figure 15. Load growth near term



Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 3. Page J-50 – J-55 (pdf 141-145).

3.4.2 Load growth (2022-2045)

Likewise, the HECO Companies' PSIP forecasted the load profile for each island from 2022 to 2045. Similar to the load forecasts for the first five years, energy efficiency improvements, customer-sited DGPV, as well as the demand (MW) from electric vehicles ("EV") are all taken into consideration in its peak demand forecast.

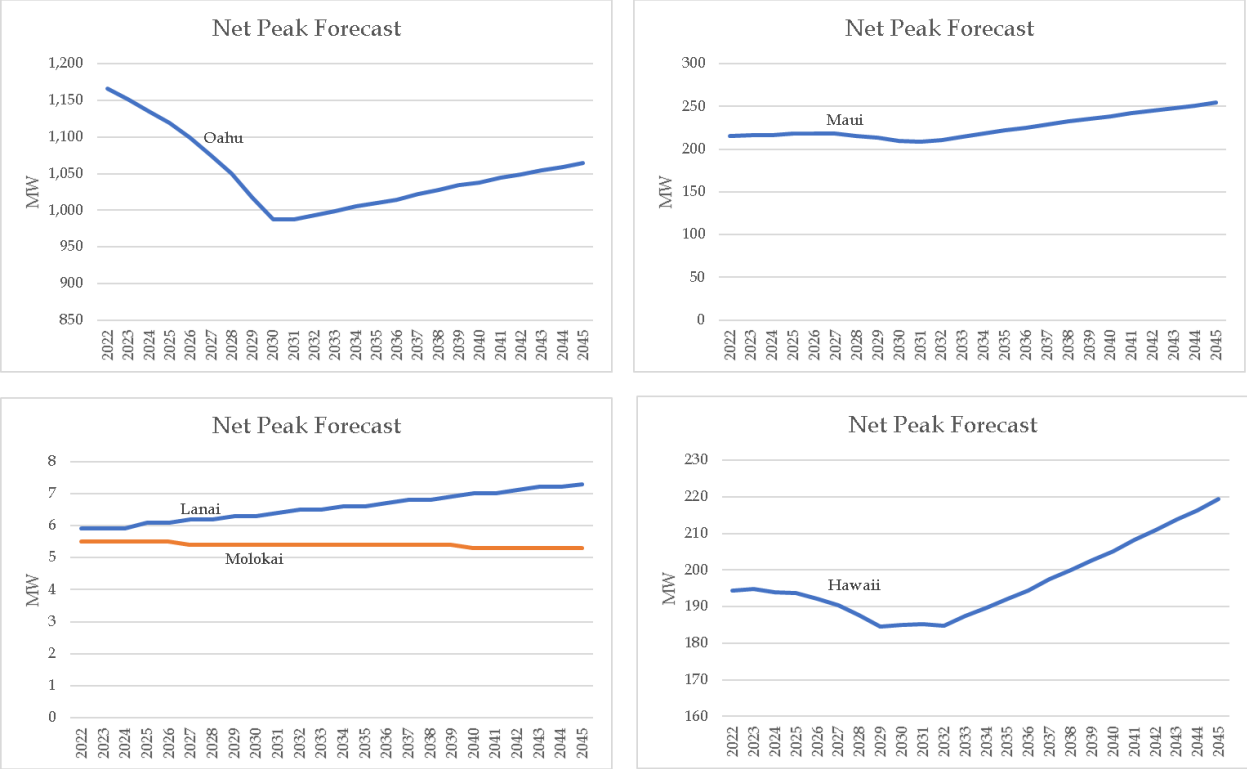
For the next 28 years, the HECO Companies project that on average, load growth (peak demand in terms of MW) will be negative in Oahu and Molokai at -0.4% per year and -0.1% per year, respectively. Lanai would have the highest growth rate at an average of 1.2% per year from 2017 to 2045. This is followed by Maui at an average of 0.8% per year and Hawaii at 0.6% per year.

As shown in Figure 16, Honolulu County (Oahu)'s peak load will decrease from 2022 and reach the lowest peak load of 999 MW in 2033, and then increase to 1,065 MW in 2045. Maui's peak load will be flat from 2022 to 2033 with an average of 215 MW, and then grow from 218 MW in 2034 to 255 MW in 2045. Lanai and Molokai have much lower peak load. Peak load of Lanai will increase by an average of 0.9% per year from 5.9 MW in 2022 to 7.3 MW in 2045, while Molokai has a constant peak load of 5.5 MW from 2022 to 2026, 5.4 MW from 2027 to 2039, and 5.3 MW

from 2040 to 2045.[29] Hawaii's peak load will decrease by 0.5% per annum from 194 MW in 2022 to 184 MW in 2032, and then grow from 187 MW in 2033 to 219 MW in 2045.[30]

Given these load forecasts, there is a need to ensure that resources are adequate to meet the load, and the grid is stable to accommodate new supply coming online. Moreover, it is also necessary to find cost-effective methods to better utilize the generating resources and facilities when the load declines in certain periods.

Figure 16. Load growth long term



Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 3. Page J-50 – J-55.

4 System improvements planned in the next five years

The HECO Companies aim to achieve the RPS targets ahead of schedule, which requires more renewable resources to be added to the system, and a reliable grid to accommodate these renewables. Furthermore, the forecasted average load growth (peak demand in terms of MW,

[29] HECO Companies. *PSIP Update Report*. December 23, 2016. Book 3. Page J-50 – J-55.

[30] Ibid.

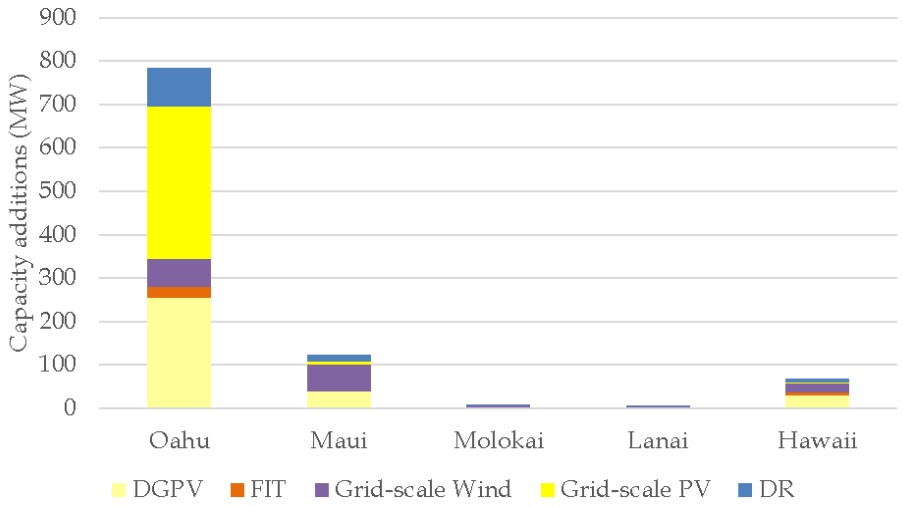
from 2017 to 2021) of -0.02% and 2.33% in the different islands[31] and the influx of large number of distributed renewables require a fully responsive grid that can harness distributed, behind-the-meter resources and respond automatically to fluctuating demand and power supply conditions. This section identifies the generation and transmission/distribution improvements planned by the HECO Companies and KIUC.

4.1 System improvements planned: generation

The HECO Companies and KIUC plan to add new plants to meet the demand of the state and to retire some of the old plants. The HECO Companies' PSIP books and KIUC's website are the primary sources used in the discussion about the new entry and retirements.

4.1.1 New plant installations

Figure 17. 2017-2021 renewable energy and demand response additions on each island



Note: FIT: Feed-In-Tariff; DR: Demand Response.
Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 1. Page 22.

To comply with the State's clean energy goal, the HECO Companies aim to add nearly 800 MW of new renewable generating capacity by 2021. This includes grid-scale solar, distributed generation PV, and wind resources,[32] about 326 MW of distributed solar generation,[33] and about 110 MW of demand response program resources.[34] Figure 17 shows the renewable generation

[31] The average peak demand growth (in terms of MW) from 2017 to 2021 in each island: Oahu: -0.02%, Maui: 0.97%, Lanai: 2.33%, Molokai: 0.00%, Hawaii: 0.78%.

[32] HECO. *PSIP Update Report*. December 23, 2016. Book 1. Page 6-11 to 6-21.

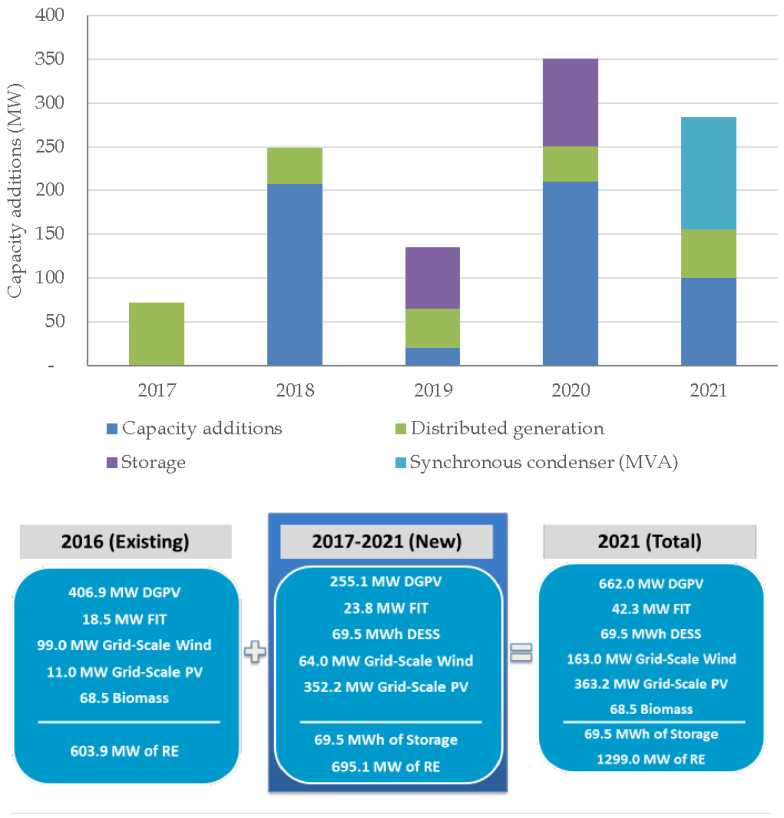
[33] Ibid.

[34] Ibid.

additions planned in the next five years for each island. Most of these new additions will be located in Oahu and will be predominantly grid-scale PV.

In Honolulu County, grid-scale PV will have the most significant increase (from 11 MW in 2016 to 363.2 MW in 2021) in the next five years. In addition, there will be a sizeable increase in DGPV, storage, grid-scale wind, and Feed-In-Tariff ("FIT") as well.[35] A total of 695.1 MW of renewables and 69.5 MWh of storage are planned to be added in Oahu. Figure 18 shows the planned capacity additions, distributed generation, storage, and synchronous condensers in Honolulu County.

Figure 18. PSIP near-term resource plan summary for Honolulu County (Oahu Island)



Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 1. Page 6-11 (page 164 of pdf).

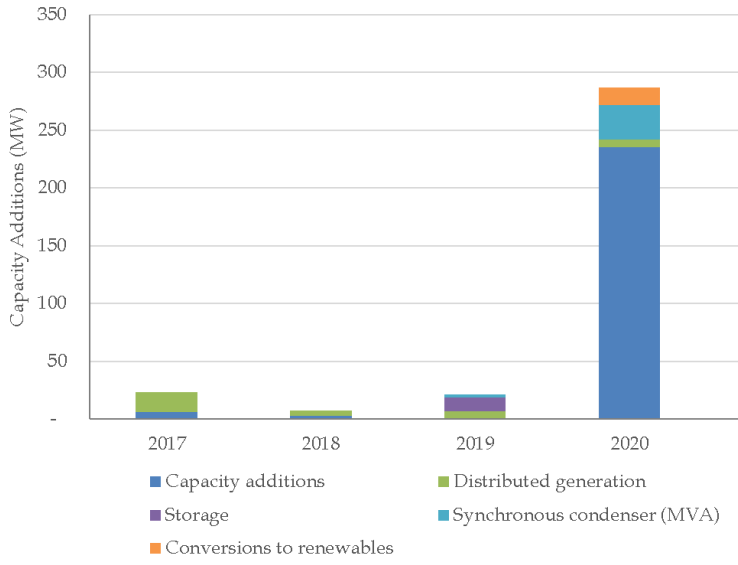
Maui County will focus more on grid-scale wind and proposes to add a total of 71 MW of wind from 2017 to 2021. Additionally, DGPV will increase by 40% or 40.5 MW, and storage will grow from 0 to 11.2 MWh. There will be an additional 6.7 MW of grid-scale PV and 1 MW of FIT during the five-year period.[36] In total, an additional 695.1 MW of renewable energy is anticipated to be

[35] The HECO Companies. *PSIP Update Report.* December 23, 2016. Book 1. Page 6-11.

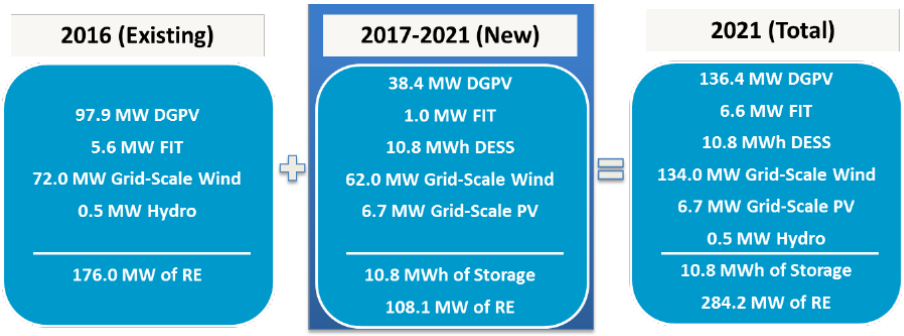
[36] The HECO Companies. *PSIP Update Report.* December 23, 2016. Book 1. Page 6-13 – 6-19.

added to the system by 2021.[37] Of the three islands, most of these new additions would occur on Maui island. Figure 19 shows the planned capacity additions, distributed generation, storage, and synchronous condensers in Maui County.

Figure 19. PSIP near-term resource plan summary for Maui County (Maui, Lanai, and Molokai Islands)

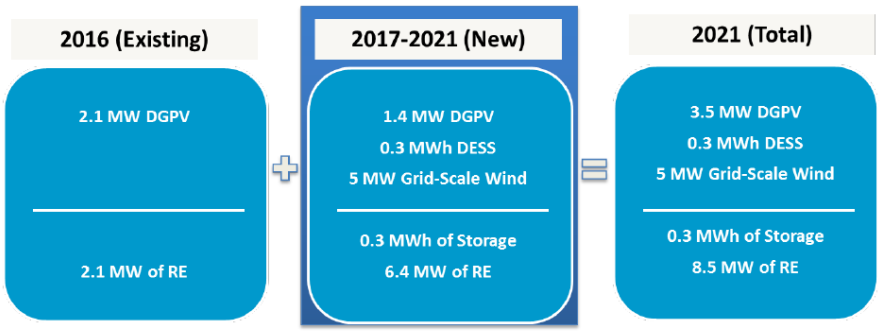


Maui

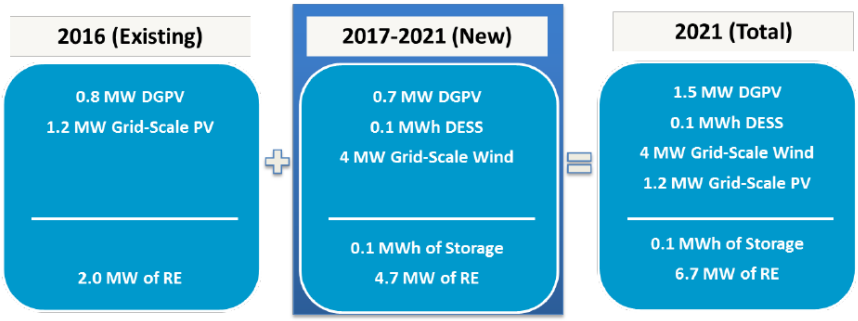


Molokai

[37] The HECO Companies. *PSIP Update Report*. December 23, 2016. Book 1. Page 6-11.



Lanai



Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 1. Pages 6-13 – 6-19 (pages 166-172 of pdf)

The most significant new installation in Hawaii County is load shift battery energy storage system ("BESS") which is about 48 MW in total by 2021. Moreover, there will be an additional 30.3 MW of DGPV, 22 MW of grid-scale wind, 5.7 MW of FIT, and 1 MW of grid-scale PV in the next five years.[38] Similar to Maui County, DGPV will increase significantly (about 34%) in Hawaii County, however, unlike Maui County, grid-scale wind will have the most significant increase (about 71%) in Hawaii County.

It should be noted that this plan might change. As the HECO Companies mentioned in the PSIP, "*the resource size and timing are not absolute and are subject to change, depending on specific conditions at the time applications are submitted to the Commission for approval and upon obtaining Commission approval*."[39]

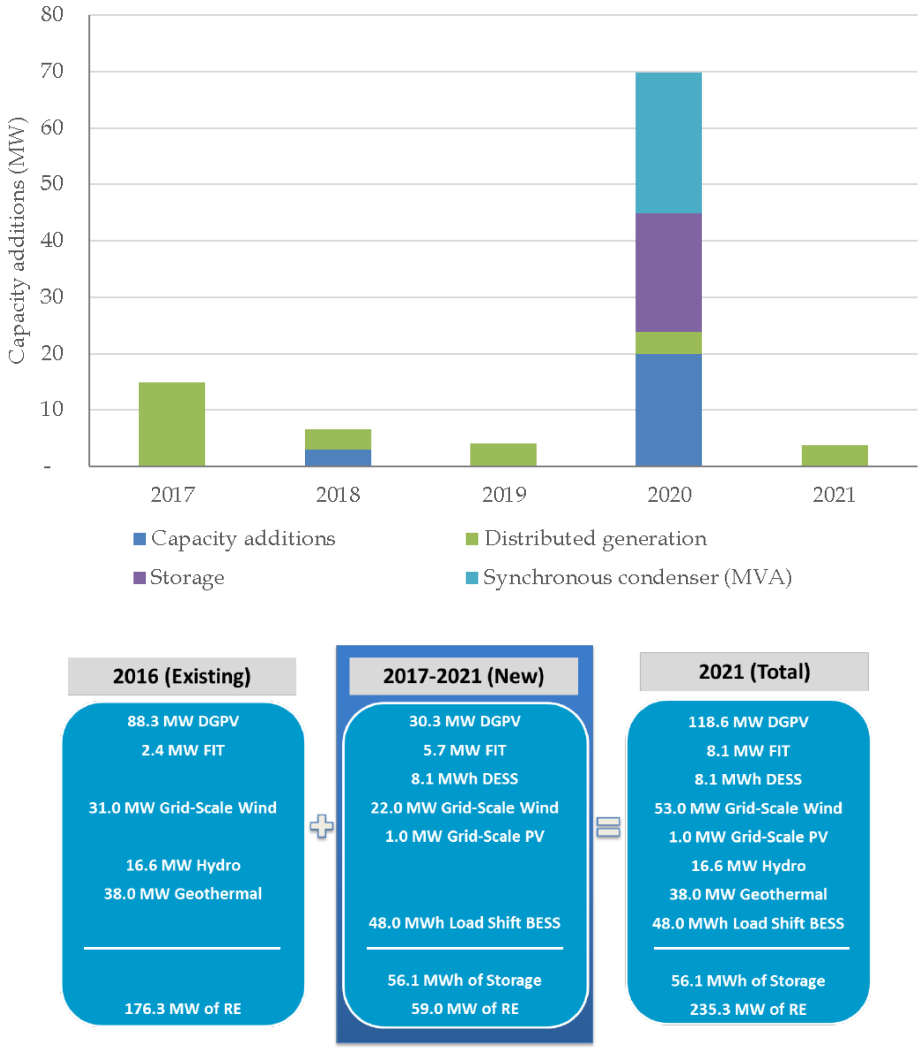
As for KIUC, there are 31 MW of new resources under construction or permitting, including 6 MW of hydro (Gay & Robinson, Olokele), 20 MW of grid-scale solar (AES Lawai), and 5 MW of customer solar. In addition, there are 24 MW of new resources under consideration, including 12

[38] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 1. Page 6-20 – 6-21.

[39] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 1. Page 163.

MW of Westside Pumped Hydro Storage and 12 MW of solar plus storage.[40] This will increase the total renewable energy in Kauai to 138.9 MW by 2025.[41]

Figure 20. PSIP near-term resource plan summary for Hawaii County



Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 1. Pages 6-20 – 6-21 (pages 173-174 of pdf).

[40] KIUC. *Renewable Energy Projects*. Website. Access date: October 3, 2017. <http://website.kiuc.coop/content/renewable-energy-projects>

[41] Ibid.

4.1.2 Retirements

As mentioned in the PSIP, according to E3 Plans[42] in Hawaii County, Puna Steam (15.7 MW), Hill 5 (13.5 MW) and Hill 6 (20.2 MW) will be retired in 2020.[43] Each of these three units are oil-fired plants. Honolulu County and Maui County do not have any announced generation plant retirements from 2017 to 2021 stated on the PSIP, although there are some thermal plants that are already over 40 years old as discussed in Section 3.2. The long-term retirement plans (beyond 2021) are discussed in Section 5.2.1.

As for KIUC, it has not released any near-term retirement plan for its generation plants as of October 2017.

4.2 System improvements planned: grid[44]

With the State's clean energy goals, aging transmission infrastructure, increasing load forecasts, and anticipated entry of more DERs, the HECO Companies and KIUC recognized the need to improve the transmission system. More specifically, there are some plans to expand the transmission system in Honolulu and to upgrade some of the components of the transmission assets to ensure that the grid is ready to provide access to other flexible power resources and accommodate the changes in the system.

4.2.1 Transmission expansion

To interconnect the planned large amounts of grid-scale renewable resources in the long term, new transmission and transmission upgrades will be necessary. The HECO Companies noted in the PSIP that in the near term they already have started to facilitate the first steps for the build out of the new transmission on all islands, as "*development of transmission lines require substantial lead-time.*"[45] Transmission expansion could take between 10-15 years as "*[n]ew transmission lines are site specific and dependent upon the specific location and size of a future grid-scale resource,*" and therefore involve "*many permitting, routing, and community issues.*"[46]

In Honolulu County, based on NREL-identified renewable potential analysis, the Honolulu County sub-transmission system will reach its capacity for interconnecting grid-scale solar and wind resources during the near-term action plan.[47] The HECO Companies stated in the PSIP that

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[42] Includes "E3 Plan," "E3 Plan with LNG," "E3 Plan with LNG; Keahole & HEP LNG Conversion."

[43] HECO Companies. *PSIP Update Report*. December 23, 2016. Book 3. Page M-8.

[44] Grid improvements planned by KIUC is not available online. LEI has sent a data request to KIUC and will update this section accordingly if the plan is provided by KIUC.

[45] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 1. Page 7-9.

[46] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 1. Page 7-9.

[47] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 1. Page 7-9.

they will evaluate the transmission upgrade projects in Honolulu County against alternatives, such as co-location of energy storage and interisland transmission, noting uncertainties regarding "*the practicality of maximizing NREL stated resource potentials, and the future system loads and its shape*."[48]

Below are the identified transmission projects in Hawaii County.[49] The PSIP document also identified several transmission system upgrade projects for Maui County after 2021, which is discussed in Section 5.3.1 Transmission upgrade:

- ***6800 Line Reconductor, Phases 2 through 4 (already approved by HPUC):*** a 69-kV transmission line from Keamuku switching station to Keahole switching station; needed to replace 21 miles of aged and deteriorated transmission poles, insulators, and hardware along Mamalahoa highway to improve the reliability of the aging infrastructure; and Phase 2 and 3 were completed in 2016, phase 4 will be completed in 2017.

- ***Kilauea 3400, Phases 1 through 4:*** a 34-kV transmission line from Puna Power Plant to Kilauea switching station; needed to be replaced aged and deteriorated sub-transmission poles, insulators, and hardware along Hawaii Belt road to improve the reliability of the aging infrastructure; replacement will take place in 2016-2017, Phase 1 will be implemented in 2017, phases 2 and 4 in 2018, and phase 3 in 2019.

- ***New 9400 Transmission Line, Phases 1 and 2:*** a new 69-kV transmission line from Waimea/Ouli area to North Kohala; will help facilitate the eventual rebuild of the 3300 line which is presently a radial line; reconducting work targeted for 2019-2020.

- ***6200 Transmission Line Rebuild:*** the 69-kV transmission line along the saddle road from Kaumana Switching station to Keamuku Switching station; needed to improve reliability of critical cross-island transmission line, and potentially to support additional East Hawaii generation; reconducting work rescheduled to 2020-2021.

KIUC also has plans to upgrade its transmission and distribution network in the near term. KIUC's 2017 Capital Improvements Program included the following projects (exceeding $1 million), which will provide member and environmental satisfaction and will accommodate future growth on the island:[50]

- ***Koloa Bess Repowering (2017):*** replace existing Advanced Lead Acid batteries with Lithium-ion for a total cost of about $1,600,000.

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[48] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 1. Page 7-9.

[49] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 1, page 7-29.

[50] KIUC. *2017 Capital Improvements Program for Ensuing Five Years*. December 27, 2016.

- ***GT-2 as Synchronous Condenser (2018):*** Unit GT-2 at the Port Allen Generation Station ("PAGS"). This construction will allow operation of the generator without its prime mover. The total cost is about $1,200,000.

- ***Lower Waiahi Penstock Replacement (2019):*** replace the 800-foot penstock with a lined steel pipe of an 800 kW Waiahi Lower Hydro power plant. The total cost is about $1,500,000.

- ***KPS Propane Modification (2018):*** installation of G.E.'s manifold ring around the gas turbine and build-out of an on-site propane receiving terminal with dedicated bullet tanks and vaporization system. The total cost is about $8,500,000.

- ***SCADA Upgrade (2017):*** The EMS/SCADA system, a major component of KIUC's operating systems, requires upgrades of main servers, offsite backup servers, workstations, and support hardware. The total cost will be about $1,485,000. And this upgrade will allow KIUC to leverage support and extend the system's next life cycle.

- ***Anahola Service Center (2017-2018):*** construction of a new KIUC service center in Anahola, including office space, garage, warehouse and outside material yard. This service center resides adjacent to the KIUC Renewable Solutions I solar field. This facility will serve the East and North Shore population. The total cost will be about $6,370,000.

Furthermore, on August 14, 2017, KIUC filed its DER management proposal with the PUC. Although it does not involve any additional investments or system improvements, the DER management proposal was designed to "*strike a reasonable and prudent balance between preserving the safety and reliability of KIUC's grid, while at the same time, encouraging the deployment of new DER options.*"[51] It is proposed to revise KIUC's current Schedule Q rate schedule and create two options: *Customer Self-Supply* and *Smart Export*, to replace current Non-Export and Export options. By revising this rate schedule, KIUC aims to "*accept more distributed energy resources onto the grid at the time of the day when it is most needed.*"[52]

4.2.2 Grid modernization

Considering the increasing adoption of DER, the HECO Companies have prepared grid modernization plans as directed by the PUC. These plans present a near-term roadmap for grid modernization from 2018 to 2023 in its "Modernizing Hawaii's Grid for Our Customers" (or "Grid Modernization Strategy" document).[53] The goal in the near term is to integrate "*advanced*

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[51] KIUC. *KIUC's Comprehensive Proposal to Address Decision and Order No. 34534 Issues: Proposed New Smart Export, Self-Supply, and Legacy Schedule Q Options and Corresponding Interconnection Standards and Requirements Exhibit 1. Docket No. 2014-0192.* Page 12 of 12.

[52] KIUC. *KIUC Files Proposal to Manage Distributed Energy Resources (DER) with the PUC Additional Future Rate Changes Likely.* August 14, 2017.

[53] As directed by the Hawaii Public Utilities Commission, HECO Companies developed the detailed Grid Modernization Strategy for stakeholder review and comment by June 30, 2017 and a final document filed with

grid technologies into the distribution system to enable cost-effective DER integration and utilization."[54] Figure 21 shows the near-term field deployments by operating company.

Customer-facing technologies include advanced meters together with related software systems, including head-end data collection system and meter data management system ("MDMS"). Honolulu, Maui, and Hawaii counties would need about 164,000 advanced meters in total from 2018 to 2023.[55] According to the HECO Companies, the installation of enterprise software will be "*more cost-effective perhaps by 2021*", so before that the Companies plan to use "*a hosted Software as a Service option for the head-end and MDMS at the beginning.*"[56]

As for sensing and measurement, 2,200 of faulted circuit indicators ("FCIs") will be installed in Honolulu, Maui and Hawaii counties, about 60% of which would be in Honolulu county. Distribution transformer measurement devices or line sensors will be installed as well. About 5,200 of Grid 20/20 will be installed in counties served by the HECO Companies.[57]

In addition, the HECO Companies plan to deploy field operational communications in 2019 and establish a single network operations center in 2019 to manage the network on all islands served.[58] To support the operational systems, a distribution management system ("DMS") and an enhanced outage management system ("OMS") will be installed by early 2021. On the distribution side, intelligent switches will be deployed beginning in 2019 for outage improvement, and from 2021 and beyond the focus will shift to "*reliability improvements and increasing operational flexibility for use of export DER.*"[59] Secondary var controllers will be utilized starting in 2018 to address voltage violations, especially for those circuits with significant DER adoption. Data integration and data storage will be on enterprise system by leveraging the existing service bus and exploring the use of cloud based data warehouse.[60]

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the PUC by August 29, 2017. On February 7, 2018, the PUC approved the proposed Grid Modernization Strategy for implementation subject to the directives, conditions, and guidance contained in the Order.

[54] HECO. *Modernizing Hawaii's Grid for Our Customers*. August 2017 Draft Report. Page 18.

[55] Ibid. Page 107.

[56] HECO Companies. *Modernizing Hawaii's Grid for Our Customers*. August 2017. Page 104.

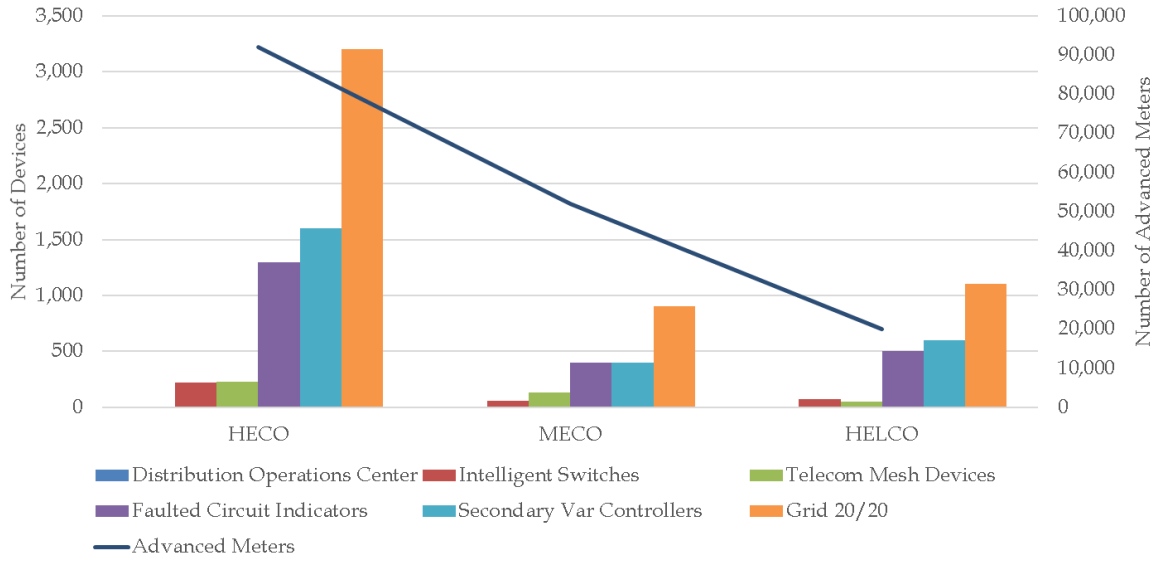
[57] Ibid.

[58] Ibid.

[59] Ibid. Page 106.

[60] Ibid. Page 107.

Figure 21. Near-term field deployments by operating company



Source: HECO Companies. Modernizing Hawaii's Grid for Our Customers. August 2017 Draft Report. Pages 107.

Furthermore, the HECO Companies will deploy autonomous resources like the IEEE 15-47-compliant advanced inverters[61] as well as other resources shown in Figure 22 below. This is to address the issue of system loss of voltage control. With its plan to integrate large quantities of variable wind and solar, traditional conventional central station generation will be displaced. However, the decommissioning of these conventional generators will result in "system loss of voltage control, short-circuit availability, inertia, and primary frequency response services."[62] Figure 22 enumerates the HECO Companies' plans to maintain operating reliability. These plans include employing synchronous condensers, fast frequency response resources, demand response resources to address frequency support, and utilizing synchronous condensers and storage systems to provide voltage support/short circuit availability.

[61] Ibid.

[62] Ibid. Page 82.

Figure 22. The HECO Companies' strategies for maintaining operating reliability

Issue	Current Methods	Future Methods
Frequency Support	Inertia is the stored rotating energy in a power system provided by online synchronous and induction generation operating at least at their minimum power output level. Primary frequency response (droop) is the automatic corrective response of the system, typically provided by synchronous generation, to react or respond to a change in system frequency. Spinning reserve is typically provided by synchronous generation that is ready to ramp up or down in response to a frequency deviation. Demand response is the reduction of load to balance loss of generation triggered at a predetermined frequency set point and limited by program participants. Underfrequency load shed scheme is the automatic disconnection of blocks of load to rebalance the system during a frequency disturbance.	Synchronous condensers and flywheels to provide inertia. Fast frequency response resources such as batteries, flywheels, curtailed PV, and wind energy that can respond in cycles, upwards, by injecting energy into the grid. Demand response resources (with fast frequency response characteristics) that can respond within a specified time adequate to correct frequency imbalances. This can include reductions in load or injection of real power from DER aggregated into a controllable and quantifiable program to respond to underfrequency events, or a fast injection of controllable load in response to an overfrequency event. Autonomous downward response of inverter-based DER resources configured with the advanced inverter frequency-watt function to respond to an overfrequency event.
Voltage Support/Short-Circuit Availability	Reactive power supply and voltage control provided by synchronous generating facilities, excitation systems, and capacitors. Protective relay schemes designed to isolate faults within cycles. Fault current supplied by synchronous generators. Dynamic reactive power capability of synchronous generators and secondary var controllers.	Synchronous condensers to provide reactive power support and short-circuit current. Repurposing deactivated generators as condensers. Storage systems such as battery storage, electric vehicles, flywheels, and thermal storage to provide quick and flexible energy sources to stabilize system balancing.

Source: HECO Companies. Modernizing Hawaii's Grid for Our Customers. August 2017 Draft Report.

4.3 System improvements planned: others

As shown in summaries of the near-term plans for the islands above, in addition to generation capacity as well as distributed generation, the HECO Companies also planned additional frequency response capabilities in the form of storage and synchronous condensers. As the HECO

Companies increase the amount of renewable energy production, energy storage will play an important role in distributing that energy throughout the day to coincide with demand, and to provide grid services such as fast-frequency response or contingency reserves. The HECO Companies already included these system improvements in the plan in the near term, and stated in their PSIP that they will continue to evaluate and to pursue various storage capabilities, including DESS to facilitate DER integration and other storage options.

Figure 23. System security additions during near-term resource plans

	O'ahu	Maui	Lanai	Molokai	Hawaii
Contingency FFR1	2019	2019	2019	2019	2020
1-hour regulation BESS	2020				
Sychronous condensers	2021	2020	2019	2019	2020
Load-shifting energy storage					2020

Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 1, pages 6-10 – 6-21. Pages 163-174 of pdf.
Note: FFR1 = Fast Frequency Response 1; BESS = battery energy storage system ("BESS").

5 System improvements for the subsequent years through 2045

5.1 System evaluation

Similar to Section 4.1, this Section presents key factors that impact system improvements needed, including the RPS goals and load forecasts from 2022 through 2045. Same as its near-term goals, the HECO Companies expect to achieve the RPS goal ahead of schedule, which requires more renewable resources to be added to the system. Moreover, the grid needs to be improved to accommodate these resources. In addition, forecasted load growth in Maui County and Hawaii County requires additional resources and reliable grid as well.

5.2 System improvements planned: generation

There are a number of long-term scenarios that the HECO Companies have outlined through their extended analyses in the PSIP. Figure 24 summarizes the long-term plans for each island under the HECO Companies.

Figure 24. PSIP long-term plans by the HECO Companies and islands

	HECO	MECO - Maui	MECO-Lanai	MECO-Molokai	HELCO
Post-April PSIP Plan	x	x			x
E3 Plan	x	x			x
E3 Plan with LNG	x	x			x
E3 Plan with Generation Modernization	x				
E3 Plan with LNG and Generation Modernization	x				
100% renewable by 2020			x	x	
100% renewable by 2030			x	x	

Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 1. Page 2-10 – 2-12.

The PSIP document explained the plans[63] as follows:

- ***Post-April PSIP Plan:*** developed by the HECO Companies after the filing of the April 2016 PSIP utilizing updates to assumptions that were made after the April 2016 filing;
- ***E3 Plan:*** This plan is based on an optimized resource portfolio utilizing E3's RESOLVE model,[64] including "optimal" retirements, with adjustments to the plan made to reflect actual resource option sizes and additional modeling using consultant Ascend Analytics' sub-hourly analysis and the Companies' analysis using the PLEXOS sub-hourly model. This plan did not include LNG as a potential fuel source;

[63] HECO Companies. *PSIP Update Report*. December 23, 2016. Book 1. Page 2-10 – 2-12.

[64] Energy and Environmental Economics (E3) employed their RESOLVE capacity expansion modeling tool to conduct the base analysis for HECO Companies' December 2016 PSIP update.

- ***E3 Plan with LNG:*** This plan was developed in the same way as the E3 Plan, except LNG was made available as a potential fuel source and the optimization models were allowed to "choose" LNG to the extent it was determined by the model to be the optimum fuel choice;

- ***E3 Plan with Generation Modernization:*** This plan was developed in the same way as the E3 Plan. However, retirements and replacement generation as recommended by the Companies' Power Supply group were added into the model. LNG was not available as a fuel source in this plan;

- ***E3 Plan with LNG and Generation Modernization:*** This plan is the same as the E3 Plan with Generation Modernization. However, LNG was assumed to be available as a possible fuel source;

- ***100% renewable by 2020 (Molokai and Lanai):*** Optimized plans developed using the PLEXOS[65] optimization logic for 100% renewable energy in 2020; and

- ***100% renewable by 2030 (Molokai and Lanai):*** Optimized plans developed using the PLEXOS optimization logic for 100% renewable energy in 2030.

Instead of providing a preferred plan, the HECO Companies presented these resource plans as different paths to achieve the RPS goals. Nevertheless, these plans would still add between 1,570 and 2,310 MW of renewables by 2045. This means that it is inevitable to bring large amounts of renewables online, no matter which plan is chosen.

5.2.1 New plant installations[66]

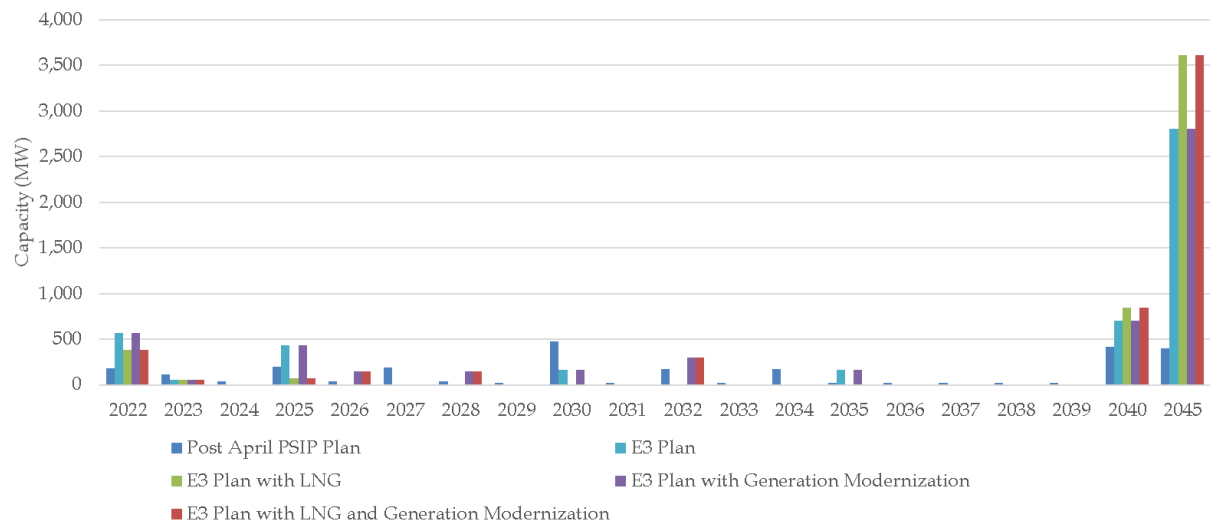
PSIP presented new installations under different plans. These new installations range between 2,848 and 5,821 MW from 2022 to 2045, depending on the plan. "Post-April PSIP Plan," "E3 Plan," and "E3 Plan with LNG" are all examined for each county, while two additional plans - "E3 Plan with Generation Modernization" and "E3 Plan with LNG and Generation Modernization" - are only studied for Honolulu County. For all the counties served by the HECO Companies, E3 Plans with LNG[67] always require more new installation than other plans from 2022 to 2045. New installation under the "Post-April PSIP Plan" is much less than (only about 30% to 50% of) the new capacity under E3 Plans.

[65] HECO Companies' Advanced Planning Department used PLEXOS for Power Systems to conduct hourly and sub-hourly production simulation modeling analysis of the Core Cases developed by E3.

[66] This section is based on data from PSIP Book 1. Only new installation (not fuel conversion or retirement) is included in the discussion.

[67] "E3 Plan with LNG and Generation Modernization" for Honolulu county.

Figure 25. New installation in Honolulu County under different plans



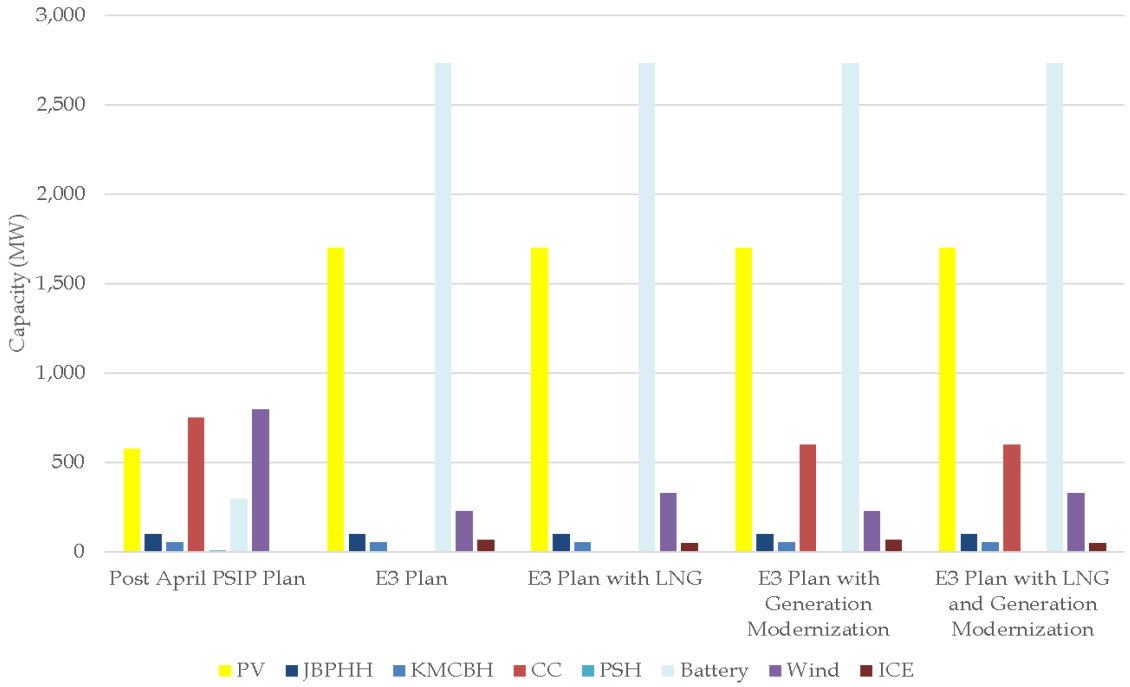
Note: storage included
Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 1. Page 4-3 – 4-7.

In Honolulu County, compared with other plans, "E3 Plan with LNG and Generation Modernization" requires the newest installation in terms of capacity – about 5,575 MW from 2022 to 2045.[68] In contrast, the "Post-April PSIP Plan" needs only 2,599 MW of new installation through the period, which is about half the capacity planned in "E3 Plan with LNG and Generation Modernization."

As shown in Figure 25, all of the E3 plans allocated the maximum new installation to 2045, especially "E3 Plan with LNG." In this plan, new installation in 2045 takes up 73% of the total new installation throughout the period. Different from E3 Plans, the maximum capacity of new installation is in 2030 in the "Post-April PSIP Plan." As for types of new installation, grid-scale PV and 4-hour load-shift battery are the major new installations in all E3 Plans, while new wind takes the largest share in "Post-April PSIP Plan."

[68] HECO Companies. *PSIP Update Report*. December 23, 2016. Book 1. Page 4-3 – 4-7.

Figure 26. New installation in Honolulu County by fuel type



Note: JBPHH: Joint Base Pearl Harbor-Hickam, KMCBH: Kaneohe Marine Corps Base Hawaii, PSH: pumped storage hydro, ICE: internal combustion engine.
Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 1. Page 4-3 – 4-7.

In Maui County, there is no new installation in Molokai or Lanai from 2022 to 2045. All the new installations discussed below are in Maui island. Compared with other plans, "E3 Plan with LNG" requires the newest installation in terms of capacity – about 579 MW from 2022 to 2045.[69] In contrast, the "Post-April PSIP Plan" needs only 169 MW of new installation through the period, which is less than 30% of the capacity planned in "E3 Plan with LNG."

As shown in Figure 27, all of the E3 plans allocated the maximum new installation to 2045, especially "E3 Plan with LNG." In this plan, new installation in 2045 takes up 75% of the total new installation throughout the period. Different from E3 Plans, the maximum capacity of new installation is in 2022 in the "Post-April PSIP Plan." As for types of new installation, grid-scale PV and 4-hour load-shift battery are the major new installations in all E3 Plans, while biomass and 4-hour load-shift battery take the largest share in "Post-April PSIP Plan."

[69] HECO Companies. *PSIP Update Report*. December 23, 2016. Book 1. Page 4-11 – 4-23.

Figure 27. New installation in Maui County under different plans

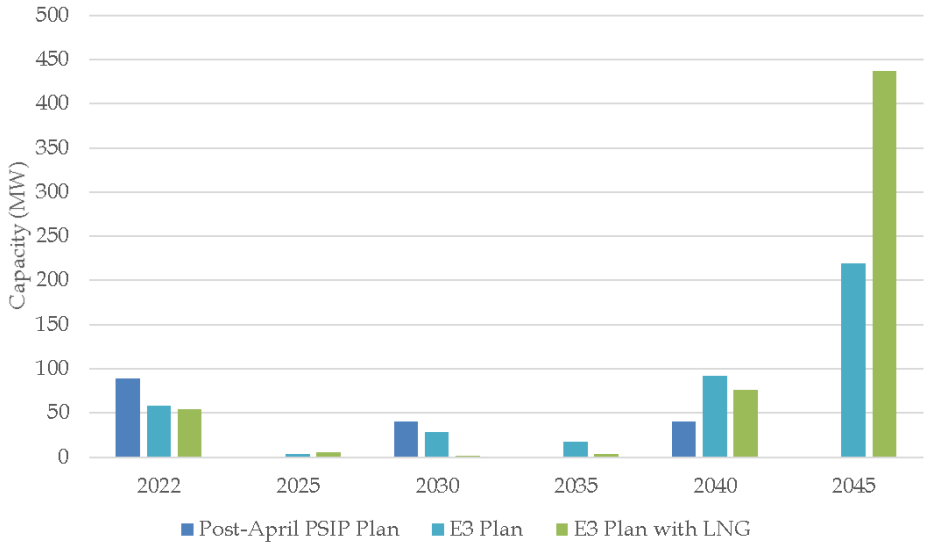
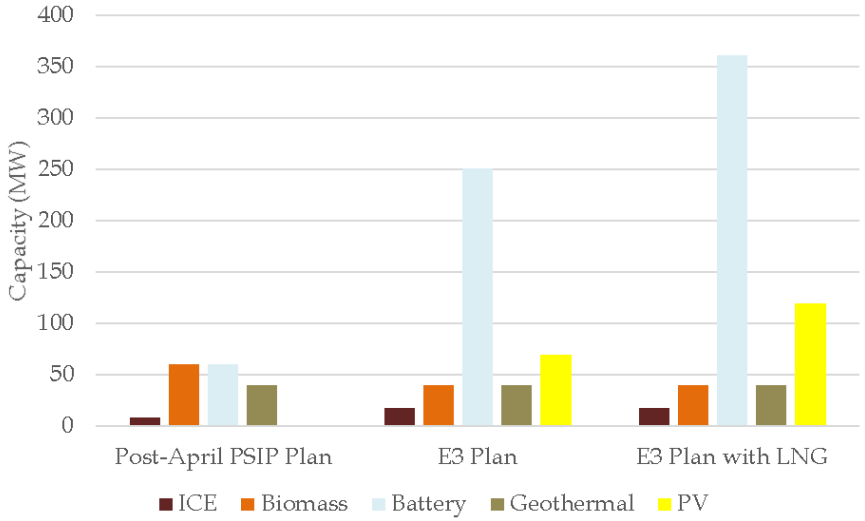


Figure 28. New installation in Maui County by fuel type



Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 1. Page 4-11 – 4-23.

In Hawaii County, new installation ranges between 80 and 271 MW from 2022-2045, depending on the plan. The "E3 Plan" and "E3 Plan with LNG" require the same amount of new installation – about 271 MW from 2022 to 2045, but they have different allocations in each year.[70] In contrast, the "Post-April PSIP Plan" needs only 80 MW of new installation through the period, which is less than 30% of the capacity planned in either of the E3 Plans. As shown in Figure 29, all the E3 plans allocated the maximum new installation to 2045, especially "E3 Plan with LNG." In this

[70] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 1. Page 4-11 – 4-23.

plan, new installation in 2045 takes up 62% of the total new installation throughout the period. Different from E3 Plans, the maximum capacity of new installation is in 2030 in the "Post-April PSIP Plan." As for types of new installation, there is 30% of wind and 70% of 4-hour load-shift battery in both of the E3 Plans, while geothermal take half of the new capacity and the rest half is shared by biomass and wind evenly in "Post-April PSIP Plan."

Figure 29. New installation in Hawaii county under different plans

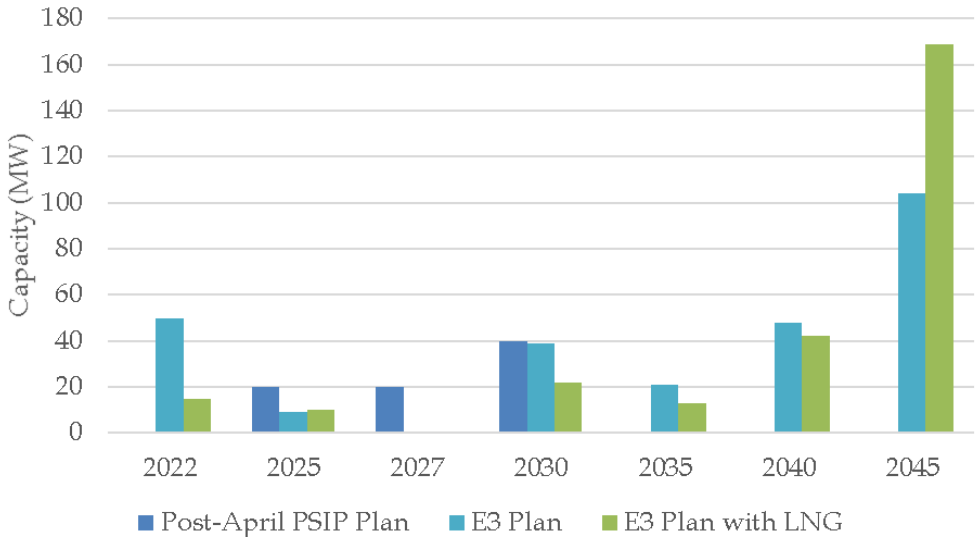
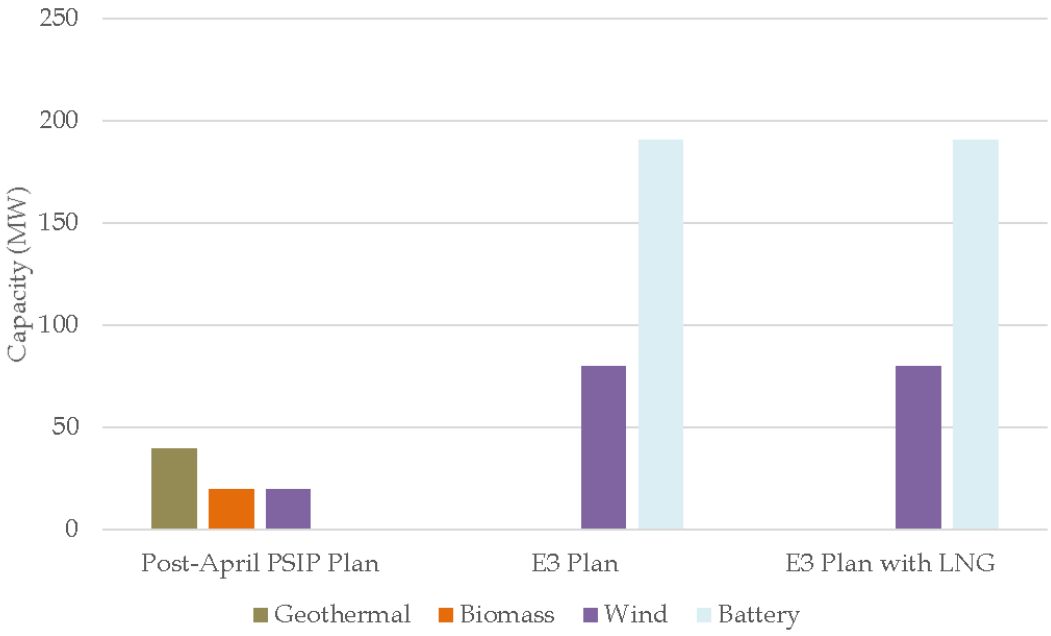


Figure 30. New installation in Hawaii County by fuel type



Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 1. Page 4-25 – 4-27.

5.2.2 Retirements

Similar to the new additions, the PSIP also has laid out various scenarios for generation retirements. According to PSIP, from 2022 to 2045, E3 Plan (or "E3 Plan with Generation Modernization" for Honolulu County) has the largest projected retirements in terms of net capacity – around 1,287 MW in Honolulu, Maui, and Hawaii counties. In addition, there will be about 1,262 MW of retirements under E3 Plan with LNG (or "E3 Plan with LNG and Generation Modernization" for Honolulu County and "E3 Plan with LNG, Keahole & HEP LNG Conversion" for Hawaii County). "Post April PSIP Plan" will see the least amount of retirements – about 1,239 MW of net capacity. In all these scenarios, the anticipated retirements from 2022 to 2045 range between 1,239 and 1,287 MW.

Figure 31. Potential retirements in Honolulu County under different plans

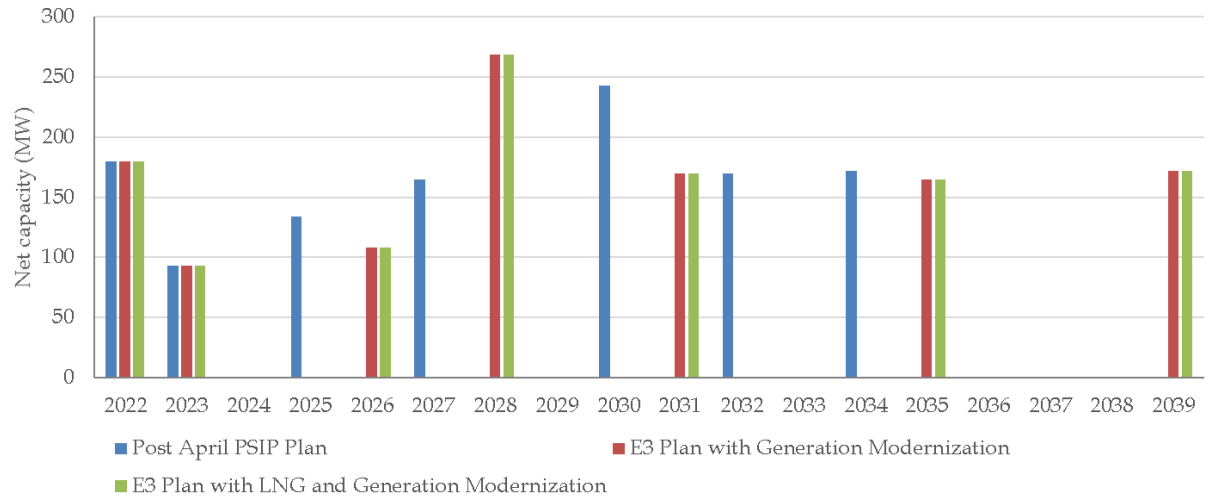


Figure 32. List of potential retirements in Honolulu county

Unit	Fuel	Net capacity (MW)	Age as of 2016	Delivery type	Retirement year		
					Post April PSIP Plan	E3 Plan with Generation Modernization	E3 Plan with LNG and Generation Modernization
AES	Coal	180.00	25	Baseload	2022	2022	2022
Waiau 3	LSFO	47.00	70	Cycling	2023	2023	2023
Waiau 4	LSFO	46.50	67	Cycling	2023	2023	2023
Waiau 5	LSFO	54.50	58	Cycling	2030	2026	2026
Waiau 6	LSFO	53.70	56	Cycling	2030	2026	2026
Waiau 7	LSFO	83.30	51	Baseload	2032	2031	2031
Waiau 8	LSFO	86.20	49	Baseload	2032	2031	2031
Kahe 1	LSFO	82.20	54	Baseload	2027	2035	2035
Kahe 2	LSFO	82.20	53	Baseload	2027	2035	2035
Kahe 3	LSFO	86.20	47	Baseload	2034	2039	2039
Kahe 4	LSFO	85.30	45	Baseload	2034	2039	2039
Kahe 5	LSFO	134.60	43	Baseload	2030	2028	2028
Kahe 6	LSFO	133.80	36	Baseload	2025	2028	2028

Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 3. Page M-6; and Book 2. Page D-2.

In Honolulu County, about 1,156 MW of fossil fuel plants, including 180 MW of coal plant and 976 MW of oil-fired plants, will retire from 2022 to 2039. The average age of these units is 50 years as of 2016. The units that will retire are the same across different resource plans, although the retirement year of certain units will be slightly different.

In Maui County, retirements only occur in 2022 (34 MW of oil-fired units) under "Post April PSIP Plan." But in addition to that, both of "E3 Plan" and "E3 Plan with LNG" see retirement of diesel units (Maalaea units) in 2045 – about 84 MW and 59 MW respectively under each plan.

Figure 33. Potential retirements in Maui County under different plans



Figure 34. List of potential retirements in Maui County

Unit	Fuel	Net capacity (MW)	Age as of 2016	Delivery type	Retirement year		
					Post April PSIP Plan	E3 Plan	E3 Plan with LNG
Kahului 1	IFO	5.00	68	Peaking	2022	2022	2022
Kahului 2	IFO	5.00	67	Peaking	2022	2022	2022
Kahului 3	IFO	11.50	62	Baseload	2022	2022	2022
Kahului 4	IFO	12.50	50	Baseload	2022	2022	2022
Ma'alaea 4	LSD	5.60	43	Peaking	N/A	2045	2045
Ma'alaea 5	LSD	5.60	43	Peaking	N/A	2045	2045
Ma'alaea 6	LSD	5.60	43	Peaking	N/A	2045	2045
Ma'alaea 7	LSD	5.60	38	Peaking	N/A	2045	2045
Ma'alaea 8	LSD	5.60	38	Peaking	N/A	2045	2045
Ma'alaea 9	LSD	5.60	38	Peaking	N/A	2045	2045
Ma'alaea 10	LSD	12.50	36	Cycling	N/A	2045	2045
Ma'alaea 11	LSD	12.50	36	Cycling	N/A	2045	2045
Ma'alaea 12	LSD	12.50	28	Cycling	N/A	2045	N/A
Ma'alaea 13	LSD	12.50	28	Cycling	N/A	2045	N/A

Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 3. Page M-9; and PSIP Book 2. Page D-18.

In Hawaii County, a total of between 14 and 49 MW are going to be retired, depending on the plan. About 49 MW of oil-fired units will retire from 2025 to 2030 under "Post April PSIP Plan." But under E3 Plans, including "E3 Plan," "E3 Plan with LNG," and "E3 Plan with LNG; Keahole & HEP LNG Conversion," these oil-fired units will be retired in 2020, and Keahole CT2 will be retired in 2040 if a replacement black-start resource is added to West Hawaii.

Figure 35. Potential retirements in Hawaii County under different plans

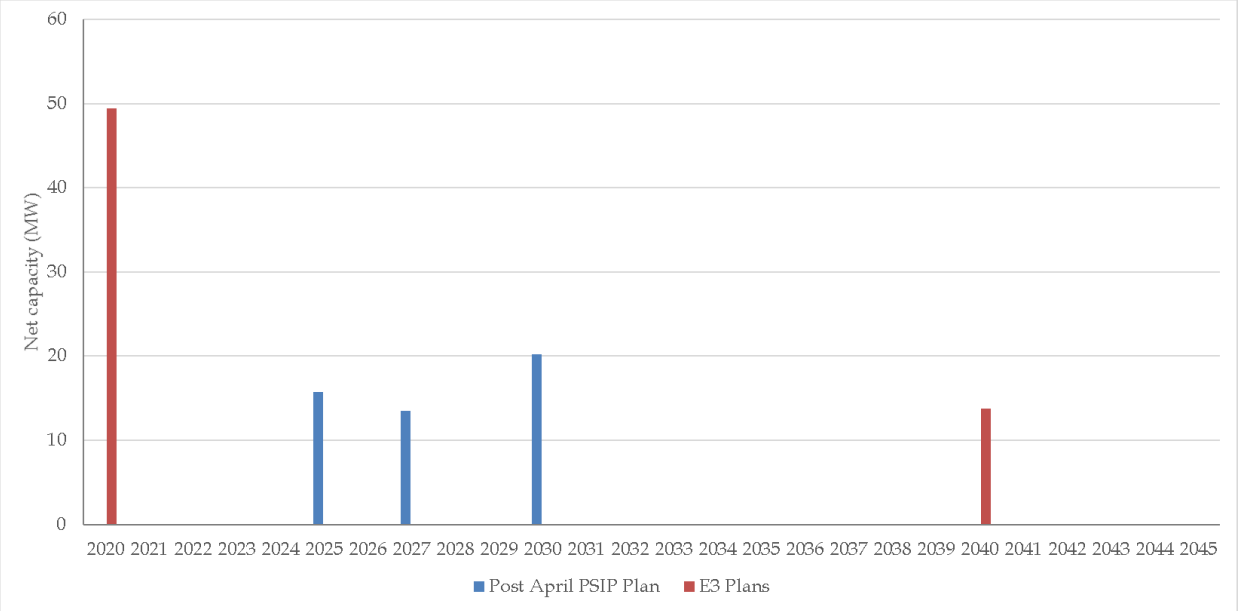


Figure 36. List of potential retirements in Hawaii County

Unit	Fuel	Net capacity (MW)	Age as of 2016	Delivery type	Retirement year			
					Post April PSIP Plan	E3 Plan	E3 Plan with LNG	E3 Plan with LNG; Keahole & HEP LNG Conversion
Puna Steam	IFO	15.70	46	Frequency Regulation, Load Following, Cycling	2025	2020	2020	2020
Hill 5	IFO	13.50	51	Frequency Regulation, Load Following, Cycling	2027	2020	2020	2020
Hill 6	IFO	20.20	42	Frequency Regulation, Load Following, Cycling	2030	2020	2020	2020
Keahole CT2	LSD	13.80	27	Peaking, Emergency, Black start	N/A	2040	2040	2040

Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 3. Page M-8; and PSIP Book 2. Page D-27.

5.3 System improvements planned: grid[71]

5.3.1 Transmission upgrade

Central Maui transmission line upgrade project

One of the major transmission projects in Maui in the long term is the Central Maui Transmission Line Upgrade Project. This project is being driven by the retirement of the Kahului Power Plant.

[71] KIUC's grid improvements plan is not available online. LEI has sent out a data request to KIUC, and will update this section accordingly if such plan is provided by KIUC.

As mentioned in section 5.2.1, in 2024, MECO-Maui must retire the 4-unit, 35.92 MW, industrial fuel oil ("IFO")-fueled, Kahului Power Plant ("KPP") in order to comply with mandatory National Pollution Discharge Elimination System ("NPDES") requirements related to cooling water discharge.[72] As a result of the KPP retirement, PSIP analyses showed a shortfall of dispatchable renewable generation. KPP also provides voltage support for Central Maui, and fault current for the 23-kV system; and therefore, the Central Maui Transmission Line Upgrade project will be needed for voltage control and to accommodate projected growth in the South Maui area.[73] The HECO Companies stated in the PSIP that "*[s]ince any replacement generation will be relocated from KPP, upgrades to the Central Maui transmission line must be in place and a synchronous condenser must be installed on the 23 kV system before KPP is retired*."[74]

This transmission project will consist of three parts:[75]

- Maalaea–Puunene Substation reconductoring;
- Maalaea to Waiinu Substation 69 kV reconductoring; and
- Waiinu to Kanaha 23 kV to 69 kV upgrade.

The PSIP describes the NTA analysis, considering internal combustion distributed generation ("DG"), BESS, demand response ("DR"), and synchronous condensers, as an option to offset the need for the transmission project, and that they will evaluate aggregated DR as an NTA as well. To follow a competitive procurement process, a docket was filed with HPUC in May 2016 regarding soliciting proposals for NTAs.[76]

5.3.2 Interisland transmission

Interisland transmission is only evaluated in this section, as this requires many years to develop and will not have an impact on near-term action plans in the PSIP.[77] It is noted in the PSIP that construction and operation of interisland transmission cables are technically feasible, "*commercially available with operating installations around the world, and financially feasible in capacity markets*."[78]

However, the installation of interisland transmission faces challenges of benefits and costs comparison, social acceptance, and political will. The Docket 2013-0169 on whether interisland cables were in the public interest was opened in 2013, but it has been inactive for a while. In the

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[72] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 3. Appendix M. Page M-9.

[73] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 1. Page 7-22.

[74] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 1. Page 6-9.

[75] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 1. Page 7-22.

[76] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 1. Page 7-22.

[77] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 3. Page H-54

[78] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 3. Page H-51.

2014 PSIP, the HECO Companies evaluated the interconnection between Oahu and Maui island, but found that the gross benefits were "*substantially less than the estimated cost of a cable*."[79] In December 2016 PSIP, the HECO Companies evaluated again the interisland transmission between Oahu, Maui, and Hawaii Island by conducting break-even analysis. This analysis assumes various copper plate configurations, and then compares the benefits against $600 million. According to E3 Copper-plate Plans, the present value benefit of the cable is $3 billion, which is "*sufficiently large enough to justify further analysis of the feasibility, configuration and cost effectiveness of interisland interconnections*".[80] PSIP also noted that "*this is an upper bound that will be refined when cable operating constraints and adjusted system operating constraints are developed through more detailed study.*"[81]

5.3.3 Grid modernization

As stated in the "Grid Modernization" document, in the long term, HECO aims to "*extend the integrated grid platform to leverage energy storage, advanced grid technologies, and cyber-physical infrastructure upgrades that can incrementally evolve over time*." In addition to the 100% renewable goal, such a grid would also "*create strong economic benefits for communities, businesses, and customers as well as the infrastructure owners.*"[82] However, the document focuses on the near-term approach for the next six years, as discussed in Section 4.2.2, but does not provide sufficient information about plans in the long term.

[79] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 3. Page H-53.

[80] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 1. Page 3-14.

[81] Ibid.

[82] HECO. *Modernizing Hawaii's Grid for Our Customers*. August 2017. Page 18.

6 Appendix A: Scope of work to which this deliverable responds

Task 1.1.5 Identification of system improvements planned for installation in the next five years proposed improvements needed through 2045.

CONTRACTOR shall identify system capital improvements needed and planned for installation in the next five years, and for the subsequent years through 2045, and which options would be specifically required to provide safe, reliable service to customers.

DELIVERABLE FOR TASK 1.1.5. CONTRACTOR shall provide its conclusions and all work to identify needed system improvements that are planned for the next five years and through 2045. CONTRACTOR shall include written narrative in MS Word, spreadsheets in MS Excel, as well as an index of all source information used to generate the deliverable. CONTRACTOR shall submit deliverable for TASK 1.1.5 to the STATE for approval.

7 Appendix B: Works Cited

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Review of potential stranded costs resulting from a change in utility ownership model in Hawaii

working paper prepared by London Economics International LLC for the State of Hawaii with support from Meister Consultants Group

September 25th, 2017

London Economics International LLC, together with Meister Consultants Group ("the Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State of Hawaii in achieving its energy goals. As part of the engagement, this working paper provides a discussion of the potential for stranded costs following a change in ownership for the utilities serving electric customers in Hawaii. Stranded costs are costs that utilities can recover through their rates but whose recovery may be hindered or averted due to competition in the industry or forced divestiture. In general, absent a change in a regulatory model that would introduce market-based constructs, all assets required to operate the island power grids would remain in the rate base, or remain under contract with the new entity which would then recover the contract costs from electric customers. Therefore, a change in ownership model without a departure from the current regulated regime is not expected to result in stranded costs which must be recovered from ratepayers.

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List of acronyms

ACC	Arizona Corporation Commission
APS	Arizona Public Service Company
B Corp	Benefit corporations
CMVE	Competitive Market Value Estimate
Co-op	Cooperative utility
CTC	Competitive Transaction Charge
DBEDT	Hawaii Department of Business, Economic Development, and Tourism
DER	Distributed Energy Resource
DRC	Debt Retirement Charge
EIA	US Energy Information Administration
FERC	Federal Energy Regulatory Commission
HECO	Hawaiian Electric Company, Inc.
HEI	Hawaiian Electric Industries, Inc.
HELCO	Hawaii Electric Light Company, Inc.
HERA	Hawaii Electricity Reliability Administrator
HSEO	Hawaii State Energy Office
IDER	Integrated DER
IESO	Independent Electricity System Operator
IOU	Investor-Owned Utility
IPP	Independent Power Producer
IRP	Integrated Resource Plan
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company, Ltd.
Munis	Municipal utilities
NMP	Nine Mile Point
NYSE	New York Stock Exchange
OEFC	Ontario Electric Financial Corporation
OPG	Ontario Power generation
PILOT	Payment in Lieu of Taxes
PPA	Power Purchase Agreement
PSIP	Power Supply Improvement Plans
PUC	Public Utilities Commission
RSE	Revenue Stream Estimate
SB	Single Buyer
SCO	Stranded Cost Obligation
TEP	Tucson Electric Power

1 Executive summary

London Economics International LLC, together with Meister Consultants Group (the "Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which corresponds to Task 1.1.6 in the project scope of work, provides a discussion of the potential for stranded costs following a change in ownership for the utilities serving electric customers in Hawaii.

1.1 Introduction to stranded costs

Stranded costs represent costs which a utility was allowed to recover through regulated rates, but the recovery of which may be impeded or prevented as a jurisdiction transitions from a regulated regime to a competitive, deregulated environment. Assets become stranded when a utility can no longer recover the costs incurred to acquire and operate these assets through the rate base. Historically, provided that the investments were prudent and verifiable (which they typically were if they had been subject to prior regulatory approval), utilities have been allowed to recover their stranded costs.

The calculation of stranded costs is a process which must include both economic and policy considerations. Several methods have been proposed by generation owners, economists, and regulators. These methods differ in a few key areas, namely by whether they measure stranded costs before or after the restructuring takes place, whether they are based on the estimation or on actual market valuations of assets, and whether they value a company's assets individually or take a more aggregate, "top-down" approach.

Several mechanisms have been used or proposed to allow utilities' recovery of their stranded costs. These mechanisms have different effects on different types of customers, from one-time exit fees to debt securitization or transitional surcharges on the electricity consumers.

1.2 Potential for stranded costs from new ownership models in Hawaii

In a previous working paper discussing potential ownership models for the utilities serving Hawaii's counties,[1] the Project Team introduced eight potential utility ownership models. These ownership models range from the traditional (such as Investor-Owned Utility ("IOU"), cooperative, municipal utility, or majority government-owned) to other models that would also require significant changes in the regulatory environment (such as Integrated Distributed Energy Resources ("IDER") or a single-buyer model).

Currently in Hawaii, all utility assets in all counties are included in their respective county rate base. While the bulk of utility assets are comprised of generation, transmission, and distribution assets, other categories such as real estate, inventory (for fuel, materials, and supplies), or

[1] Task 1.1.1./Task 1.2.1. Introduction of Ownership Models and Comparison of Ownership Models and How They Relate to the State's Key Factors.

"accounting" assets (such as investments related to employee pensions or deferred costs) are also included. In all cases, the utility assets, and power supply contracts, have been procured under the oversight of the Hawaii Public Utilities Commission ("PUC") and thus can be presumed to have been procured prudently and be necessary to the continued reliable operation of the power grid in each county.

Due to the unique characteristics of the state of Hawaii where each island operates an independent power grid, there are no existing alternative sources of power but those currently serving each county's load. As such, in the event of a change in ownership model of utilities, there would still be a need for these assets to ensure adequate supply and reliable transmission/distribution of power to customers.

Absent a change in the regulatory model that would introduce market-based constructs, all assets required to operate the power grid would remain in the rate base, or remain under contract with the new entity, which would then recover the contract costs from ratepayers. Therefore, a change in ownership model under the current regulated regime would not result in stranded costs which must be recovered from ratepayers.

Figure 1. Summary table of potential stranded costs for each ownership model

<table>
<tr><th>Ownership</th><th>Generation assets</th><th>Transmission/distribution ("T&D") assets</th></tr>
<tr><td>Traditional utility models:
- investor-owned utility ("IOU") (status quo or new owner),
- municipal utility ("muni"),
- cooperative (co-op), and
- hybrid - majority government owned ("hybrid")</td><td>No stranded costs</td><td>T&D assets remain under regulated regime, hence no stranded costs are expected</td></tr>
<tr><td>Integrated Distributed Energy Resources System Operator ("IDER")</td><td rowspan="2">Potential for stranded costs if generation assets have lower value under a new regulatory model than under current regulated regime</td><td rowspan="2">T&D assets remain under regulated regime, hence no stranded costs are expected</td></tr>
<tr><td>Single Buyer</td></tr>
<tr><td>Grid defection</td><td colspan="2">Technically no stranded costs would result as assets remain in rate base. However, there would be a growing number of assets no longer used and useful, resulting in growing costs being spent over smaller and smaller group of customers</td></tr>
</table>

Nevertheless, under the integrated distributed energy resources ("IDER") system operator and Single Buyer ("SB") models, a change in the regulatory structure is needed to create the framework to aptly compensate generation resources. Therefore, there is a potential for stranded costs if generation assets under the new regulatory structure have lower value. In general, thermal generation plants that are less than 30 years in age are more at risk of being stranded, as they may retain useful accounting life when made obsolete by a 2045 100% renewable mandate. The Project Team estimated that the Hawaii State utilities' thermal generation fleet has a net value of approximately $1,200 million, and identified approximately 400 MW of generation capacity

that is less than 30 years in age[2], a portion of which could potentially be a source of stranded costs with the change in ownership and regulatory structure to IDER system operator or SB. However, renewable generation is not expected to replace thermal generation overnight, so by the time each asset must be retired, the asset would have lost a portion of its value.[3]

In a follow-up work paper discussing potential changes in regulatory models,[4] the Project Team will discuss in more detail the potential for stranded costs for the various regulatory models, taking into consideration the ownership models introduced in this paper.

[2] Based on LEI's analysis of regulatory filings by the HECO Companies and KIUC.

[3] The annual straight-line remaining-life depreciation rates vary by generation asset accounts, but average approximately 2%.

[4] Task 2.2.4. Summary Analysis and Conclusions Related to Estimating Stranded Costs for Each Regulatory Model.

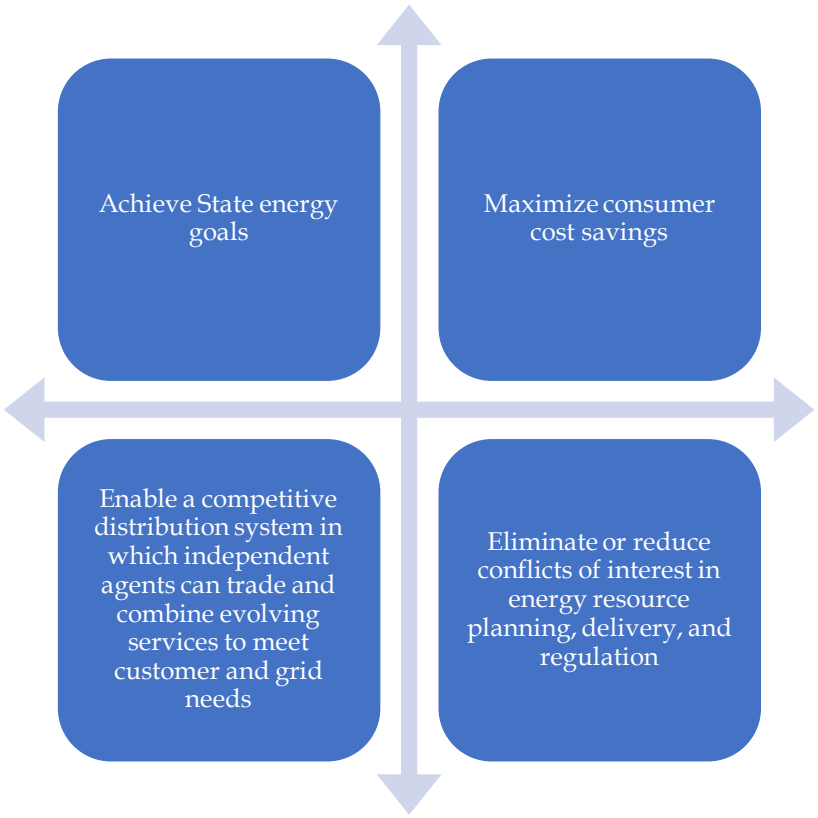
2 Introduction and scope

2.1 Project description

DBEDT was directed by the State's legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. The Project Team, through a competitive sealed proposals procurement,[5] was contracted to perform this study.[6]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[7] listed in Figure 2.

Figure 2. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

[5] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[6] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[7] House Bill No. 1700 Relating to the State Budget.

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[8]

2.2 Role of this deliverable relative to others in the project

This deliverable corresponds to Task 1.1.6. in the project scope of work. It builds on previous deliverables to discuss the potential for stranded costs related to the various ownership models introduced in the report for Task 1.1.1./Task 1.2.1., given the current regulated assets of the incumbent utilities. However, it is important to note that some utility ownership models cannot be considered in isolation from the regulatory framework in which they are embedded. A discussion of potential stranded costs in different regulatory environments will be the topic of a subsequent deliverable.[9]

2.3 Future refinements

This deliverable includes a discussion of the potential for stranded costs for the various utility ownership models introduced in the report for Task 1.1.1./Task 1.2.1., which provided an overview of the different utility ownership models. Since the results of the Project Team's analysis discussed in the previous deliverable are subject to further refinement and change as the project moves forward and inputs from the stakeholder groups and results of the quantitative analysis and case studies become available, the Project Team may make further refinements to the current report.

[8] Hawaii Contract No. 65595. Scope of Services.

[9] Deliverables related to the regulatory models are under Task 2 of the Scope of Services.

3 Introduction to stranded costs

Stranded costs, also known as stranded investments or stranded debt, represent costs which a utility was allowed to recover through regulated rates, but the recovery of which may be impeded or prevented as a jurisdiction moves from a regulated regime to a competitive, deregulated environment, or as a result of other unanticipated policy change.

3.1 Sources of stranded costs

Assets become stranded when a utility can no longer recover the costs incurred to acquire and operate these assets through the rate base. Stranded costs can arise for a variety of reasons, for instance, because of a reduction in power demand or the loss of large customers or portions of load following a move from a regulated to a competitive structure (i.e. "retail-turned-wholesale customers"). Another example might be the forced divestiture of some of a utility's assets, whereupon the market value of the divested assets is lower than the book value of the divested assets, or forced retirement of an asset following an unanticipated change in policy. Historically, provided that the investments were prudent and verifiable, utilities have been allowed to recover stranded costs from ratepayers.

Stranded costs can be broadly divided into the following five categories:

- unrecoverable costs of generation-related and/or regulatory assets;
- long-term Power Purchase Agreements ("PPA");
- unrecoverable former government-owned assets;
- unrecoverable investments in social programs; and
- employment transition costs.

Their relative importance can vary, but overall, the first three categories make up the bulk of stranded costs.

3.1.1 Unrecoverable costs of regulated assets

In regulated monopoly markets, utilities generally receive exclusive rights to sell power to retail customers in their service areas at regulated prices. Regulators set electricity rates to recover allowed accounting costs and to give utilities a reasonable rate of return. In jurisdictions mandating a change in ownership of regulated assets, or a change in the regulatory structure, stranded debt arises when facilities are found to be uncompetitive in an open access environment.[10] In such cases, utilities are often reimbursed through some form of a surcharge on customer bills to make up for the decline in the asset's value. These facilities may include power generation facilities, transmission lines, distribution assets, or other ancillary assets. Typically,

[10] The Fifth Amendment of the United States Constitution includes a provision known as the Takings Clause, which states that "private property [shall not] be taken for public use, without just compensation." Utilities have argued that changes in regulation are in effect a form of taking, and that they are thus due compensation.

generation assets account for most of the stranded costs as evidenced by the multiple historical stranded cost proceedings, a few of which are discussed in Section 3.3.

3.1.2 Long-term power and fuel purchase agreements

In order to supply their retail load, utilities can enter into long-term PPAs with independent third-party suppliers, with an expectation that regulators will allow the costs to be passed onto ratepayers. These contracts could become liabilities for the utility if they are not competitive in a new ownership or regulatory environment. Similarly, utilities' long-term contracts to procure fuel could result in stranded costs. These costs that would automatically be passed on to ratepayers under a regulated market likely cannot be passed through in a newly formed competitive regime.

3.1.3 Unrecoverable former government-owned assets

Although not applicable in Hawaii, another situation in which stranded debt arises is when formerly government-owned utilities are broken up and privatized. As the new entities can only be sold with a level of debt that reflects commercial realities, the debt which cannot be placed with the surviving companies then becomes "stranded," net of privatization proceeds, and mechanisms must be developed to assure repayment.

3.1.4 Unrecoverable investments in social programs

Another category of costs that may not be recovered in a competitive market includes costs incurred for social programs, such as demand-side management, emissions reductions, provision of universal service, workforce training, and assistance for low-income customers. The costs of these programs are usually amortized over time.

3.1.5 Employee transition costs

The final category of stranded costs relates to employee expenses prompted by restructuring, such as the costs of offering early retirement or job retraining. Employee transition costs are not stranded costs, but are an expense of moving to a different model. Some regulators have included such expenditures as stranded costs that may be recovered.

3.2 Calculation of stranded costs

The calculation of stranded costs is a process which must include both economic and policy considerations. Several methods have been proposed by generation owners, economists, and regulators. These methods differ by whether they measure stranded costs before or after the restructuring takes place, whether they are based on the estimation or on actual market valuations of assets, and whether they value a company's assets individually or take a more aggregate, "top-down" approach.

At a high level, there are two scenarios that will require the estimation of stranded costs:

- a utility is left with stranded assets following a reduction in power demand (i.e., the departure of a customer from its system); or

- a utility is forced to divest some of its regulated assets, whereupon the market value of those assets is lower than its book value.

3.2.1 Reduction in power demand

In its landmark 1996 order promoting wholesale competition through open-access transmission service, FERC issued guidance for utilities seeking recovery of stranded costs associated with retail-turned-wholesale customers.[11] This scenario arises when a large amount of load seeks an alternative source for power supply than the incumbent utility.

FERC adopted a top-down, revenues lost approach for calculating and recovering legitimate, prudent, and verifiable stranded costs which, among other things, was designed to avoid an asset-by-asset review. If the utility can demonstrate that it had a reasonable expectation of continuing to serve a customer, FERC provides the following formula for calculating the Stranded Cost Obligation ("SCO"):

$$\boldsymbol{SCO = (RSE\ minus\ CMVE)\ times\ L}$$

where:

- **RSE** is the ***Revenue Stream Estimate*** – average annual revenues from the departing customer over the three years prior to the customer's departure, for each service that that departing customer will no longer require from the utility;

- **CMVE** is the ***Competitive Market Value Estimate*** – determined as the opportunity cost of the released capacity and associated energy, based on a market analysis; and

City of Las Cruces, New Mexico

The City of Las Cruces took steps to municipalize its electric system, departing the El Paso Electric Company ("El Paso") system and purchasing power from another supplier using El Paso's transmission system.

FERC in a 1998 order found that El Paso was entitled to the recovery of stranded costs of approximately $30 million should the City of Las Cruces depart its system, as their retail rates were approved by the regulator and thus generation costs included in those rates are legitimate, prudent and verifiable stranded costs. FERC further found that a 10-year planning horizon, beginning when El Paso had a reasonable expectation that Las Cruces would depart its system, appropriately denoted the reasonable expectation period ("L"). FERC argued that this planning horizon is consistent with industry usage, and the lead times for construction and operation of generation supply options such as combustion turbines and combined cycle units.

Under the SCO formula, FERC calculated the RSE for the most recent 3-year period as the average revenue received by El Paso during this period, adjusted for transmission-related revenue (including ancillary services), distribution costs, taxes other than income taxes, and other fees. For the CMVE, FERC elected to use as a proxy for the value of released capacity and energy, the cost of power purchased by El Paso from another supplier that would be displaced by the released energy and capacity.

Source: FERC Docket SC97-2-000

[11] Although utilities in Hawaii are not under FERC jurisdiction, the guidance provided by FERC still represents a relevant reference.

- **L** is the ***Length of Obligation*** (reasonable expectation period) – refers to the period the utility could have reasonably expected to continue to serve the departing generation customer.

3.2.2 Mandatory divestiture of regulated assets

In other scenarios, regulated utilities can be mandated through a change in ownership or regulatory structure to divest part or all of their regulated assets (most typical in the generation sector). In that case, the stranded costs calculation compares the value of the utility's assets in the regulated environment with the value of these same assets in the newly formed environment. In other terms, the stranded costs are computed as the difference between the current market value of the asset and the historical cost of the asset depreciated through time (i.e., book value).

In practice, a certain amount of negotiation also takes place between the utility, regulator, and other stakeholders in order to establish the exact amount of stranded costs allowed to be recovered.

NYSEG and Niagara Mohawk divestiture of nuclear generation

Following the restructuring of the New York electricity industry in the late 1990s, the regulator adopted policies to open the electric system to competition and to allow electric generation companies to compete in the sale of electricity. In one example, Niagara Mohawk and several other utilities were directed to divest their interests in the Nine Mile Point 1 ("NMP-1") and Nine Mile Point 2 ("NMP-2") nuclear generation facilities in upstate New York. The sale of the assets was the result of a competitive bid and auction process.

The sale of the Niagara Mohawk's interests in NMP-1 and NMP-2 created a measurable stranded cost of $1,196 million, which they determined by comparing the net sale proceeds ($519 million) to the net book value of the assets and liabilities ($1,715 million) at the time of the closing. The regulatory book basis included such components as net plant, construction work in progress, nuclear fuel, materials, and supplies inventory, deferred debits and credits, post-employment benefits liability, etc.

Following a negotiated settlement with several key stakeholders, they presented a joint proposal to the regulator establish a regulatory asset to recover $1.2 billion in stranded costs, minus a negotiated write-off for $123 million. The regulator ultimately found the proposed sale of the Nine Mile nuclear generation assets in the public interest and authorized the transfer.

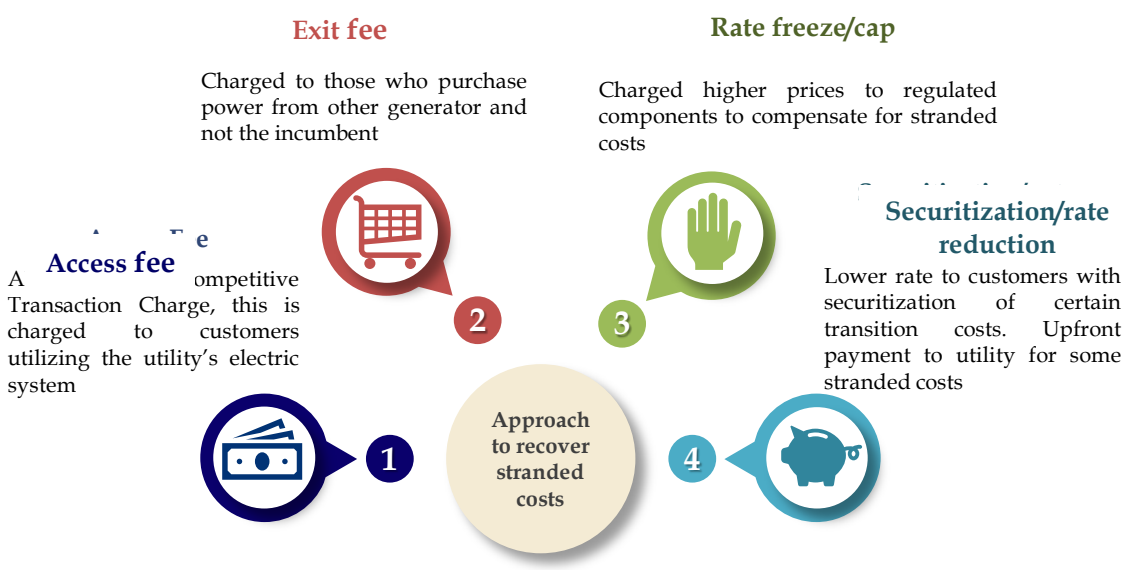
Source: New York Public Service Commission, Case 01-E-0011

3.3 Collection of stranded costs

Several mechanisms have been used or proposed to allow utilities to recover stranded costs. Though mechanisms discussed below have different effects on different types of customers, all the surcharges on the electricity consumers are only transitional in nature and are eliminated at the end of the transition. Implementation of an access fee (or Competitive Transaction Charge ("CTC")), along with securitization, have been the most frequent methods used to recover

stranded costs following the wave of deregulation efforts in the late 1990s. Figure 3 shows the different approaches to recover stranded costs. These will be discussed in detail below.

Figure 3. Approaches to recover stranded costs



3.3.1 Access fee

CTC fees are typically levied on a customer's current electricity consumption and would be fairly easy to collect. Under this method, certain transition costs and a fixed recovery period are identified. The utility is allowed to collect these costs by imposing an access charge on all customers who utilize the utility's electric system, regardless of whether the customer purchases power from the incumbent supplier or an alternative provider.

It is important to note that while the CTC may seem like an "extra" charge for consumers, it was embedded in the rates in the past, and thus does not represent a rate increase, at least in systems in which there was no previous substantial subsidization of rates.

Arizona

In 1999, the Arizona Corporation Commission ("ACC") began opening retail competition in the state. The ACC also approved plans for recovery of utilities' stranded costs among consumers and shareholders as deemed "to be in the public interest."

The restructuring agreement approved by the ACC allowed Arizona Public Service Company ("APS") to recover $350 million of its estimated $533 million in stranded costs via a CTC that decreases annually over a five-year transition period, and allowed Tucson Electric Power ("TEP") to recover $450 million in stranded costs over a ten-year transition period through fixed and floating (varying inversely with the market price of energy) CTCs.

Source: EIA, Status of State Electric Industry Restructuring Activity

Ontario (Canada)

When the former Ontario Hydro was restructured on April 1, 1999, the Ontario Electricity Financial Corporation ("OEFC") was established to manage and retire the former Ontario Hydro's debt and certain other liabilities, which totaled CAD$38.1 billion. The debt was accumulated by building Ontario's electricity generation and transmission infrastructure.

A portion of the total debt could be supported by the value of the assets of Ontario Hydro successor companies and other assets; however, OEFC was left with CAD$19.4 billion in unfunded liabilities (or stranded debt). OEFC receives dedicated revenues to service and to retire the stranded debt from a number of sources, including:

- Payments in lieu of taxes ("PILOT") from Ontario Power Generation ("OPG"), Hydro One and municipal electricity utilities;
- Electricity Sector Dedicated Income from the province in respect of the net incomes of OPG and Hydro One; and a
- Debt Retirement Charge ("DRC") paid by electricity users.

The DRC is used by OEFC exclusively to meet its mandate, which includes servicing and retiring its debt and liabilities. The DRC came into effect on May 1, 2002, when Ontario's electricity market opened to competition. Under the Electricity Act, the DRC will only remain in place as long as there is residual stranded debt, which is the difference between the remaining stranded debt and the estimated value of OEFC's future PILOTs and certain other dedicated revenues.

Effective January 1, 2016, all residential rate class customers were exempt from the DRC. The DRC remains on all other electricity users' bills. The government is expecting to completely remove the DRC by April 2018.

Source: Ontario government website. < https://www.fin.gov.on.ca/en/tax/drc/index.html >.

3.3.2 Exit fee

An alternative to charging all customers is to charge only those who opt to buy power from a generator other than their incumbent utility (if such practice is allowed under the new regime). Existing customers that retain the incumbent utility as their supplier, as well as new customers irrespective of their choice of supplier, are not subject to the exit fee. The use of an exit fee is a substantial burden on the departing customers and can be viewed as anti-competitive.

Nevada

In 2001, the state of Nevada adopted the 704B law which allowed eligible large customers (those using 1MW and above) to choose an alternative supplier for power with permission from the State PUC. The law included a provision that departing customers pay an exit fee to ensure that departing companies protect remaining ratepayers for energy investments made by the utility to ensure an adequate energy supply for all customers.

In recent years, there have been several high-profile customer defections from incumbent supplier Nevada Energy, seeking to negotiate their own favorable rates for power from the open markets or to reduce their environmental impacts by purchasing renewable energy. Customers opting for alternate energy suppliers include technology giants (Switch, Google) and large casino operators (Wynn, MGM, Caesars). These customers have been assessed exit fees ranging from $16 million (Wynn) to $87 million (MGM).

Source: The Nevada Independent

Alabama

In 1996, Senate Bill 306 established a procedure for customers that wish to change from the incumbent utility to a private supplier for power. The law provided utilities the opportunity to collect exit fees from customers leaving their system to recover the amount of reasonable stranded costs associated with the customers' service. That provision, however, was challenged in court by customer advocacy groups as being unconstitutional. The suit was ultimately dismissed, however, as the PSC closed the formal inquiry into restructuring in the State of Alabama. The decision came after the PSC commissioners determined that it had not been demonstrated that all consumers in Alabama would continue to receive adequate, safe, reliable, and efficient energy services at fair and reasonable prices under a restructured retail market.

Source: EIA, Status of State Electric Industry Restructuring Activity

3.3.3 Rate freezes or caps

Other mechanisms that could be used to collect stranded costs are rate freezes or caps. Under those options, utilities would essentially charge higher prices for the components of the electricity market (such as distribution and transmission) that are still regulated. Any surplus revenues would be used to paydown the approved SCO.

Texas

The restructuring legislation in Texas, Senate Bill 7, was enacted in 1999 to restructure the state's electric industry allowing retail competition. The bill mandated a three-year rate freeze, followed by a rate reduction for certain classes of consumers.

Senate Bill 7 allowed for the recovery of 100% of stranded costs as part of the transition to deregulation through securitization. Overall, various utilities in the state were owed around $6 billion in combined stranded costs.

Source: EIA, Status of State Electric Industry Restructuring Activity; Texas Coalition for Affordable Power

3.3.4 Securitization / rate reduction

Some states have adopted a process that links a rate reduction to certain customers with securitization of certain transition costs. This method allows utilities to receive an up-front payment for some of their stranded costs through a process called securitization. State legislation authorizes utilities to receive the right to a stream of income from ratepayers. Utilities can turn over that right to a state infrastructure bank in exchange for a cash payment. The state infrastructure bank then issues bonds that are backed by that stream of income. The issuance of debt securities would provide the utility with a lower cost of capital and save ratepayers money. The customer surcharge required to pay off the bonds is less than the charge that would be necessary to produce the same amount of money for the utility.

Illinois

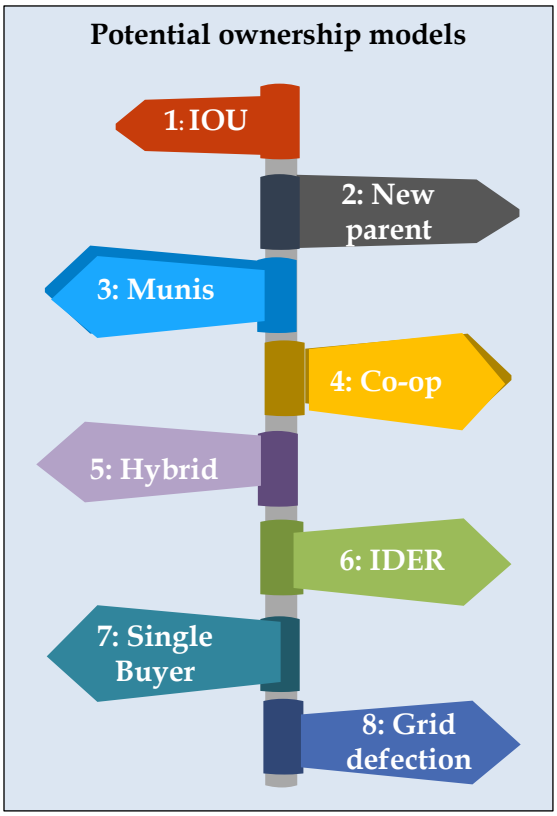
Late in 1997, House Bill 362, "The Electric Service Customer Choice and Rate Relief Act of 1997," was enacted. The bill provided for rate cuts for consumers, and choice for their generation supplier by 2002. The law also allowed partial recovery of stranded costs through transition charges over a ten-year period, as well as securitization of stranded costs under strict guidelines that do not allow for increases in consumer rates.

Source: EIA, Status of State Electric Industry Restructuring Activity

4 Potential stranded costs for various utility ownership models

In a previous working paper discussing potential ownership models for the utilities serving Hawaii's counties (Task 1.1.1./Task 1.2.1),[12] the Project Team introduced eight potential utility ownership models, namely:

- IOU;
- a new parent under IOU ("new parent");
- municipal entity ("muni");
- cooperative ("co-op");
- hybrid, mostly government owned ("hybrid");
- integrated distributed energy resources ("IDER") system operator;
- single buyer ("SB"); and
- grid defection/disperse ownership.



Although there can be wide variations within each ownership types, the Project Team attempted to present each in a way that encompasses the most common forms.

The various ownership models discussed range from the traditional (such as IOU, cooperative, municipal utility, or majority government-owned) to other models that would also require significant changes in the regulatory environment, such as IDER or a single buyer model. This report also discusses the impact of a scenario involving grid defection.

4.1 Traditional utility models

The Project Team considers several ownership models as traditional in the sense that operations are mostly conducted in a traditional manner, where generation, transmission, and distribution functions are conducted or coordinated by a single entity. The models differ only in the perceived motivations of the utility rather than in their function.

[12] Task 1.1.1./Task 1.2.1. Introduction of Ownership Models and Comparison of Ownership Models and How They Relate to the State's Key Factors.

The traditional ownership models include IOUs (status quo), a new parent under IOU, co-op, muni, or a hybrid, majority government-owned model:

- IOU (status quo)
  An IOU can be publicly traded or privately held. In the case of HEI, it is traded on the New York Stock Exchange ("NYSE"). IOU management reports to a board of directors, which has a fiduciary duty to its shareholders. Management, in turn, responds to signals from its regulators regarding priorities.

- New parent under IOU
  IOUs can be owned by other IOUs; they can be owned by private equity firms or conglomerates; the new parent could also be not for profit or a limited dividend or a benefits ("B") corporation. New parents can facilitate growth and innovation, but can also mean significant leverage and potential distress.

- Co-op
  Co-ops are a form of ownership in which a company is effectively owned by its members, who are normally its customers. They are incorporated under the laws of the state in which they operate.

- Muni
  Municipal utilities ("munis") are generally owned by cities and towns. Many municipal utilities arose out of public works departments in various cities and towns; over time, these assumed a separate corporate identity from the cities that own them and that they serve.

- Hybrid, majority government-owned
  Hybrid ownership models typically mostly arose from governments partially privatizing a utility which was formerly 100% government owned. Hybrid entities generally are exempt from civil service restrictions and are somewhat insulated from political interference.

Within those traditional models, it is also possible to mix and match ownership models across the value chain; there are utilities, co-ops, and munis who own only wires, only generation, or combinations thereof. For instance, one possible scenario involves the change in ownership model to include all HEI assets in the generation, transmission, and distribution sector. Another possible scenario, however, would include the transfer to a new entity of the transmission and distribution assets[13] (as well as existing generation contracts), whereupon the IOU would retain its own generation assets and essentially become an IPP contracted to the new entity.

[13] Given the unique nature of the island grids, the distinction between transmission and distribution is not meaningful in Hawaii.

4.1.1 Transfer of generation, transmission, and distribution assets to new owner

In this scenario, the new owner would be tasked with performing the generation, transmission, and distribution functions in each county. As such, it is reasonable to expect that the new entity would acquire all assets from the incumbent utility that are required to perform these functions.

At present, all utility assets in all the counties are included in their respective rate base, and the costs are recovered through electricity rates. While the bulk of utility assets are comprised of generation, transmission, and distribution assets, other categories such as real estate, inventory (for fuel, materials, and supplies), or "accounting" assets (such as investments related to employee pensions or deferred costs) are also included.

Kauai Island Utility Cooperative ("KIUC")

KIUC is the member-owned electric cooperative serving Kauai county. KIUC purchased the assets of the incumbent investor-owned utility (Kauai Electric) in 2002.

KIUC's first attempt at purchasing the assets from Kauai Electric in 2000 was rejected by the Hawaii Public Utility Commission ("HPUC") which deemed that the transaction was not in the public interest because the risks of KIUC ownership outweighed potential benefits, and KIUC was not financially fit to own and operate Kauai Electric. In 2002, the parties resubmitted an updated agreement for KIUC to purchase all assets from Kauai Electric at a lower price of $217.5 million, based on a value of net assets of $180.4 million plus an acquisition premium of $37.1 million. At the time, the physical assets had a book value of $168 million. Given that the proceeds from the sale outweighed the book value of the assets, the incumbent utility did not seek recovery of any stranded costs as a result of the transaction.

The revised agreement also included several commitments, including a one-time rebate for consumers, KIUC's agreement not to seek rate recovery of transaction costs or amortization, and KIUC's preparation and submittal of resource planning, financial reporting, and emergency planning documents.

Source: HPUC Docket No. 02-0060

In all cases, the utility assets, or rate base assets, have been procured under the oversight of the PUC and thus can be presumed to be reasonable and necessary to the continued reliable operation of the power grid in each county. Similarly, all independent power producers' ("IPPs") generation assets are under contract with regulated utilities, and the contract costs are also recovered through electricity rates.

As such, one can reasonably expect that the new owner would procure all assets from the incumbent utility. This transfer would also include employees from the incumbent utility, and the new entity would need to assume ownership of the existing fuel procurement contracts and power procurement contracts. Indeed, as the load patterns would in no way be affected by the change in ownership, it is reasonable to expect that all existing assets are needed to ensure continuity of reliable service. This scenario would not leave the incumbent with stranded assets or costs.

Furthermore, since the new owner would seek rate recovery of costs and investments for those assets under the same regulatory regime as existed for the incumbent, and would be expected to earn a regulated return, there is no reason for the transfer price of those assets to be below the assets' book value. Since the incumbent would receive proceeds from the sale at a minimum equivalent to the book value of its assets, the company would not be left with stranded investments.

4.1.2 Transfer of transmission and distribution assets to new owner, while IOU retains generation assets

Another possible scenario would involve the change in ownership of the wires assets (and related employees, inventory, and "accounting" assets), while the IOU would retain the assets related to the generation resources. Under this structure, the new entity would operate the system and possibly own generation resources in the future, but to start with would need to assume ownership of the existing contracts for power supply, as well as provide contracts to the incumbent utility for the use of the existing fleet of generation assets. The incumbent utility would essentially become an IPP with assets contracted to the new entity (since the change in ownership does not affect the regulatory model, and the cost of generation, whether owned or contracted for, would still be recovered through regulated rates).

Indeed, as discussed in the previous section, the load patterns would in no way be affected by the change in ownership. Furthermore, due to the unique characteristics of the state where each island operates an independent power grid, there are no existing alternative sources of power but those currently serving each county's load. As such, in contrast with historical case studies where retail-turned-wholesale customers were at liberty of procuring a new competitive supply, the incumbent utility's assets would still be required to ensure an adequate supply of power to the various grids, and would therefore not be left with uncontracted and stranded generation assets. Indeed, contracts could take into account remaining useful life, lengthen accounting life, and reduce rates by changing the recovery period.

4.2 IDER system operator

An IDER represents a new approach to utility ownership. Under an IDER model, the "utility" is confined to the wires portion of the business and is required to provide open access to all distributed energy resources ("DERs") connected to it at a price that recovers the utility's costs.

Under this scenario, the incumbent utility would need to divest its generation assets or move them to a competitive subsidiary. The IDER structure cannot be implemented without a change in the regulatory environment of the power sector in Hawaii, which would create the framework to appropriately compensate generation resources (such as an open market, standard offer construct, bilateral transactions, or other hybrid structure). Since any potential stranded costs for the incumbent utility's generation assets are based on the positive difference (if any) between the value of those assets in the current regulated environment (a function of the assets' book value) and the value of those same assets in the new IDER environment, the Project Team will further discuss the potential stranded costs associated with IDER in its subsequent work paper on regulatory models.

In the IDER model, there is also a potential for stranded costs associated with the existing IPP power procurement contracts, in the event those contracts need to be either modified or terminated so the current IPP resources can participate in the new IDER environment.

4.3 Single buyer

There are some variants of the Single Buyer ("SB") approach worldwide. In some cases, the SB is set up as a stand-alone, not-for-profit entity; in others, it is part of an independent system operator or ISO; a third variant has the utility itself take on the role while being forbidden from bidding its own projects into SB procurements.

The SB, whether it is the incumbent utility or an independent entity, would procure generation consistent with an integrated resource plan ("IRP") or other planning mechanisms. The procurement of resources can be made in a competitive environment resulting in "market" prices, such as for instance with an Independent System Operator structure; however, the procurement can also consist of longer-term contracts, whereupon the cost of the generation contracts would be recovered through regulated rates as is the case currently.

Similar to the IDER structure, a change in the regulatory structure could give rise to stranded costs for the incumbent utility should the value of its generation assets be lower in the new environment than under the current regulated regime. The Project Team will discuss these potential stranded costs in its future work paper discussing various regulatory models. For the purposes of this discussion, assuming the advent of the single buyer model in Hawaii counties, the incumbent utilities would need to divest their generation assets or move them to a competitive subsidiary, as for the IDER model. However, as the assets would remain under a regulated regime (i.e., their costs are recovered through electricity rates), and for the same reasons as discussed in Section 4.1.1, the transfer price of those assets would be at least equivalent to the assets' book value. As such, the incumbent would not be left with stranded investments.

4.4 Grid defection/disperse ownership

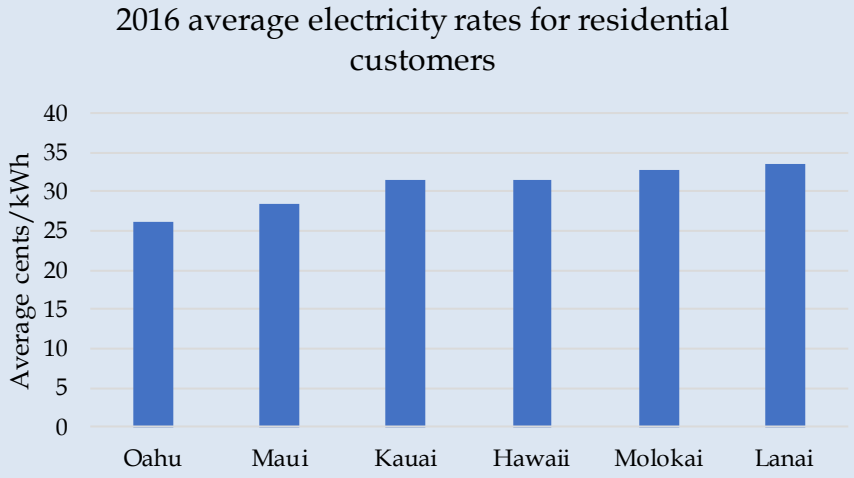
As discussed in Task 1.1.1./Task 1.2.1, the grid defection scenario would become more likely were there to be a combination of rapid cost declines, unwillingness to implement creative ideas on the part of the utility, and regulators' failure to consider, or slow implementation of innovative changes to rate design .

Under a grid defection scenario, portions of the incumbent utility assets (both generation and wires) in each county may become superfluous as customers leave the grid. Technically, these superfluous assets would not result in stranded costs as they would still be included in the rate base driving rates for the remaining customers. However, as more customers elect to cease receiving service from the grid, the utility fixed costs are passed on to remaining customers, leading to increasing rates and more grid defection.

Even if the superfluous assets were to be removed from the rate base ahead of the end of their service life, the utility would still be allowed to claim recovery of stranded costs related to these assets, likely resulting in no net change to cost for ratepayers.

Which islands have the highest electricity costs?

Typically, one would expect the risks of grid defection to be higher for those counties where the regulated electricity rates are higher are more susceptible to see customers opting to self-supply outside of the grid. In 2016, residential consumers on the island of Lanai paid nearly 30% more for their electricity than residential consumers on Oahu.

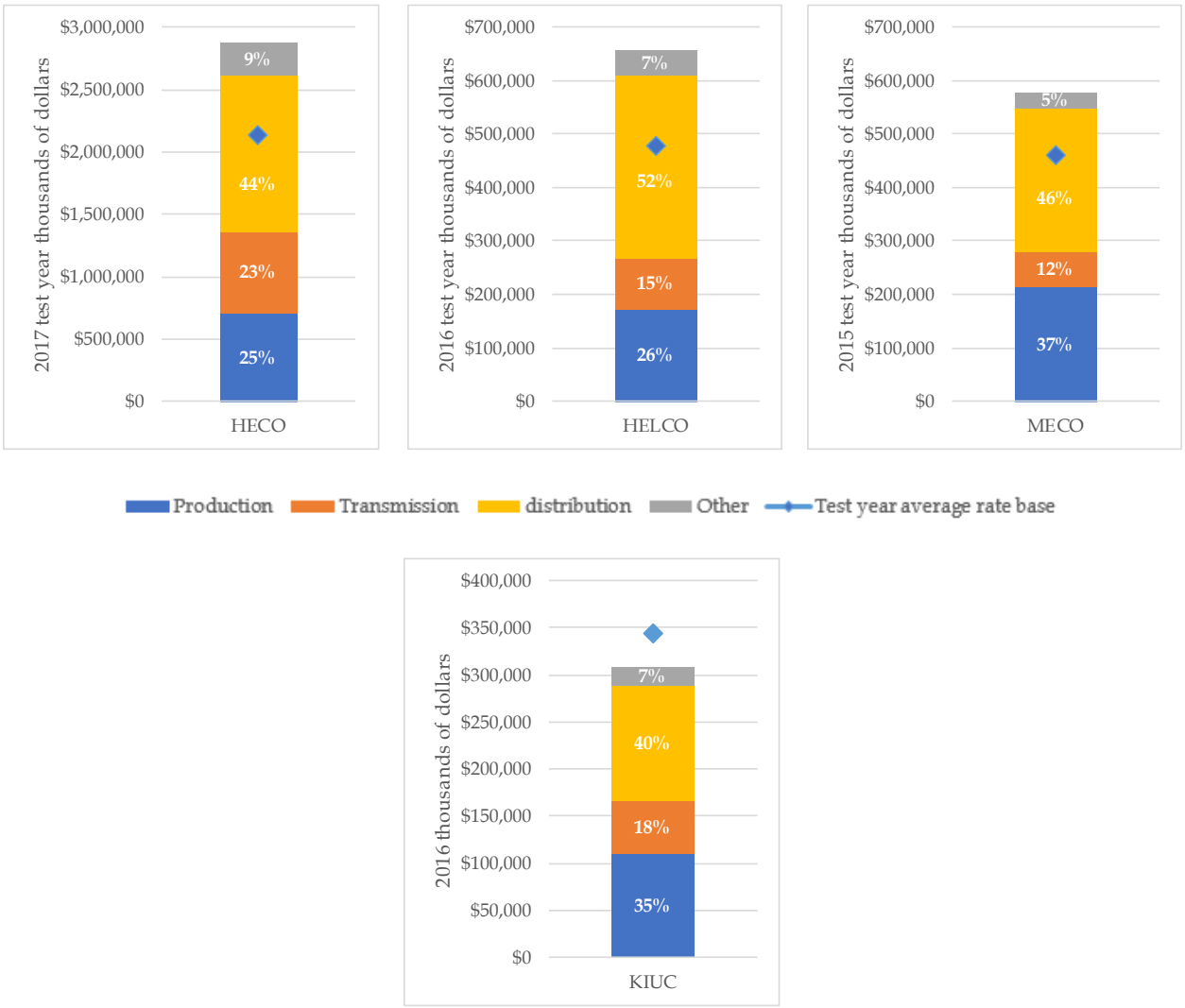


Source: HEI website, KIUC website

5 Assets at risk

As discussed in Section 4, some of the contemplated ownership models (such as IDER, SB, or grid defection) could put some assets at risk of being stranded, especially in the generation sector following a change in the regulatory regime. Typically, wire assets (transmission and distribution) are less at risk of becoming not useful or stranded, absent a dramatic change in load pattern (for instance following the loss of large commercial/industrial customers, or significant grid defection). On the other hand, generators are more at risk of becoming stranded since there are more options to replace resources, especially in an IDER or SB structure.

Figure 4. Value of the Hawaii utilities regulated net plants in service



Note: For KIUC, breakdown of net utility plants by category and rate base are estimated from data from the 2016 annual report

Source: HECO Rate Case Docket 2016-0328; HELCO Rate Case Docket 2015-0170; MECO Rate Case Docket 2014-0318; KIUC annual 2016 report

Figure 4 illustrates the value of net plants in service[14] for Hawaii's four utilities, which include the net value of production, transmission, distribution, and other[15] assets. The value of these assets is included in the utilities' rate base calculation, which then, in turn, is a component in the calculation to determine electricity rates for consumers.

In their 2017 test year rate case,[16] HECO assumed a net cost of plant in service of $2,869 million, where generation assets comprised approximately 25% of the total value. Similarly, HELCO in their 2016 test year rate case[17] assumed a net cost of plant in service of $657 million where generation assets comprised approximately 26% of the value. MECO[18] and KIUC[19] have respectively $587 million and $309 million of net plant in service, with generation resources comprising respectively 37% and 35% of the total value. Currently, a significant proportion of electricity generated on Hawaii's six serviced islands comes from thermal resources, burning a variety of fuels such as coal, residual fuel oil or diesel, as discussed in Task 1.1.3. The proportion of thermal resources will decline over time, though, as renewable generation and DER are added to meet the state's renewable energy targets. As such, some thermal assets might lose their usefulness before being fully depreciated at the end of their service life, essentially becoming stranded.

The thermal generation across the state of Hawaii is quite varied, including steam turbines, combustion turbines, and internal combustion engines. Fuels range from coal to oil to various grades of diesel fuel. The fleet shares the common trait, however, of being on average relatively old, as demonstrated in the following sections. This situation tends to decrease the risk of stranded costs, as the book value of those specific assets tends to be considerably lower than for newer assets. However, utilities have made some capitalized investments in order to maintain these resources, and there are some recent, new and under construction thermal generation plants that could pose a risk for stranded costs, as discussed below. The assets that are at risk are generally those that still carry a significant book value, and in sections below the Project Team highlighted assets that are less than 30 years old.

Overall, an estimated total of slightly more than 400 MW of thermal generation throughout the state of Hawaii is less than 30 years old, a portion of which could potentially be a source of stranded costs with the change in ownership and regulatory structure to IDER system operator or SB.

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[14] As of the target date of the source data, which ranges from 2015 to 2017 as noted in the notes of Figure 4.

[15] Includes vehicles, land, and general assets.

[16] HAWAII PUC Docket 2016-0328. "Application for Approval of General Rate Case and Revised Rate Schedules and Rules." Filed on September 16, 2016.

[17] HAWAII PUC Docket 2015-0170. "Application for Approval of General Rate Case and Revised Rate Schedules and Rules." Filed on June 17, 2015.

[18] HAWAII PUC Docket 2014-0318. "Application for Approval of General Rate Case." Filed on December 30, 2014.

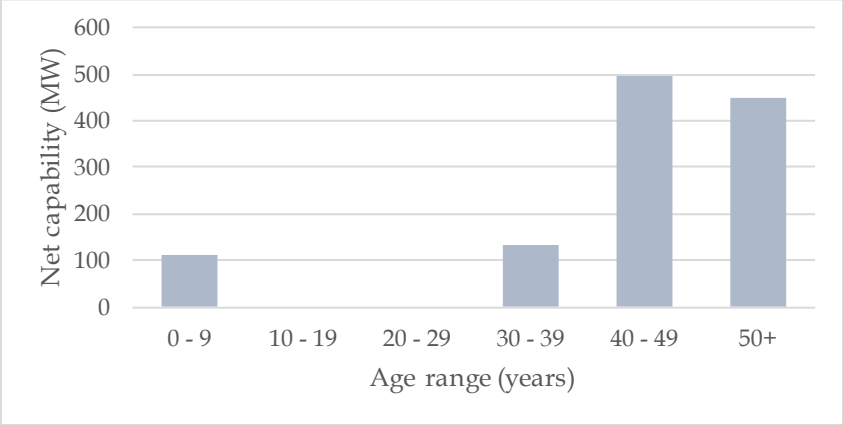
[19] Values estimated from the KIUC 2016 annual report data.

5.1 Honolulu County

HECO's thermal generation fleet on the island of Oahu totals a net capacity of 1,190 MW, in addition to approximately 456 net MW of contracted thermal resources.[20]

As shown in Figure 5, HECO's fleet is overwhelmingly 30+ years old, with an average age of 48 years. The one exception is the 8 years old, 112 MW CIP combustion turbine. Another asset not shown on the above graph is the recently approved 50 MW Schofield generating station, scheduled to come online in 2018. Therefore, up to 162 MW of thermal plants are at risk of being stranded in Honolulu if there is a change of ownership to an IDER, SB, or a grid defection scenario.

Figure 5. HECO thermal generation fleet age



Source: HECO's Power Supply Improvement Plans ("PSIP")

As illustrated in Figure 4, HECO's generation fleet has a net value of approximately $700 million, based on an original cost of generation plants in service of approximately $1,139 million (including Schofield) and accumulated depreciation of $439 million (on average assets are 38% depreciated).[21] Considering that HECO's book value calculations for steam and other production

[20] HECO. "PSIP Update Report." Appendix D. December 2016.

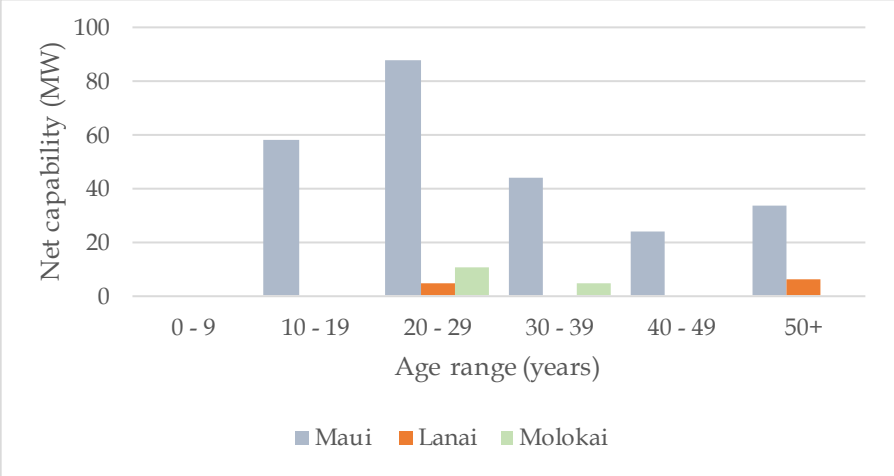
[21] HECO filings present the gross cost of plants in service and accumulated depreciation by asset class (production, transmission, distribution, general, vehicles, and land) rather than being asset-specific.

plant depreciable assets are based on average service life values ranging from 44 to 54 years,[22,23] on average the older assets are almost fully depreciated (except for capital investments made throughout their service life) while the newer assets accounting for most of the $700 million net generation book value have not yet reached the midpoint of their useful life, and are thus a potential source of stranded costs should the renewable mandate lower their effective value under IDER or SB models.

5.2 Maui County

As discussed in Task 1.1.2,[24] Maui Electric's ("MECO") thermal generation fleet is spread throughout the three independent transmission grids on the islands of Maui, Lanai, and Molokai.

Figure 6. MECO thermal generation fleet age



Source: PSIP

The generation capability on both the Lanai and Molokai islands is limited, with both locations relying on diesel-fueled internal combustion engines totaling 10 MW and 15 MW[25] respectively.

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[22] HECO filings calculate average service life values for various National Association of Regulatory Utility Commissioners accounts. For instance, the category "Steam Production Plants" includes accounts for land, structures, boiler equipment, engines, generators, accessory equipment, etc. with each account having a separate average service life.

[23] HAWAII PUC Docket 2010-0053. "Application of Hawaiian Electric Company Inc. for Approval of Changes in its Depreciation Rates, Its CIAC Amortization Period, and Approval of Revised Vintage Amortization Accounting."

[24] Task 1.1.2. Hawaii Maps for Service Areas of Each County.

[25] HECO. "PSIP Update Report." Appendix D. December 2016.

The most recent thermal units on these islands are more than 20 years old, with an average age of 35 years.

Maui island, on the other hand, relies on oil and diesel-fired units totaling 247 MW which are on average 36 years old. Approximately 58 MW of combined cycle combustion turbine capacity at the Maalaea site is less than 20 years old,[26] and 88 MW (combined cycle combustion turbine and diesel internal combustion engines) is between 20 and 30 years old.[27] The remainder of the fleet is more than 30 years old.

As such, approximately 150 MW of thermal generation in Maui could be at risk of being stranded if there is a change of ownership to an IDER system operator, SB, or if grid defection occurs.

As illustrated in Figure 4, MECO's generation fleet has a net value of approximately $213 million, based on an original cost of generation plants in service of approximately $396 million and accumulated depreciation of $183 million (on average assets are 46% depreciated). Considering that MECO's book value calculations for steam and other production plant depreciable assets are based on average service life values ranging from 21 to 52 years for Maui and 28 to 32 years for Molokai and Lanai,[28] the Maui plants less than 20 years old account for most of the net book value, although they are approaching the midpoint of their service life.

5.3 Hawaii County

Hawaii Electric Light ("HELCO") thermal generation assets on the island of Hawaii total 182 MW, in addition to a 60 MW contracted combined cycle combustion turbine.[29]

HELCO's thermal fleet ranges in age from 10 to more than 50 years old, as illustrated in Figure 7. Approximately 61 MW of generation capability is less than 20 years old, including combined cycle capacity at Keahole and a mobile internal combustion engine. There is another approximately 34 MW of diesel generation that is between 20 and 30 years old,[30] while the remainder of the fleet is older than 30 years. These are the capacity that would be most at risk of being stranded with the change of ownership to an IDER system operator, SB, or grid defection.

As illustrated in Figure 4, HELCO's generation fleet has a net value of approximately $173 million, based on an original cost of generation plants in service of approximately $326 million and accumulated depreciation of $153 million (on average assets are 47% depreciated). Considering that HELCO's book value calculations for steam and other production plant

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[26] These include the following plants: Maalaea 17 (21 MW diesel), Maalaea 18 (16 MW diesel), and Maalaea 19 (21 MW diesel).

[27] Ibid.

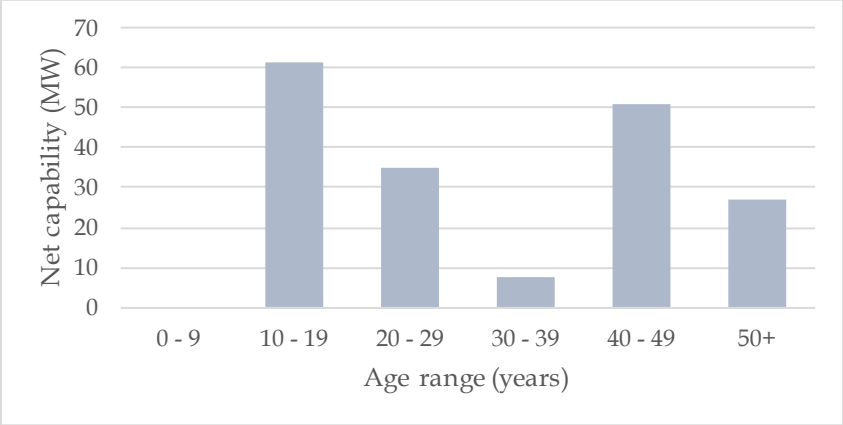
[28] HAWAII PUC Docket 2009-0286. "Application for Approval of Changes in Its Depreciation Rates, Its CIAC Amortization Period, and Approval of Vintage Amortization Accounting."

[29] HECO. "PSIP Update Report." Appendix D. December 2016.

[30] These include the following plants: Kaehole CT2 (13.8 MW diesel) and Puna CT3 (21 MW diesel).

depreciable assets are based on average service life values ranging from 32 to 44 years,[31] on average the older assets are almost fully depreciated (except for capital investments made throughout their service life) while the assets less than 20 years old, having not yet reached the midpoint of their service life, account for a significant portion of the $173 million net generation book value.

Figure 7. HELCO thermal generation fleet age



Source: PSIP

5.4 Kauai County

Kauai Island Utility Cooperative's ("KIUC") thermal generation fleet total slightly less than 125 MW and feature a mix of combustion turbines, steam turbines, and internal combustion engines.[32]

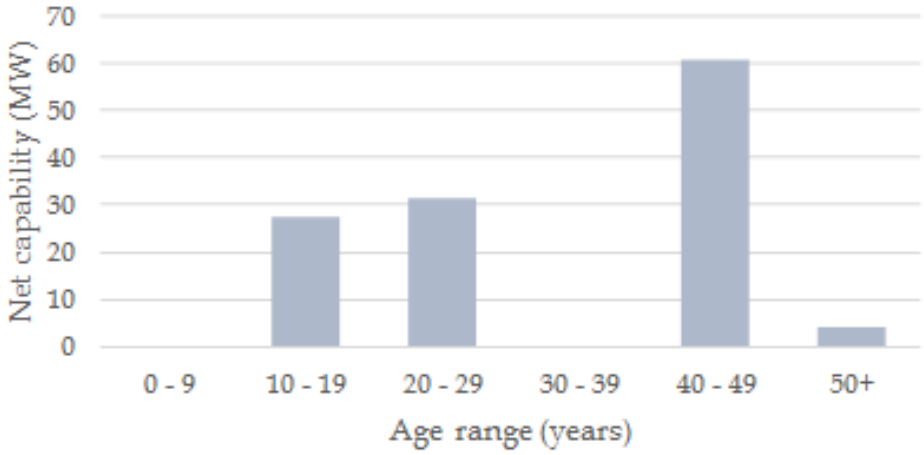
The Kapaia 27.5 MW gas turbine is the most recent thermal asset, having been built in 2002. Other assets at the Port Allen location include four diesel engines that are on average 27 years old; all other assets at that location range from 40 to 53 years old.

As such, the risks of stranded costs for Kauai county are relatively low, given that the need for the newer flexible assets will remain until sufficient renewable generation and dispatching capability exists. By that time, the assets will be nearing the end of their useful life.

[31] HAWAII PUC docket 2009-0321. "Application for Approval of Changes in Its Depreciation Rates, Its CIAC Amortization Period, and Approval of Vintage Amortization Accounting."

[32] KIUC website. Accessed August 15, 2017. < http://website.kiuc.coop/content/energy-information>

Figure 8. KIUC thermal generation fleet age



Source: KIUC website

As illustrated in Figure 4, KIUC's generation fleet has a net value of approximately $110 million, based on an original cost of generation plants in service of approximately $208 million and accumulated depreciation of $98 million (on average assets are 47% depreciated). Assuming that KIUC's book value calculations for steam and other production plant depreciable assets are based on average service life values ranging from 30 to 40 years,[33] we can conclude that on average the older assets are almost fully depreciated (except for capital investments made throughout their service life) while the assets between 10 and 30 years old are approaching or having the midpoint of their service life, account for most of the $110 million net generation book value.

[33] Similar to other non-steam assets for other Hawaii utilities.

6 Appendix A: Scope of work to which this deliverable responds

Task 1.1.6 **Identification of estimated stranded costs for each ownership model by county.** CONTRACTOR shall identify and estimate the impact of any potential stranded assets that may result from a change in ownership model given the findings and conclusions from TASKS 1.1.1 through 1.1.5.

DELIVERABLE FOR TASK 1.1.6. CONTRACTOR shall provide its conclusions and all work to identify estimated stranded costs for each ownership model by county, including analyzing and identifying which utility assets might not be needed under a given ownership model. CONTRACTOR shall provide written narrative in MS Word, spreadsheets in MS Excel, as well as an index of all source information used to generate the deliverable. CONTRACTOR shall submit deliverable for TASK 1.1.6 to the STATE for approval.

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Results of Empirical Research to Support the Assessment of Ownership Models

prepared for DBEDT by London Economics International LLC and Meister Consultants Group

October 28th, 2017

London Economics International LLC ("LEI"), together with Meister Consultants Group ("MCG"), was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals; this document is one of several working papers associated with that engagement. This memo is responsive to Task 1.2.2, which assesses data on comparable utility mergers, acquisitions, and related changes in ownership model, and highlights significant trends or implications for regulation, retail rates, fixed costs, credit ratings, and acquisition costs.

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List of acronyms

DBEDT	Hawaii Department of Business, Economic Development and Tourism
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
HECO	Hawaiian Electric Company
HEI	Hawaiian Electric Industries
IOU	Investor Owned Utility
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International
M&A	Mergers and Acquisitions
MCG	Meister Consultants Group
PSC	Public Services Commission
PUC	Public Utility Commission
PUD	Public Utility District
REV	Reforming the Energy Vision
SWEPCO	Southwestern Electric Power Company
VEMC	Valley Electric Member Cooperative
WMECO	Western Massachusetts Electric Company

1 Executive Summary

This memo evaluates the available data on mergers and acquisitions ("M&A") activity in the electric utility sector to illuminate potential trends or implications of changes in ownership, and ownership structure, on relevant stakeholders. In this analysis, we compiled a dataset of key attributes related to utilities of similar size as those serving each county in Hawaii that were subjected to M&A activity over the last twenty years, and conduct analysis of the retail rate and credit rating impacts of M&A activity, a comparison of acquisition costs to book value, and a discussion of utility regulatory approaches to M&A activity.

The initial data survey generated a sample of 29 transactions that include sufficient data and are comparable in size to Hawaii Electric Companies ("HECO Companies"). Moreover, the data is not typically representative of the kinds of transactions under consideration in Hawaii; most transactions of this size involve the merging or acquisition of the ownership of an investor-owned utility ("IOU") to another IOU ownership entity, rather than a transition towards a municipal utility or a cooperative ("co-op"). The limited sample size of comparable transactions means that we should use caution in drawing conclusions on broader trends or relationships from changes in ownership structure.

Despite the challenge of finding similar and adequately sized sample population for comparison, our analysis revealed a few broader trends in the impacts of merger or acquisitions activity on regulation, rates and rate components, creditworthiness, and acquisition cost.

- **Regulation.** In seven cases, M&A activity led to a change in the ownership model (i.e. IOU, municipal utility, cooperative) of a utility. Generally, in these cases, state regulatory oversight of the utility adjusted to conform to the standard treatment of utilities of the new ownership structure, with some variation based on state and local context. For example, some states adopted transitory periods of freezing rates before reverting to preexisting regulations. In a few select cases with no clear regulatory precedent, or with a deficient regulatory framework, the Hawaii Public Utilities Commission ("PUC") established regulation for the new entity. The remaining 22 of the 29 transactions were between IOUs, which had no impact on regulation.

- **Electricity rates.** While transacted utilities have historically increased their rates in the period following an acquisition, this analysis shows that much of that can be explained by other factors such as changes in supply cost, which impact other (non-transacted) utilities as well. While a direct analysis of rates of 31 transacted utilities showed a rate increase of 1.5 cents/kWh or 16% in the years following an acquisition, these same utilities saw a rate increase of 2.1 cents/kWh or 19%. When controlling for the retail rate changes experienced by other in-state utilities, the post-acquisition retail rate impact that could be attributable to factors such as increased transaction debt decreases to a negligible amount (an average rate decrease of 0.4 cents/kWh or 0.4%). Assessing a subset of utilities that experienced a change in the ownership structure did not notably impact this general increase.

- **Creditworthiness.** As measured by Moody's indicators, utilities often experience changes in creditworthiness following a transaction. However, without further analysis of specific cases, there is not a clear causal link, with no clear trend in terms of upgrading or downgrading of ratings. In the context of HECO Companies, this will be included as part of the detailed analysis of the implications of specific ownership models.

- **Acquisition costs.** Acquisition costs are nearly always a premium over book value. The median of this premium over book value has historically been approximately 1.75, suggesting a market valuation for the electric utilities under Hawaiian Electric Industries ("HEI") that is approximately the same value of the NextEra offer price. However, this figure should be carefully interpreted, since the final acquisition cost is affected by context-specific factors that are unique to each transaction.

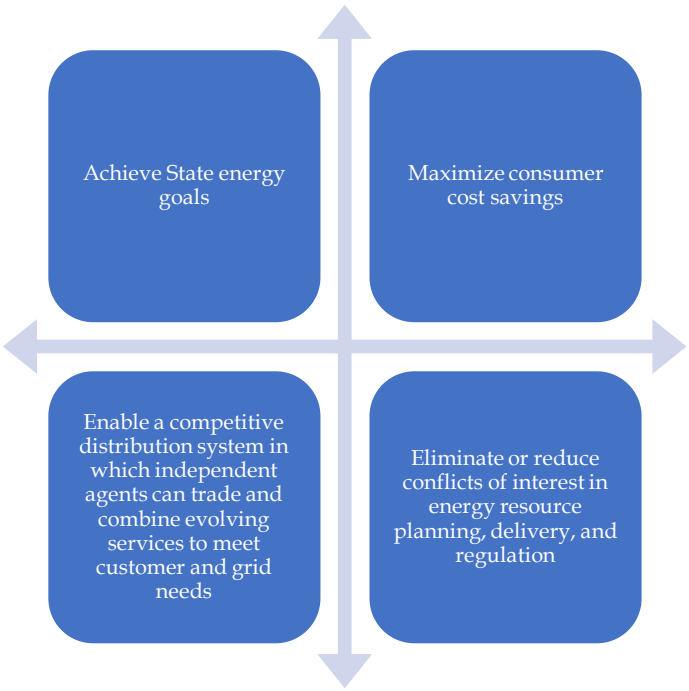
2 Introduction and scope

2.1 Project description

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission on a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. London Economics International LLC ("LEI") and Meister Consultants Group ("MCG", collectively "the Project Team"), through a competitive sealed proposals procurement,[1] was contracted to perform this study.[2]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[3] listed in Figure 1.

Figure 1. State's key criteria



Source: Scope of Services under Contract No. 65595

[1] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[2] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[3] House Bill No. 1700 Relating to the State Budget.

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models and determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversity energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[4]

2.2 Role of this deliverable relative to others in the project

This deliverable is responsive to Task 1.2.2 in the project scope of work. It requires us to conduct research and collect data to support a qualitative assessment of ownership models throughout Task 1.[5]

[4] Hawaii Contract No. 65595. Scope of Services.

[5] A more detailed description of the Task is described in the Appendix.

3 Mergers and acquisitions activity overview

This chapter will provide a brief overview of the data sources and methods for identifying relevant mergers and acquisitions ("M&A") activity. The project team conducted a thorough review of electric power industry data sources encompassing over 2,700 instances of M&A involving electric power or related energy assets. It then developed a database of M&A activity occurring over the last two decades which involved utilities of similar size to those serving one of Hawaii's counties. Through this data collection effort, which is described in detail in Section 4 below, we identified a set of 29 transactions involving 32 relevant utilities that fit these criteria.[6] A complete dataset of the utility and transaction data used for this analysis has been provided to DBEDT and accompanies this report.

As noted below, roughly three quarters (22 of 29) of the transactions collected in this database reflected acquisitions or mergers of investor-owned utilities ("IOUs") that occurred without a change in ownership model, or in which both the acquired entity and the acquirer were IOUs (which are referred to as "IOU-only" transactions in this report). There were five cases in which an IOU transitioned to a cooperative or municipal utility[7] (including the acquisition of Kauai Electric in Hawaii), and two in which a cooperative utility transitioned to become an IOU.[8]

As M&A transactions that involved a change in ownership type are of particular interest to this Study, Figure 3 below provides more detail on the seven relevant transactions. **Figure 4** provides the comprehensive list of utility transactions included in this sample.

Figure 2. Summary of Utility M&A Transactions by Change in Ownership Model

Ownership Model Change	Count
IOU-Only Activity	22
IOU transitioning to Cooperative Utility	3
IOU transitioning to Municipal Utility	2
Cooperative Utility transitioning to IOU	2
Total	**29**

Source: Project Team analysis. n = 29 transactions.

[6] In two cases, a transaction involved more than one qualified utility. In this report, some elements of the analysis refer to attributes of the transaction and use a sample size of 29, and some elements refer to attributes of the acquired utilities and use a sample size of 32.

[7] For the purposes of this analysis, this analysis treats Public Utility Districts as municipal utilities.

[8] While reviewing merger and acquisition data, we did note a greater number of acquisitions of cooperative utilities by IOUs, though most these acquisitions were of very small cooperatives which did not meet the size threshold of this analysis.

Figure 3. Detail of Utility M&A Transactions Entailing a Change in Ownership Model

Ownership Change Type	State	Year	Acquired Utility	Acquiring Entity	Description
IOU to Cooperative	MN	2015	Alliant Energy (MN service area)	Southern Minnesota Energy Cooperative	A coalition of twelve existing cooperative utilities purchased the Minnesota service territory of Alliant Energy (dba Interstate Power & Light).
IOU to Cooperative	HI	2002	Kauai Electric	Kauai Island Utility Cooperative (KIUC)	A new cooperative utility, KIUC, was formed and acquired all of the assets of Kauai Electric, which was then a division of Citizens Communications Company.
IOU to Cooperative	MT	1998	PacifiCorp (MT service area)	Flathead Electric Cooperative	An existing cooperative utility purchased the Montana service territory of PacifiCorp (dba Pacific Power).
IOU to Municipality	WA	2013	Puget Sound Energy (Jefferson County service area)	Public Utility District #1 of Jefferson County	A new county-level public utility district formed and acquired the Jefferson County service territory of Puget Sound Energy.
IOU to Municipality	TX	2010	Xcel (Lubbock service area)	Lubbock Power & Light	In a city with two overlapping and competitive distribution networks, Lubbock's existing municipal utility acquired Xcel's (dba Southwest Public Service Co) assets within city limits to form a single and non-competitive utility.
Cooperative to IOU	LA	2010	Valley Electric Member Cooperative	Southwestern Electric Power Company (SWEPCO)	An existing IOU, SWEPCO acquired the assets of Valley Electric, with cooperative members voting to support the acquisition.
Cooperative to IOU	TX	2002	Cap Rock Electric Cooperative	Cap Rock Energy	Cap Rock Electric Cooperative transitioned from a cooperative model to an IOU model (a new for-profit entity was formed for this purpose, initially as a subsidiary of the cooperative). Owner-members voted to

Figure 4. Total Sample of Utility Transactions and Changes in Ownership Model

Acquired/Merged Utility	State	Year	Outgoing	Incoming	Change in Ownership Model
Cleco Power	LA	2016	Investor Owned	Investor Owned	No
United Illuminating Company	CT	2015	Investor Owned	Investor Owned	No
Rochester Gas & Electric Corp	NY	2015			
Interstate Power & Light (Minnesota service territory)	MN	2015	Investor Owned	Cooperative	Yes
Upper Peninsula Power Co	MI	2014	Investor Owned	Investor Owned	No
UNS Electric	AZ	2014	Investor Owned	Investor Owned	No
Maine Public Service Company	ME	2014	Investor Owned	Investor Owned	No
Sierra Pacific Power	NV	2013	Investor Owned	Investor Owned	No
Central Hudson Gas & Electric	NY	2013	Investor Owned	Investor Owned	No
Puget Sound Energy (Jefferson County service territory)	WA	2013	Investor Owned	Municipal	Yes
Green Mountain Power	VT	2012	Investor Owned	Investor Owned	No
Granite State	NH	2012	Investor Owned	Investor Owned	No
Western Massachusetts Electric Co (WMECO)	MA	2012	Investor Owned	Investor Owned	No
Sierra Pacific Power (California service territory)	CA	2011	Investor Owned	Investor Owned	No
Southwest Public Service Co (Lubbock service territory)	TX	2010	Investor Owned	Municipal	Yes
Valley Electric Member Corp	LA	2010	Cooperative	Investor Owned	Yes
Acquila, Inc	CO	2008	Investor Owned	Investor Owned	No
Texas - New Mexico Power	NM	2007	Investor Owned	Investor Owned	No
Union Light, Heat & Power Co	KY	2006	Investor Owned	Investor Owned	No
Cheyenne Light Fuel & Power Co	WY	2005	Investor Owned	Investor Owned	No
Central Illinois Light Co	IL	2003	Investor Owned	Investor Owned	No
Cap Rock Energy Cooperative	TX	2002	Cooperative	Investor Owned	Yes

Kauai Electric	HI	2002	Investor Owned	Cooperative	Yes
Bangor Hydro-Electric Co	ME	2001	Investor Owned	Investor Owned	No
Louisville Gas & Electric Co	KY	2000	Investor Owned	Investor Owned	No
St Joseph Light & Power Co	MO	2000	Investor Owned	Investor Owned	No
Commonwealth Electric Co	MA	1999	Investor Owned	Investor Owned	No
Central Illinois Light Co	IL	1999	Investor Owned	Investor Owned	No
Pacific Power (Montana service territory)	MT	1998	Investor Owned	Cooperative	Yes
Interstate Power Co	IA	1998	Investor Owned	Investor Owned	No
IES Utilities Inc	IA	1998			
Wisconsin Power & Light Co	WI	1998			

3.1 Discussion of Regulatory Responses to Changes in Ownership Models

The following section describes the regulatory responses to changes in ownership models. In several cases, the change in utility ownership triggered a change in the character of regulatory oversight by state Public Utilities Commissions ("PUCs"). While specific practices of utility regulation vary from state to state, broadly speaking PUCs regulate the rates and activities of IOUs much more closely than municipal ("muni") and cooperative ("co-op") utilities. Typically, PUCs do not regulate muni rates, and only sometimes regulate co-op rates, as in the case of KIUC. Generally, these regulatory responses involve: 1) the application of existing laws for IOU, muni, or co-op regulation onto the new entity, and 2) changes in regulation itself to adapt to unique circumstances (i.e. to respond to situations with no clear precedent, or to repair deficient regulations).

The twenty-two IOU-only transactions assessed in the database discussed above did not trigger any structural change in regulatory oversight. In all cases, these utilities were subject to PUC regulation before the transaction, and continued to be regulated post-transaction. Moreover, these IOU-only transactions occurred across a wide range of regulatory structures, with twelve of the twenty-two transactions occurring within traditionally-regulated state power markets, and ten occurring in restructured markets with unbundled supply and delivery activities and competitive retail sales.[9]

In three of the five cases in which an IOU transitioned to another ownership model (the cases of Alliant Energy in Minnesota, PacifiCorp in Montana, and Xcel in Lubbock, Texas), an existing cooperative or municipal utility acquired the IOU and PUC oversight over the acquired service territory was lessened or removed. In Texas, as municipal utilities are not subject to state PUC regulation, former Xcel customers in Lubbock were no longer regulated by the state after the transition to municipal control. In both Minnesota and Montana, state regulators do not have oversight over cooperatives, but in both cases the state PUC exercised some control over rates in the initial transition of the IOU to cooperative ownership. In Minnesota, the state PUC approved a plan to transition previous Alliant customers to cooperative service territories that was contingent on keeping the rate base portions of electricity bills constant for three years following the acquisition,[10] though the PUC does not have long term regulatory authority over cooperative utility ratemaking in the state. In Montana, Flathead Electric Cooperative's purchase of PacifiCorp's territory was also initially subject to oversight from the state Public Service Commission, which approved the sale on the condition that Flathead continue to charge

[9] For reference, "traditionally-regulated" state power markets refer to vertically integrated electric utility companies that typically manage all aspects of the electricity value chain, including transmission, distribution, and generation. Regulators maintain oversight of these natural monopolies. "Restructured" or "deregulated" markets allow for a greater degree of competition in the generation sector.

[10] Waseca County News, "Southern Minn. energy cooperative files for regulatory approval of sale of electric distribution business", April 16, 2014, available at: http://www.southernminn.com/waseca_county_news/business/article_1bd3ce52-44ab-58de-807a-710badeb08a5.html

PacifiCorp's rates in the acquired territory, though the cooperative would later be permitted to align its rates.[11] Additionally, because certain local jurisdictions within the acquired area were too heavily populated to be served by a co-op under Montana state law, Flathead Electric Cooperative initially formed a subsidiary IOU (Energy Northwest, Inc.) to serve these areas, though it was controlled by the co-op and operated on a non-profit basis.[12]

In Washington State and Hawaii, new entities were formed to acquire the assets of IOUs. In Washington State, where numerous Public Utility Districts ("PUDs") have long operated without oversight from the state Utilities and Transportation Commission, the newly formed Jefferson County PUD began operation without state regulation or oversight. Conversely, in Kauai, the newly formed Kauai Island Utility Cooperative ("KIUC") has been largely subject to the same regulatory process as the investor-owned Hawaiian Electric Companies.[13]

There are also two cases in the dataset where cooperative utilities transitioned to become IOUs. In Louisiana, where co-ops such as the former Valley Electric Member Cooperative ("VEMC") are regulated by the State Public Service Commission, and as a result, there was no substantive change in regulatory oversight after the acquisition of VEMC by SWEPCO, with the service territory continuing its regulated status under the ownership of the IOU. In Texas, where the state PUC does not regulate co-ops, the transition of Cap Rock from a co-op to an IOU initially did not lead to any regulatory change due to a loophole in the state law that continued to classify the newly formed IOU as a co-op for regulatory purposes.[14] However, a change to Texas state law the following year recategorized the utility for regulatory purposes and provided the Texas PUC with regulatory oversight of Cap Rock,[15] though it would be another decade before Cap Rock (by then reorganized as Sharyland Utilities) would be subject to the retail choice regulations in place for other Texas IOUs.[16]

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[11] Montana Public Service Commission, "PSC Approves Sale of PacifiCorp's Electric Distribution Facilities to Flathead Electric Cooperative", November 2, 1998, available at: http://www.psc.mt.gov/news/pr/19981102_PSC_Approves_Sale_of_PacifiCorps_Electric_Distribution_Facilities_To_Flathead_Electric.pdf

[12] Federal Communications Commission, "TCI Cablevision of Montana, Inc. v. Energy Northwest Inc.", Order DA 001901, August 18, 2000, available at: https://apps.fcc.gov/edocs_public/attachmatch/DA-00-1901A1.pdf

[13] It should be noted that there is a greater precedent across state PUCs for regulating the rates and activities of co-op such as KIUC than of public entities such as Jefferson County PUD. Generally, PUCs do not regulate munis or PUDs beyond safety issues. While many state PUCs (such as those in California and Oregon) do not regulate co-ops, others (such as those in Arizona and Arkansas in addition to Hawaii) do regulate the rates and other activities of cooperative utilities.

[14] Securities and Exchange Commission, "Cap Rock Energy Corporation Form 10-K Annual Report", December 31, 2001, available at: https://www.sec.gov/Archives/edgar/data/1129162/000091205702013399/a2075466z10-k405.txt

[15] Electric Light & Power, "Senate Bill 1280 signed by Texas governor", June 26, 2003, available at: http://www.elp.com/articles/2003/06/senate-bill-1280-signed-by-texas-governor.html

[16] Sharyland Utilities, "Your future in the Competitive Retail Electricity Market", 2014, available at: http://www.sharyland.com/wp-content/uploads/2014/06/SUCompetitionEducationBrochure.pdf

In summary, in nearly all cases, state PUCs reacted to a change in utility ownership model by applying the preexisting regulatory practices in place for the incoming ownership model in that state to that utility, though occasionally with a transition period in place. The only partial exceptions to this rule were the cases of Cap Rock Energy and Kauai. In the former, an adjustment to state law was needed to clarify that the new entity was to be regulated as an IOU rather than a co-op due to a loophole in prior law. In the case of Kauai, as there were no prior electric co-ops in Hawaii, there was no regulatory precedent to apply to KIUC. Instead, KIUC, the Consumer Advocate, Citizens Communications Company, and the Department of the Navy, agreed to not seek or support any reduction or elimination of PUC oversight of KIUC until January 1, 2008.[17]

3.2 Utility retail rates after acquisition

This section and evaluates the relationship between M&A transactions and retail rates. Frequently, a utility undergoing an acquisition will take on significant debt, which would be repaid through rate increases over time. A key consideration when looking trends in utility rates after an acquisition is whether rate changes are due primarily to changes in the utility's fixed costs (i.e. an increase in debt, among other factors) or due to independent changes in the utility's variable costs (such as changes in power supply prices). Box 1 below demonstrates how the latter may come into play, using the case of Kauai Island Electric Cooperative.

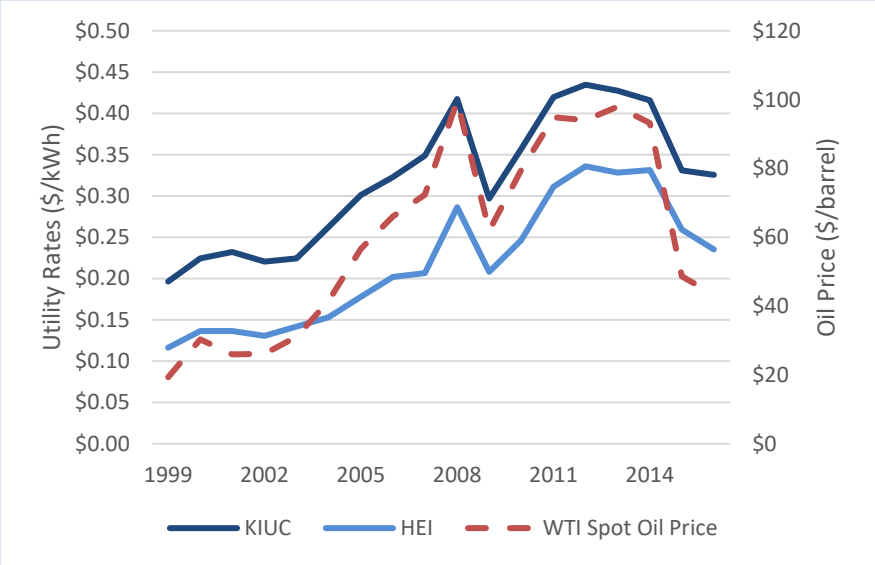
[17] "Stipulation in Lieu of Preliminary Position Statements, Exhibits A&B" Docket No. 02-0060, *For approval of the sale of certain assets of Citizens Communications Company, Kauai Electric Division and related matters*, p. 30.

Box 1. The Impact of Fuel Supply Price Fluctuation on Rates Following the Formation of KIUC

In the six-year period following KIUC's acquisition of Kauai Electric, the utility's electricity prices increased by 89% (from $0.221/kWh in 2002 to $0.417/kWh in 2008),[18] before stabilizing and declining by 22% from the 2008 peak by 2016 ($0.326/kWh). However, KIUC's rates are driven in large part by the global price of oil (because petroleum accounts for a majority of the generation portfolio across all of Hawaii's utilities), which increased nearly four-fold in the six years following the acquisition (from $26/barrel in 2002 to $100/barrel in 2008),[19] before declining again by 57% (down to $43/barrel) by 2016.

Over the same period, the combined average rate of the HECO utilities (which have tracked slightly lower than Kauai's over time on an aggregate basis) experienced a fluctuation in prices that mirrored KIUC's. This is shown in Figure 5 below, which charts the change in retail rates among Hawaii's electric utilities as compared to the global spot price of oil. As is made clear in the chart, the overwhelming factor behind the change in KIUC's rates over time has been changes in the price of oil, which accounts for a majority of Hawaii's electricity generation.

Figure 5. Change in Rates of Hawaii Utilities Over Time, Compared to Change in Global Oil Price



Source: Energy Information Administration, Form 861, 1999-2016

[18] Retail electricity prices are sourced from the US Energy Information Administration's Form 861 Annual Utility Reporting datafile and include fixed-price bill components (that is, prices are calculating by dividing total utility revenues in a year by total utility sales).

As shown in this local example, the impact of a utility acquisition on rates cannot be determined simply by evaluating the change in rates following an acquisition, because overall utility rates are determined by a wide range of factors (the price of energy supply and generation chief among them) that are not directly related to an acquisition.

3.2.1 Unadjusted Change in Rates Prior to and Post-Transaction

Looked at on an unadjusted basis, there is an apparent increase in utility rates following a utility acquisition, though it appears to be a continuation of a general trend of increased utility prices. Analyzing retail energy prices for affected utilities in a period from ten years prior to a transaction to ten years following an acquisition,[20] utility rates increase by an average of 1.5 cents/kWh or 16% in the ten years (or longest period in which data is available) following an acquisition. However, this increase is mirrored by a rate increase of similar proportion in the years leading up to an acquisition. In the ten-year period (or longest period with available data) leading up to an acquisition, utility rates have increased by an average of 2.1 cents/kWh or 19%.

Figure 6 below uses a set of box plots to illustrate the change in utility rates over time in the period before and after an M&A transaction.[21] To control for differences in prevailing electricity prices across years and regions, we established a baseline average retail rate for each utility transaction by dividing total utility revenues in the year of a transaction by total utility kWh sales in that year. We then calculated the difference between that transaction-year retail rate and the retail rates seen in each year included in the analysis. The box plots display the distribution of raw changes in utility retail rates over these years, compared to the transaction-year baseline.[22] In this chart, any positive numbers indicate a year in which utility rates were higher than the year of transaction, while negative numbers indicate a year with lower rates.

In the period following an acquisition, 80% of evaluated utilities experienced an increase in electricity prices. Similarly, in the period leading up to a transaction, 74% of utilities increased

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[19] Here, global oil prices are represented by the West Texas Intermediate, and are sourced from the US Energy Information Administration.

[20] For most utilities, data was not available for the full two-decade period. Pre-acquisition data was limited in some cases because US Energy Information Administration data is only available in a consistent format as far back as 1990. Post-acquisition was limited because a number of acquisitions have occurred in the last decade, and have not yet experienced a full decade of post-transaction retail sales. In some cases, data for specific utilities was not available in all years.

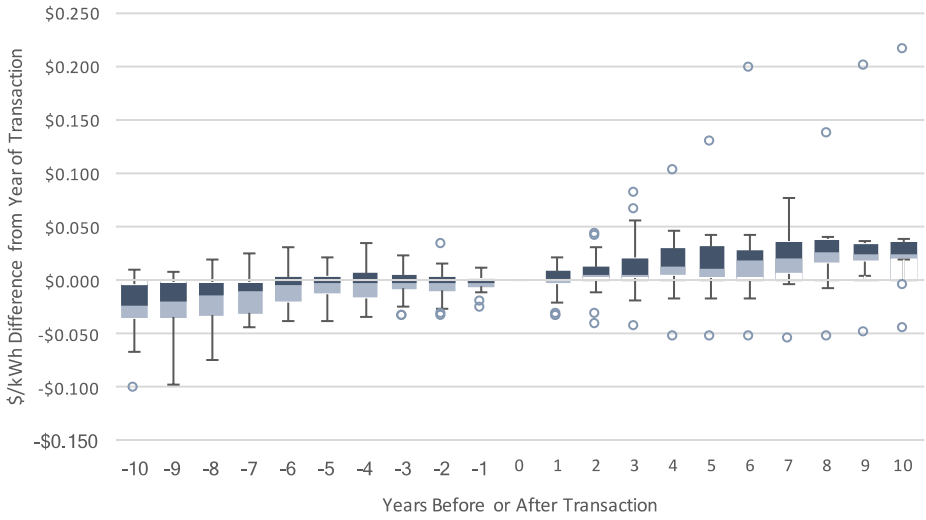
[21] A box plot, or "box and whisker" plot, is a standard means of charting the distribution of a dataset. For each year, the shaded box shows the range of the middle 50% of the data (extending from the 25th percentile to the 75th percentile). Within the box, the divide between shades of blue marks the median point of the data. Upper and lower lines extending from the shaded box mark the minimum and maximum of the data, except for distant outliers which are identified with a circular dot.

[22] Note that in all cases, the change in rates refers to the difference between rates in that year and in the year of M&A transaction. For example, the box plot corresponding to the third-year post-transaction displays the difference in rates in place the year of a transaction and the rates in place three years after the transaction; it does not display the incremental difference in rates between the second and third years following a transaction.

rates. The roughly equal increases in electricity prices before and after M&A transaction serves as an initial indicator that M&A activity may not be a primary driver of rate levels.

The two notable outliers in the post-acquisition period are KIUC, a positive outlier which experienced a significant increase in rates following an acquisition (which as noted above was associated with a sharp increase in oil supply prices) and Bangor Hydro-Electric, which experienced a significant decrease in rates following its acquisition by Emera in 2001.

Figure 6. Raw Changes in Rates Before and After M&A Activity, Relative to Rates In Effect in the Year of Transaction



Source: Energy Information Administration, Form 861, 1990-Current. n=31 utilities; 1 missing data point.

3.2.2 Change in Rates Adjusted for Statewide Activity

However, not all of the change in rates noted above may be attributed only to a change in ownership, as utility rates are constantly under revision due to various factors, many of which are out of an individual utility's control and some of which are associated with time or geographic region.

One way to control for this variation is to situate changes in rates among transacted utilities in the context of rate changes among other utilities in the same state in the same time period using a "difference-in-differences" analysis which compares the rate of change of the impacted utility to its peer group.[23] As these utilities are (in broad terms) subject to similar changes in energy

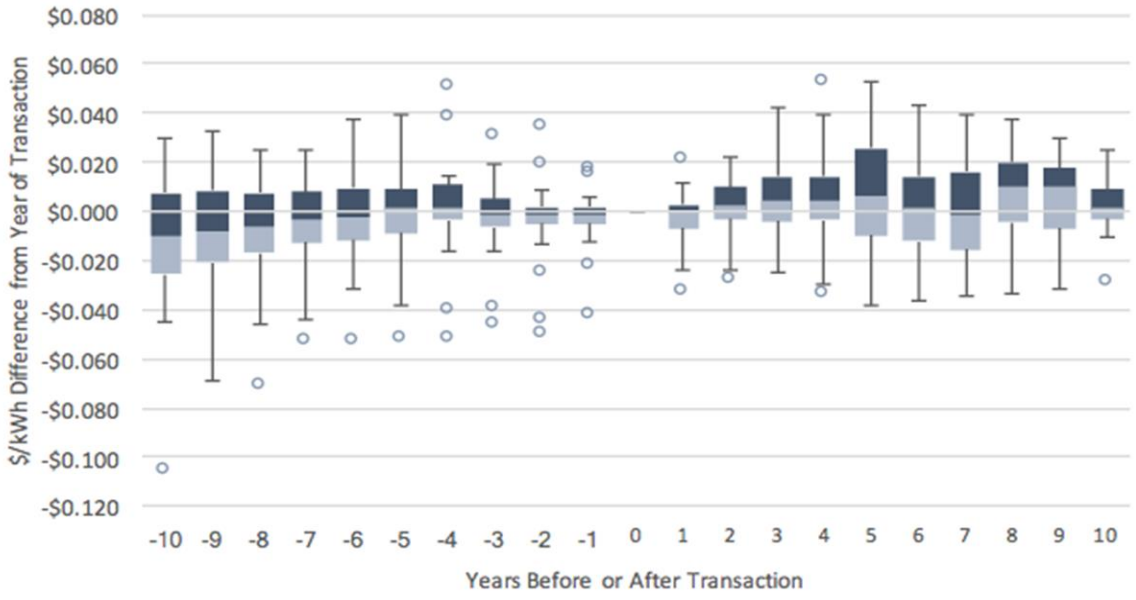
[23] In doing this analysis, wherever possible we looked only at rates from bundled delivery and supply sales to ensure an even comparison of rates across years (as a weighted average of bundled and delivery-only sales would skew the calculation of retail rates over time if the percentage of bundled sales were to change over time). In one case where the utility did not have any bundled customers, we used delivery-only sales. In several cases of utility transactions prior

market prices and state regulation, this analysis can isolate factors that may be specific to a given utility's rates. However, this analysis does not specifically isolate the impact of a transaction on retail rate from other factors that may apply to an acquired utility but not its peer group.

Figure 7 below shows the change in rates that acquired utilities have implemented *net of* whatever rate changes have been enforced by other utilities in the same state in the same time period. In this chart, positive numbers in the period following an acquisition would indicate that transacted utilities have increased rates by a greater amount than their peer in-state utilities, while negative numbers would indicate the opposite.

The distribution of net utility price impacts, both before and after an acquisition, is nearly evenly split among positive and negative values. Slightly over half (58%) of utilities experienced an increase in rates in the period following an acquisition that was greater than their in-state peer group, but the average net change in rates post-acquisition was negative (a net rate decrease of 0.4 cents/kWh, or of 0.4%).

Figure 7. Raw Changes in Rates Following M&A Activity, Relative to Effective Rates One Year Prior to Transaction, Net of Rate Changes of Other Utilities in Same State



When controlling for price factors that also impacted other utilities in the state (which did not undergo M&A activity) the post-acquisition increase in rates that was noted above all but disappears. This provides evidence that the impact of utility acquisitions on rates

to 2001, when the EIA-861 database began to distinguish between delivery and supply customers, we calculated rates from all sales types.

3.2.3 Impacts on fixed and variable cost components of retail rates

An alternate means of isolating the impact of a M&A transaction on rates from the impact of other factors (primarily supply costs) is to isolate the fixed and variable cost components of retail rates.[24]

In addition to the preceding analysis, we also evaluated the relationship between fixed and variable components of retail rates in the period following a utility acquisition, seeking to identify if there were any notable trends in the data on fixed and variable costs passed onto consumers. This could be accomplished by a comparison of the per-kWh amount of revenue collected by utilities through rate components associated with fixed costs (that is, delivery and associated charges) and those associated with variable costs (that is, supply charges).[25] Because debt and other financial factors related to an acquisition would be considered a fixed cost, this approach would isolate the impact of an acquisition from the impact of increasing or fluctuating supply costs.

As there is not a readily accessible and consistent data source that records retail rate cost components across utilities and years, this analysis could not be performed for the dataset as a whole. However, for the subset of acquired utilities that operate in deregulated markets and offer separate rates for full-service and delivery-only customers, those utilities' delivery-only rates may be used as a proxy for the rate components intended to recovery utility fixed costs, and the difference between those utilities' bundled and delivery-only rates may be used as proxy for their variable supply costs. While both resulting rates will include some degree of both fixed and variable costs, these are the most readily available proxies for assessing utility fixed and variable costs over time.

There were six utilities in the dataset with adequate histories of offering both bundled and unbundled rates that could be used in this analysis. They were all transactions from the ownership of an IOU to another IOU, involving no change in ownership model. For each of these utilities, the change in delivery and supply charges over time were calculated. As with the above analysis, a difference-in-differences analysis was used to adjust these rate changes to net out changes in delivery and supply charges implemented by other utilities in the same state in the same time period (in order to net out the impact of any factors that impact rates that would also impact the rates of peer, non-transacted utilities). The result is the table below, which compares the per-kWh change in delivery and supply charges levied by transacted utilities following a utility transaction, net of similar rate changes enforced by other in-state utilities. This analysis

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[24] While utility rates include both variable cost components (that is, bill components charged on a $/kWh of $/kW basis) and fixed cost components (bill components charged on a $/month or similar basis), it is a frequent practice in utility rate-setting to use variable rates to recovery a majority of a utility's costs, including both fixed and variable costs.

[25] An alternate means of evaluating the difference between fixed and variable costs would be to evaluate fixed and variable retail rate components, meaning a comparison of the change in flat per-month charges to the change in volumetric per-kWh charges. However, it is relatively rare for utility rates to be designed in a manner that recovers fixed utility costs through a fixed charge and variable costs through a variable charge. Instead, much of a utility's fixed costs are frequently recovered on a per-kWh basis, particularly in the residential sector. Therefore, we suggest the approach used in this section, which operationalizes delivery-only charges as a proxy for all fixed network costs, and uses the supply charge-premium of utilities in deregulated markets as a stand-in for variable utility costs.

compares the rates offered by impacted utilities (and their peer utilities) in the year before a transaction to the latest year in which data is available, which is between one and four years following a transaction depending on the utility.

Figure 8. Summary of Change in per-kWh Delivery and Supply Retail Rates Components in Period Following Acquisition, Net of Rate Changes of Other Utilities in Same State

Utility	State	Change in Delivery Charges	Change in Supply Charges	Total Change in Rates
Central Hudson Gas & Electric	NY	$0.011	-$0.001	$0.010
Granite State	NH	$0.015	-$0.012	$0.003
Rochester Gas & Electric Corp	NY	$0.009	$0.001	$0.011
Sierra Pacific Power	NV	$0.004	-$0.014	-$0.010
United Illuminating Company	CT	-$0.014	$0.014	$0.000
WMECO	MA	-$0.015	$0.022	$0.007
Average		**$0.002**	**$0.002**	**$0.003**

Source: Energy Information Administration, Form 861, 1990-Current. n=6 utilities; only utilities with both bundled and delivery rates included.

Among these six utilities, overall rates relative to peer in-state utilities increased in all but one case over this period, by an average of 0.3 cents/kWh, which is equivalent to a 2% increase in rate. Among delivery and supply charge components, four of the six utilities increased their delivery charges, while three increased their supply charges. The overall increase in utility rates was split evenly among delivery and supply charge, and while individual utilities may have seen a greater relative increase in one cost area than another, there was no clear trend among the utilities as a group.

As with the above section comparing changing utility rates over time to those of peer utilities, this analysis provides limited evidence for a relationship between utility acquisition and increased electricity rates, which could be supported by an increase in the delivery charges of impacted utilities relative to other utilities in the period following acquisition. However, this analysis is limited by both a small sample size as well as a short time period.

The latter point is relevant because, as is noted in several cases discussed above, state PUCs have limited the ability of a utility to change its rates in the years immediately following an acquisition as a part of the deal approval. In Box 2 below, additional detail is provided on how utility fixed costs and retail charges may be impacts by utility acquisitions, through the case of Central Hudson Gas & Electric.

Box 2. Discussion of Central Hudson Gas & Electric Rates Following 2013 Acquisition

The case of Fortis' acquisition of Central Hudson Gas & Electric in 2013 illustrates how prevailing state policy, combined with cost considerations, influences a utility's post-acquisition changes in retail rates component. As a condition of the acquisition, the New York State Public Service Commission ("PSC") required that the utility's delivery rates be frozen for a minimum of two years following the transaction. However, in the subsequent 2015 rate case after the two-year rate freeze, the NY PSC approved an 8% and 9% rate increase in the electricity rates for the residential sector in the fourth and fifth years after the acquisition. The utility argues that this rapid rise in rates is justified because the rate freeze only delayed the payment of costs into the future, and thus higher rates were justified to remunerate those costs.

Moreover, the fixed monthly component of the residential rate remained fixed, despite a petition by the utility to increase it to $29 from $24 dollars. The PSC primarily cited that the prevailing Reforming the Energy Vision ("REV") initiative in New York would likely reform the rate structure within the three-year rate-period, and thus changes in the rate were unnecessary at this time. Thus, the increase in the residential rate will come solely from the volumetric portion of the tariff.

Source: State of New York Public Services Commission, "Order Approving Rate Plan," CASE 14-E-0318, June 17, 2015, available at: https://www.cenhud.com/pdf/rateplan.pdf, p. 57.

3.3 Impacts of transactions on utility credit ratings

This section summarizes the impact of M&A activity on the credit ratings of utilities. Using data from the Moody's credit rating agency,[26] we assessed the changes in credit ratings experienced by utilities in our dataset that have been subject to M&A activity. Data is not available in all cases, either because Moody's has withdrawn ratings or does not track a particular utility, the nature of a transaction makes a direct comparison of pre-and-post credit ratings impractical,[27] or there is not adequate post-transaction data to use to draw a comparison. Therefore, this analysis is limited to a sample of 15 utilities. Due to limited data availability and the impracticalities of comparing pre- and post- transaction credit ratings for acquisitions that entailed a change in ownership model, all of the transactions discussed in this section are IOU-only transactions and did not involve a change in utility ownership model.

Credit ratings were compiled through the third year following a transaction (or the most recent year for which data is available). While over half of these utilities experienced a change in credit

[26] We also collected available credit ratings information from S&P, but for simplicity used only Moody's data in this analysis, which offered a greater amount of available data.

[27] For example, before-and-after credit ratings cannot be directly compared in the purchase of Alliant's Minnesota service territory by a coalition of twelve cooperative utilities, and Algonquin Power and Utilities' purchase of Sierra Pacific Power's small California service territory is excluded as it would not be sizeable enough to impact the credit rating of such a large utility holding company.

rating following the transaction, these were roughly split between credit rating downgrades and upgrades, yielding inconclusive evidence as to the impact of M&A activity on utility creditworthiness. "Ring fencing" mechanisms are used generally in the industry to protect subsidiary credit ratings from parents, or unregulated subsidiaries from regulated arms, and vice-versa, and these techniques may also isolate credit ratings from M&A impacts.[28]

Figure 9 below shows the range of credit ratings attributed to the impacted utilities in the year before a M&A transaction, as well as the rating in the third year following a transaction or the last data year available. Before the transaction, most utilities were spread across the medium grade (Baa) ratings, indicating moderate credit risk.[29] Smaller numbers of utilities were attributed upper-medium grade (A) and high grade (Aa) ratings, indicating low and very-low credit risks. By the end of the analysis period, credit ratings had slightly converged towards the middle grades, with fewer higher- or lower-rated utilities among those sampled. There was minimal change in the average credit rating, however, with the median rating improving only slight from Baa1 to A3.

As a point of reference, HEI has a current Moody's credit rating of Baa2,[30] having been downgraded from Baa1 in August 2016. Neither KIUC, nor HEI's subsidiaries namely Hawaii Electric Light Company, or Maui Electric Company have a Moody's credit rating.

[28] Mitchell et al, "Commission Staff Analysis of Ring-Fencing Measures for Investor-Owned Electric and Gas Utilities", Feb 2005, Maryland PUC.

[29] An overview of Moody's credit ratings may be found at: https://www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_79004

[30] As of October 2017.

Figure 9. Credit Ratings of Acquired Utilities Before and After Acquisition

Acquired/Merged Utility	Year	New Parent Company	Outgoing	Incoming	1 Year Prior to Transaction	3 Years Post Transaction
UNS Electric	2014	Fortis Inc	Investor Owned	Investor Owned	Baa2	A3
Sierra Pacific Power	2013	MidAmerican Energy Holdings Co	Investor Owned	Investor Owned	Baa3	Baa1
Central Hudson Gas & Electric	2013	Cascade Acquisition Sub Inc (Fortis)	Investor Owned	Investor Owned	A3	A2
Western Massachusetts Electric Co (WMECO)	2012	Northeast Utilities	Investor Owned	Investor Owned	Baa2	A3
Southwest Public Service Co (Lubbock service territory)	2010	Lubbock Power & Light	Investor Owned	Municipal		A1
Acquila, Inc	2008	Black Hills Power Inc	Investor Owned	Investor Owned	Baa2	Baa2
Texas - New Mexico Power	2007	PNM Resources	Investor Owned	Investor Owned	Baa3	Baa3
Union Light, Heat & Power Co	2006	Duke Energy	Investor Owned	Investor Owned	Baa1	Baa1
Central Illinois Light Co	2003	Ameren Corp	Investor Owned	Investor Owned	A3 *-	Baa2 *-
Louisville Gas & Electric Co	2000	PowerGen PLC	Investor Owned	Investor Owned	Aa3	A2
Commonwealth Electric Co	1999	NSTAR	Investor Owned	Investor Owned		A2
Central Illinois Light Co	1999	AES Corporation	Investor Owned	Investor Owned	Aa3 *-	A3 *-
Interstate Power Co	1998	Alliant	Investor Owned	Investor Owned		A2
Wisconsin Power & Light Co	1998				Aa3	Aa3

Source: Moody's. Data not available for all utilities.

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During the four-year period covering one year prior to a transaction and three years post a transaction, 60% of the evaluated utilities underwent a change in credit rating – five experienced an upgrade in credit rating, and four experienced a downgrade. The utilities that experienced the greatest upgrades were UNS Electric (Baa2 to A3), WMECO (Baa2 to A3), and Sierra Pacific Power (Baa3 to Baa1). The utilities that experienced the greatest downgrades were Central Illinois Light Co (which was involved in two transactions, falling from Aa3 to A3 after the first and from A3 to Baa2 after the second), and Louisville Gas & Electric (Aa3 to A2). Overall, the utilities in the sample experience a combined upgrade of eight tiers and a combined downgrade of 8 tiers, yielding no net change.

This investigation yields mixed results regarding the impact of M&A activity on the creditworthiness of electric utilities. While there are ready examples of utilities which both experienced an upgraded or downgraded credit rating in the wake of an acquisition, the results of this review do not allow for us to draw conclusions on the factors that inform such a shift in creditworthiness. The results are also mixed, and thus inconclusive, in instances in which the credit rating of the acquiring company was higher than the target company.[31]

3.4 Comparison of utility book value and acquisition costs

The following section will evaluate the relationship between the book value of the assets owned by a utility company and the ultimate cost of acquiring that utility. Our primary data source for this analysis is the Thompson Reuters Corporation, which provides information on both book value per share and initial offer per share of past utility acquisitions.[32] To develop a dataset that was suitable for this analysis, we incorporated information regarding utility acquisitions not otherwise included in this scope (typically those larger in size than utilities serving Hawaii's counties), in addition to utilities discussed in the sections above.

Our analysis relies on the initial offer price per share versus the book value per share, which offers a comparable ratio across similar industry transactions for equity value and is consistently available in the Thomson Reuters database over the last 20 years. It should be noted that in some cases, the data was often inconsistent with regards to book value, introducing methodological complications for comparing the initial acquisition cost versus the final acquisition cost.

Moreover, initial total acquisition cost estimates are often missing from the data, with initial offer price per share only being part of the total acquisition cost. With that noted, many of the initial offers per share remained unchanged in the finalized transaction. However, we have highlighted

[31] The dataset of transactions with Moody's ratings for both the acquiring and target companies revealed two instances in which an acquiring company possessed a higher credit rating than the target company, and subsequent improvement in the target utility's credit rating during the three years after the transaction. In one instance, the credit rating of the target company by a higher-rated acquiring company became worse. The other seven instances with available data revealed that the credit rating of the acquired company either stayed the same, or the acquiring company possessed an equivalent or lower credit rating than the target company.

[32] The definition of book value, otherwise referred to as net tangible assets, refers to the assets less the liabilities, and less any intangible assets, such as goodwill (inclusive of brand recognition, customer relations, and other similar factors) and intellectual property. It is theoretically the value of the company, if it is completely liquidated and the liabilities are repaid. It acquires "per share" status when it is divided by the total amount of outstanding common shares of the company. The offer price per share is the market price given by the acquiring entity per common share.

some of the factors that may make the initial acquisition cost (as opposed to simply the initial offer price per share) vary substantially from the final acquisition cost, as highlighted by the KIUC acquisition of Kauai Electric. These variables are particularly context specific, and should be evaluated on a case-by-case basis.

Figure 10 below illustrates a sample of the ratios of offer price to book value for thirty past energy utility acquisitions over the past 20 years where such data is available. Of these, five acquisitions (Bangor Hydro-Electric, Cap Rock, Central Vermont PSC, and Central Hudson Energy Group), were of a total size similar to a utility active in Hawaii, and these are denoted by a darker shade in the figure.[33] Because of this small sample, the below analysis discusses both the group of five utility transactions of a similar total size as a Hawaii utility as well as the broader group of 30 transactions.

The price to book ratio is a commonly used metric in financial analysis, typically used in the stock market to indicate the value that a market will place on stock, or equity, relative to its book value. As illustrated, this ratio generally tends to fall between 1 and 2.5, with the average of all 30 transactions falling at 1.91 and the average of the five size-qualified transactions falling at 1.63.[34] In other words, the price offered to acquire utilities is consistently greater (by 95% or 63%) than the sum theoretical value of utility assets. This conforms with prior research on the acquisition cost of utilities.[35]

As a point of reference, NextEra's proposed acquisition of HEI included an offer price per share of $33.39, which was determined through the average of the high and low prices per share of HEI common stock as reported on the New York Stock Exchange on January 5, 2015.[36] Applying this offer price to HEI's most recently published book value per share $19.08 yields an offer price to book value ratio of 1.75, in line with the average value derived from the above analysis. However, despite the similarities between the average price-book ratio and the NextEra offer price, the predictive power of this figure is limited and should not be treated as a foolproof metric for actual valuation of utility assets, which can be based on a variety of factors in addition to the theoretical value of assets.

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[33] Other sections of this report include individual utilities that are within this study's size limitations despite being a part of a larger corporation of utility holding company (for example, the sale of NV Energy, which included the sale of Sierra Pacific Power, which is approximately the same size as HECO Companies). However, as this portion of the analysis specifically assesses the purchase price of a utility, only those transactions where the total sale price is expected to be of a similar size as that of a Hawaii utility are included.

[34] While Cap Rock Energy is included in this analysis, this transaction differs from the others in that it involved a cooperative forming an IOU for the purpose of purchasing the utility's assets. Therefore, the price determinants of this sale over price in this case were very different from others, which may contribute to a lower price-book ratio. Excluding cap rock, the average ratio of size-qualified utility transactions is 1.78.

[35] For example, see the Massachusetts Department of Energy Resources, "Municipal Utility Study: Technical Report," 2010, p. 19, available at: http://www.mass.gov/eea/docs/doer/publications/doer-municipal-utility-rpt.pdf.

[36] Form S-4 registration Statement, NextEra Inc., January 8, 2015, available at: https://www.sec.gov/Archives/edgar/data/753308/000119312515005172/d846219ds4.htm

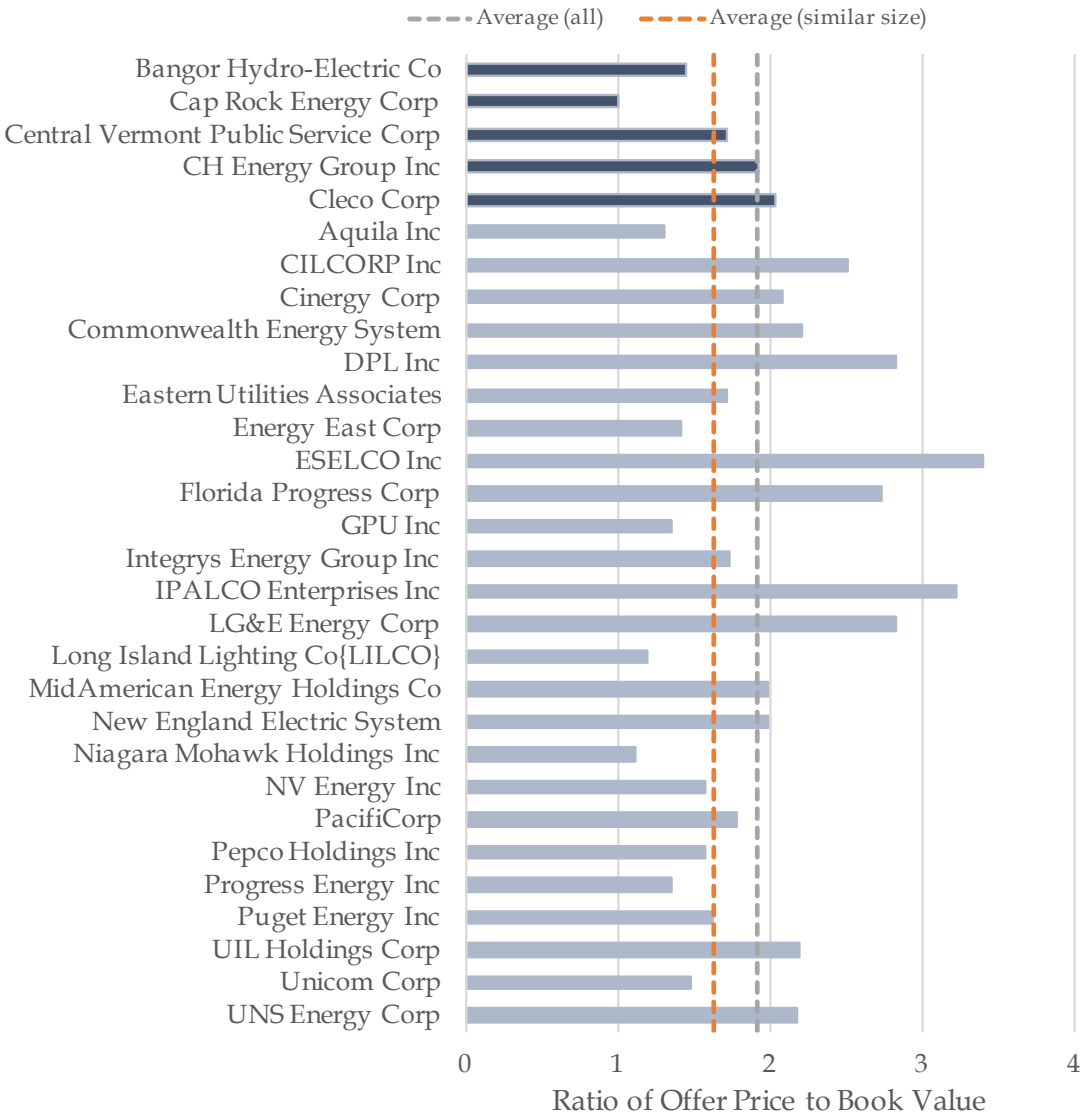
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While the ratio of offer price to book value can be an instructive first-order metric, it is important to contextualize this relationship in the range of context-dependent factors that can impacts acquisition cost, which may include:

- competition for the acquisition;
- the financial and business circumstances of the acquirer;
- intervention by the regulator (in terms of allowable return on equity, rate regulation, etc.);
- willingness of the seller (i.e. whether it is a "friendly" or "hostile" acquisition);
- determinations of "fair valuation," among other issues.

"Fair valuation" for an acquisition cost can be particularly challenging to determine. While examining book value ratios across similar transactions can serve as one potential metric in a broader market-based valuation, as mentioned above other valuation approaches include income generation, or cost-based approaches (such as the historical cost, or replacement cost of assets) that offer alternative perspectives on specific utility assets that avoid some of the comparative challenges mentioned above. Market-based approaches can also consider the acquisition cost versus a range of other metrics, such as the number of customers, rather than book value. As noted the textbox below, the acquisition of Kauai Electric by KIUC in 2002 illustrates several these factors at play.

Figure 10. Ratio of Offer Price to Book Value per Share of Selected Utility Acquisitions



Source: Thompson Reuters SDC Platinum Mergers and Acquisitions database; n=30 acquisitions

In addition, the acquisition cost relative to the book value of the asset may also be differentiated by the subsection of the assets under consideration, each of which are likely at various stages of depreciation. It is possible that generation assets may have a different return on equity than transmission and distribution. Acquisition bids for generation may have a potentially higher ratio to the book value if the return on equity is higher. Characteristics of assets located on each of Hawaii's islands and counties – such as the relative states of depreciation of assets on each island – may differ. As noted, much will also depend on the regulator and the allowable return on equity.

Box 2. Case: Book Value and Acquisition Costs of Kauai Electric, 2002

The book value of assets of Kauai Electric, as determined by the Hawaii PUC at the time of the acquisition, was approximately $180 million. KIUC decided to offer a bid of $270 million, which was over book value at a 1.5 ratio. While this was not the highest bid received by Kauai Electric, it was accepted because the utility believed that KIUC's finances were in better order than the competitor. However, the PUC rejected this deal, fearing that KIUC would take on too much debt. The subsequent offer was reduced to $217.5 million, which included an acquisition premium of approximately $37 million, or approximately a 1.2 ratio over book value. In this case, the initial acquisition cost was substantially reduced due to intervention by the regulator, due primarily to a concern that excessive debt would impact the rates of KIUC to an unacceptable degree.

In the case of an acquisition of the entirety of the utility, the acquirer assumes those liabilities (specifically, debt), which have presumably been utilized to increase the value of the company in some way other than simply being held as cash. In contrast, the book value subtracts liabilities, offering a figure of the net asset value *after* all debts are paid off. Moreover, the value from that debt can be larger than the debt owed, increasing the value of equity. For the purposes of determining the total acquisition cost, "enterprise value" is another important measure, which includes the value of equity, plus net debt, minus any cash holdings. The enterprise value offers a figure that is much more closely equated to the final acquisition cost than the book value, because an acquiring company will assume those debts.

Finally, all of the mergers and acquisitions included in the above analysis were friendly takeovers. Across the entire Thomson Reuters database (which includes many non-utility energy transactions), friendly takeovers accounted for 94% of all transactions for which data is available.[37] The acquisition cost of hostile takeovers would likely be higher than a friendly takeover, in part to greater transaction costs (such as litigation fees), or defensive strategies such as the acquisition target raising the stock price to make the hostile acquisition costlier. This may cause another significant divergence in the final acquisition cost versus the value of the asset.

[37] The other mergers and acquisitions are not necessarily hostile; they can also be neutral, or not suited to any particular classification.

4 Data sources and approach

The following section outlines the sources for our data and our methodology for compiling this data into a final list of applicable M&A activity. To develop a dataset of qualifying M&A transactions, we relied on two primary sources:

1) The **Thompson Reuters SDC Platinum Mergers and Acquisitions** database, which contains information from 2700 energy industry M&A transactions from 1980-present. The Thompson database includes typical stock trading information for the transactions as well, including book value, acquisition value, and other factors, though in many cases this information is not available for a particular transaction.

2) The **U.S. Energy Information Agency ("EIA")** annual utility reporting database (EIA-861 Database). This database is formed via an annual survey of U.S. electric utilities by EIA. The database contains information on utility customers, sales, revenues (from which average rates may be derived), distribution system capacity, and other factors. The database also contains limited information on electric utility M&A activity. Annual reports are available as far back as 1990, though certain data fields have not been available for the full history of the survey.

To compile a final list of M&A transactions to analyze in this dataset, we used information available in the Thompson Reuters M&A database to filter the data down to deals that likely included an electric utility transaction. For many records, we performed a manual check to confirm that the data was truly a utility transaction (many M&A deals included utility actors, but related to unregulated competitive retail businesses, individual power generation assets, or other business components). As many of the resulting acquired entities were utility holding companies which in turn owned several utility subsidiaries, we then expanded our list in order to identify the actual regulated utilities that were included in each transaction. Following this step, we mapped the Thomson Reuters data to the EIA-861 database to obtain utility size information (using the total number of meters served as a proxy for size). Using the count of utility customers for each utility, we then filtered the list of utility transactions again to identify utilities that were approximately the same size as a utility serving a county in Hawaii. To come up with utilities of a comparable size to Hawaii's utilities we included any utilities with customer counts from roughly 25,000 (25% less than the number of customers served by KIUC) to roughly 380,000 (25% more than the number of customers served by HECO Companies). In several cases, we included utilities that serve marginally more or fewer customers in our sample, particularly in cases where the acquisition of that utility entailed a change in ownership model. Finally, we cross-checked this list against the list of utility mergers and acquisitions recorded in the EIA-861 data to identify any missing qualifying transactions and performed a final manual check of each entry to confirm that it is in-scope. This resulted in a final list of 29 M&A transactions applying to 32 utilities (two transactions included multiple utility subsidiaries that fit within the parameters of this analysis).

To complete the utility transaction dataset, we then compiled the remainder of the necessary data from a variety of sources. In addition to customer counts, distribution capacity, annual retail

sales,[38] average retail rates both (defined simply as annual retail revenues divided by annual kWh sales), and utility ownership model were referenced from the EIA-861 database. Data on book value and acquisition cost came directly from Thomson Reuters, with book value data supplemented by reporting to the Federal Energy Regulatory Commission (FERC Form 1). Credit rating data was collected from Moody's for all utilities for which it is available. Finally, regulatory status for a particular utility was ascertained from a desk research into the regulatory practices in place in that state at that time, supplemented by a reference of the years of state utility restructuring efforts.

[38] Only bundled or delivery-only sales were included in this count, not supply-only sales.

5 Ownership structure impact conclusion

The preceding analysis offers several insights into the impact of changes in ownership and ownership model on stakeholders. These conclusions encompass: 1) the quality and applicability of data, and 2) relevant conclusions from that data, when available.

In terms of the quality and applicability of data, there are generally only a handful of cases in which there is prior precedent for utility acquisitions of this size, and most involve the merging or acquisition of the ownership of an IOU to another IOU ownership entity. The limited sample size of comparable transactions should induce caution in drawing conclusions on broader trends or relationships in changes in ownership model.

Despite the challenge of finding similar and adequately sized sample population for comparison, this analysis does provide important insights into the nature of utility acquisitions. These include findings that:

- With some exceptions or delays, the qualitative research included here shows that the regulatory oversight of utilities typically adapts when utility ownership models change.

- The analysis of electricity rates shows that acquisitions typically have a limited average impact on rates when controlling for contemporaneous rate changes among utilities in the same state (and therefore accounting for factors such as supply prices and inflation).

- The impact of utility acquisition on credit ratings is inconclusive, with utilities experiencing both credit upgrades and downgrades post-acquisition. These results were similarly inconclusive in cases in which the acquiring company possessed a higher credit rating than the target company.

- The offered sale price of utilities is, on average, nearly double the assessed book value of that utility. While there are many intervening factors that inform the purchase price of a utility, this indicates that book value may not be a reliable source of purchase price estimate.

6 Appendix: Scope of work to which this deliverable responds

Task 1.2.2 Empirical research and data to support the qualitative assessment of ownership models in Task 1.2.1.

CONTRACTOR shall provide a comparison of system acquisitions of comparable size in the United States within the past 20 years showing: 1) the outgoing and incoming ownership and regulatory models; 2) number of customers served; 3) capacity; 4) annual sales; 5) estimated book value; 6) initial acquisition cost estimate; and 7) actual acquisition cost for each system. CONTRACTOR shall also provide average fixed and variable average retail rates and credit rating before ownership change and each year after ownership change as data is available.

DELIVERABLE FOR TASK 1.2.2. CONTRACTOR shall provide its conclusions and all work to support the qualitative assessment in Task 1.2.1 with empirical research and data by analyzing the acquisition of utilities with a comparable size to the utilities serving each Hawaii county (i.e., plus or minus 25% in terms of customer count and/or installed capacity). CONTRACTOR shall describe how book value relates to acquisition cost, and the implications for customer rates and utility credit ratings in the wake of utility acquisitions. CONTRACTOR shall compare these trends to the ownership structure of these assets to determine if any ownership structures have a particularly negative or positive impact on customer rates, utility ratings, and/or asset values. CONTRACTOR shall provide data for transactions covering the last 20 years and average fixed and variable rates and credit ratings prior to and each year following the transaction. CONTRACTOR shall provide written narrative in MS Word and spreadsheets in MS Excel as well as an index of all source information used to generate the qualitative assessment.

Preliminary and High-Level Assessment of the Utility Ownership Models' Technical, Financial, and Legal Feasibility

Prepared for the Hawaii Department of Business, Economic and Tourism (DBEDT)

November 30, 2017

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. As a part of this engagement, this working paper provides a preliminary analysis of the technical, financial, and legal feasibility of each of the ownership models outlined in Task 1.1.1/1.2.1. For technical feasibility, this document assesses the financial, technical, and legal feasibility of each model. More specifically, to assess its technical feasibility, the Project team evaluated each model's ability to undertake utility responsibilities, achieve the long-term State energy goals, and meet the criteria of this study. For financial feasibility, this document analyzes the financial outlook of the acquired, or newly formed entity and its impact on ratepayers. Finally, this document outlines legal factors for governance, acquisition, or other miscellaneous items for each model that are essential to ensuring their success. Please note that this document offers a high-level assessment per the Task 1.2.3 description in the scope of services.

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List of acronyms

BTM	Behind-the-meter
CEO	Chief Executive Officer
DBEDT	Hawaii Department of Business, Economic Development, and Tourism
DER	Distributed energy resource
DSP	Distribution system platform
EAF	Equivalent availability factor
EFORD	Equivalent forced outage rate-demand
EFOF	Equivalent forced outage factor
FERC	Federal Energy Regulatory Commission
HAR	Hawaii Administrative Rules
HECO	Hawaiian Electric Company
HEI	Hawaiian Electric Industries
HELCO	Hawaii Electric Light Company
HERA	Hawaii Electricity Reliability Administrator
ICT	Information and communication technologies
IDER	Integrated distributed energy resource
IOU	Investment owned utility
IPP	Independent Power Producers
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International, LLC
LIPA	Long Island Power Authority
MCG	Meister Consultants Group
MECO	Maui Electric Company

NRECA	National Rural Electrical Cooperative Association
PPA	Power purchase agreement
PSC	Public Service Commission
PSEG	Public Service Enterprise Group
PUC	Public Utilities Commission of the State of Hawaii
PURPA	Public Utility Regulatory Policies Act
REV	New York's Reforming the Energy Vision
RUS	National Rural Utilities Service
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SB	Single Buyer

1 Executive summary

The following analysis provides a high-level assessment of the technical, financial, and legal feasibility of the seven ownership models introduced in Task 1.2.1. As a high-level analysis, it does not engage in a detailed engineering, financial, or legal feasibility study. Instead, this report assesses each ownership model considering its impact on the utility's ability to operate from an engineering, financial and legal perspective, and evaluates the overall feasibility of the ownership model in question. Following this assessment, Task 1.2.5 will narrow down the assessment of ownership models to three ownership models through a ranking and weighting process.

Some of the key findings of technical feasibility include:

- For most of the models, the role of the utility is unchanged in generation, transmission, and distribution, with the assumption that current regulations remain unchanged. Exceptions to this rule are the Single Buyer ("SB") and the integrated distributed energy resource ("IDER") models, which *require* state regulatory changes to allow for greater competition in generation. We did not contemplate any models that would require federal regulatory changes.

- All the models, except for grid defection, can theoretically meet the Public Utilities Commission ("PUC") standards for utility responsibilities. However, most utility models will also require additional hiring and workforce considerations, in part because of civil service restrictions or collective bargaining requirements (i.e. municipal utility [or "muni"] and potentially hybrid ownership models), management or salary concerns (i.e., cooperative ("co-op"), or to establish capacities or expertise in new areas (such as the IDER and SB models).

  In addition to hiring and workforce concerns, the IDER model would require some new investments in setting up the systems, protecting data, and facilitating market participation for customers, DER providers, and other service providers. Likewise, some additional investments are needed in the SB model, as discussed in Task 1.1.4. The SB model may also require an entity to audit and ensure that the SB is fulfilling its mandate, but this depends on its envisioned role and how it is implemented. However, the incumbent investor-owned utilities ("IOUs") already have a process for procuring power from IPPs that will bear some similarity to the SB model.

- Government involvement in utility ownership (in either the muni or the hybrid models) can have potential upsides in lowering the cost of capital, but could potentially have harmful effects on cost-efficiency if the utilities are not managed well.

Some of the key findings of financial feasibility include:

- The receptiveness of the acquired utility plays an essential role in determining the acquisition cost for the muni, hybrid, and co-op models. While utilities generally are open to acquisition with a sufficiently high purchase price, higher acquisition costs would

potentially be reflected in increased consumer rates, which is subject to PUC approval. In the SB and IDER cases, the proposed change can be mandated through regulation.

- Hawaii state governments and the municipal government generally have strong credit ratings to undertake the debt required to acquire assets at relatively lower cost. However, there are limits on municipal bond issuance, and the expenditures would be quite substantial in all cases, whether it is a hybrid or a municipal model. Thus, while the option of utility ownership is not foreclosed to Hawaii governments due to prior debt obligations, policymakers should consider the long-term costs that would be carried by Hawaii citizens.

- Some of the cost to achieve State goals under each ownership models will depend on specific characteristics that accompany each ownership model. For example, in the IDER model, final costs are determined by the regulation that accompanies the IDER. In the SB model, procurement practices and the competitiveness of the generation market have a significant effect on its cost-effectiveness. Operational costs and management efficiencies are an essential component of ongoing costs, and some models (i.e., muni or hybrid) arguably have poor incentives for cost control.

- Some ownership models, by being investor-owned, or through structural changes that they impose on the electricity market (i.e., greater competition in generation through SB or IDER models), have the potential of increasing overall access to capital to support State energy goals. However, this does not necessarily mean other models (i.e., co-op) are necessarily unable to access sufficient capital to achieve these goals.

- The muni and the co-op models potentially could have lower cost long-term debt financing. In the case of the co-op model, the co-op can access low rates at the long-term Treasury rate from sources such as the Rural Utilities Service. Muni can also take advantage of tax-exempt bonds, due to their association with a municipality, which can potentially be lower than market-based rates.

Some of the key findings for legal feasibility include:

- For the new IOU owner and the co-op models (assuming the co-op would be regulated to the same extent KIUC is currently regulated), no changes to legislation or regulation are needed since a prior legal framework is already in place. However, the new IOU owner would have to pass the scrutiny of the PUC and obtain the PUC's approval for a transfer of control. Grid defection would also not need any legal changes to happen; instead, high electricity prices and declining costs in solar and storage would incentivize defection.

- For the co-op model, one outstanding question is whether efficient co-ops could be created that qualify as "rural" according to federal definitions, which define "rural" with a 20,000-population cap for electricity program loans from RUS, or, whether, in the alternative, larger, island-wide co-ops could obtain financing at rates that would allow them to operate with efficiency comparable to that of other models.

- The muni model would journey into somewhat uncharted legal territory for Hawaii since municipalization is an unprecedented endeavor in Hawaii. The muni model would at a minimum require either a local referendum, county council action, or state action on municipalization. Additionally, if municipalization is pursued against the wishes of the incumbent IOUs, legal questions may arise regarding the intersection between the county's eminent domain powers and the PUC's right under state law to approve or deny the disposition of utility assets. These questions would need to be resolved by the courts, PUC, and/or state legislation.

- For the hybrid model, legislative action at the State level would be necessary to establish a holding company and allocate funding for the purchase of some shares of the utility. However, such a takeover of a private utility that is financially solvent would be largely unprecedented in the United States.

- For the IDER and the SB models, the PUC and/or legislature would likely need to make significant legal changes to establish the IDER model or to have a separate and independent[1] SB. The specific type of action varies widely depending on the specific model pursued. Legislative action may be necessary for the IDER model to establish an entity that can monitor and develop the market for distributed energy resources ("DERs"). For the IDER model there is a range of issues, from establishing new markets for value streams of DERs, changing rate setting methodologies to incentivize utility innovation, among many others. The SB and the IDER models would require some form of separation between generation and transmission and distribution assets.

[1] Independent can either be (i) independent of the other business entities within the HECO Companies or the KIUC (such as generation division, transmission division, etc.) or (ii) independent of the entire HECO Companies or the KIUC.

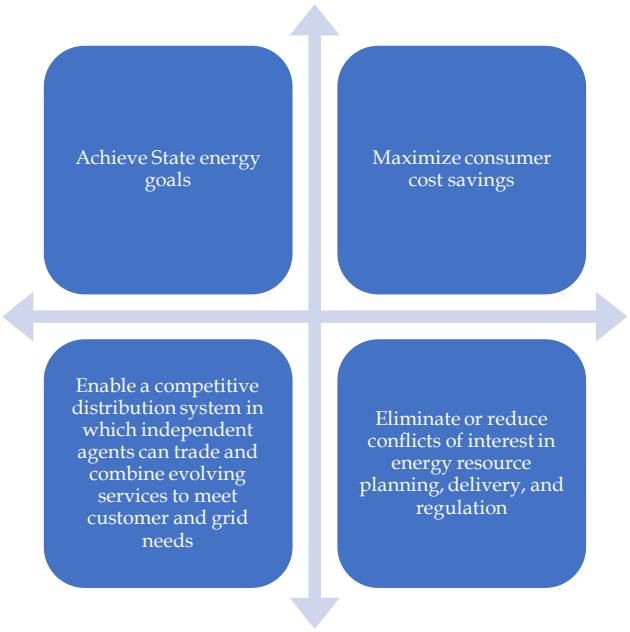
2 Introduction and scope

2.1 Project description

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. London Economics International LLC ("LEI") and Meister Consultants Group ("MCG," collectively "the Project Team"), through a competitive sealed proposals procurement,[2] were contracted to perform this study.[3]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[4] listed in Figure 1.

Figure 1. State's key criteria



Source: Scope of Services under Contract No. 65595

[2] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawai'i (RFP17-020-SID).

[3] Hawai'i Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[4] House Bill No. 1700 Relating to the State Budget.

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Boston, MA 02111
www.londoneconomics.com

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models and determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[5]

2.2 Role of this deliverable relative to others in the project

This deliverable is responsive to Task 1.2.3 in the project scope of work. This task requires a high-level assessment of the technical, financial and legal feasibility of each ownership model discussed in previous Tasks. These ownership models include investor owned utility ("IOU"), new parent under IOU, cooperative utility ("co-op"), hybrid utility with majority government-owned ("hybrid"), municipal utility ("muni"), single buyer ("SB"), integrated distributed energy resource ("DER") system operator ("IDER"), and grid defection/disperse ownership. A more comprehensive discussion of the recommended models will be performed for the following tasks:

Related to technical and operational feasibility of each ownership model:

- **Task 1.3.1. Identification of various steps, timeline, and costs required to change from the current ownership model to new models, including regulatory approvals.** The Project Team will determine the required steps and associated costs to change the ownership model and acquire the electric generation, transmission, and distribution assets.

- **Task 1.3.4. Assessment of how each ownership model impacts staffing of State agencies and stakeholders.** The Project Team will provide an estimate of the potential impacts a change in ownership model may have on the expertise and staffing requirements of related State agencies and stakeholders.

- **Task 1.4.3. Assessment of management structure and staffing plan needs under each ownership model, including an assessment on the oversight management and staffing needs for Public Utilities Commission and Consumer Advocate.** The Project Team will develop a management structure and staffing plan for each ownership model and include an estimate of the number of local jobs and associated salaries under each model.

Related to financial feasibility of each ownership model:

- **Task 1.3.3. Identification of risk for each ownership model, analysis of each risk, and assessment of the overall risk profile for each ownership option.** The Project Team will

[5] Hawaii Contract No. 65595. Scope of Services.

assess the following risk categories: financial risks, business risk, country/macroeconomic risk, operational risks, and governance risks.

- **Task 1.4.2. Economic evaluation of ownership and operation of each ownership model.** The Project Team will provide an economic evaluation of ownership and operation

- **Task 1.6.2. Analysis of how each ownership model would affect cash flows.** The Project Team will provide an analysis describing the cash flows of each model, including an overview of the accounting differences between ownership models (accrual vs cash basis) and the treatment of: 1) operations and maintenance expense; 2) taxes; 3) financing capital improvements; 4) depreciation; and 5) return on invested capital.

- **Task 1.6.3. Estimated revenue requirements under each ownership model through 2045; graphic comparing results.** The Project Team will provide the expected annual revenue requirement under each ownership model through 2045, including the identification of all major cost elements.

- **Task 1.6.4. Matrix comparing system average retail rates under each ownership model through 2045 for an average residential, commercial, and industrial customer.** The Project Team will forecast system average retail rates through 2045 under each ownership model.

Related to legal feasibility of each ownership model:

- **Task 1.3.2. Identification of legal changes needed to implement the proposed utility legal framework options.** The Project Team will perform a detailed analysis to identify the legal framework of the recommended ownership models, enumerate Hawaii laws and regulations that are necessary, and determine the changes to existing statute and regulations that are required.

3 Key concepts

In this Task, we conduct a high-level feasibility analysis of the technical, financial, and legal aspects of each utility ownership model discussed in previous work papers. Feasibility is defined as "the possibility that can be made, done, or achieved, or is reasonable."[6] These standards draw heavily from available literature and the guidelines of the PUC. More specifically, we looked at various statutes, PUC Decisions, and Orders. These include:

- Standards of review for utility acquisitions and changes in ownership models in the cases of (1) the acquisition of Kauai Electric by the Kauai Island Utility Cooperative and (2) the proposed acquisition of the HECO Companies[7] by NextEra Energy;
- The standards for electricity service as outlined in General Order No. 7 by the PUC;
- The performance metrics for electric utilities as outlined by the PUC;
- The responsibilities of the PUC as specified under Hawaii Revised Statute, particularly Title 15 "Transportation and Utilities," Chapter 269 "Public Utilities Commission;" and
- The "Inclinations" of the PUC for the clean energy vision of Hawaii as outlined in "Exhibit A: Commission's Inclinations on the Future of Hawaii's Electric Utilities."

In its decision on the HECO Companies and NextEra Energy, Inc. proposed merger, the Hawaii PUC provided guidance for any future merger or acquisition proceedings.[8] More specifically, it provided guidance on "key elements that would be necessary to meet the public interest standard in any future applications seeking a change of control of the HECO Companies."[9]

These key areas include the following as excerpted from the Order:

1) **Ratepayer benefits**: The merger or acquisition should provide ratepayer benefits that are meaningful, certain, and direct in the short-term, and that effectively and accountably

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[6] Cambridge Dictionary. Other dictionaries define it as such: Merriam-Webster "capable of being done or carried out;" and Oxford "the state or degree of being easily or conveniently done."

[7] The term "HECO Companies" refers specifically to Hawai'ian Electric Company ("HECO"), Maui Electric Company ("MECO"), and Hawai'ian Electric Light Company ("HELCO"). The analysis within this report is not intended to apply to the American Savings Bank ("ASB"), which is a subsidiary of HEI. In some cases, the term "HEI" (for Hawai'ian Electric Industries) is used to refer to the ownership entity of the HECO Companies.

[8] Hawaii Public Utilities Commission. *Order No. 33795 (Dismissing Application Without Prejudice and Closing Docket).*

[9] Hawaii Public Utilities Commission. *Order No. 33795 (Dismissing Application Without Prejudice and Closing Docket).* Appendix A – Commission Guidance for Any Future Merger or Acquisition Proceedings. P. 1.

insulate customers from bearing the costs of the merger/acquisition, transition, and integration.

2) **Risk mitigation:** Ring-fencing measures should protect the HECO Companies' customers from the impacts of possible bankruptcy or other major problems that may occur in the future concerning other members of an applicant's corporate family.

3) **Achievement of the State's clean energy goals**: The merger or acquisition should provide clarity on the applicant's positions on clean energy transformation and distributed energy resources with a clear affirmation of the Commission's guidance on these areas in the Inclinations and relevant subsequent related decisions.[10] The textbox below provides additional guidance on the relevant Inclinations of the Public Utilities Commission on the future of Hawaii's Electric utilities.

4) **Competition**: The merger or acquisition must demonstrate that their proposal will promote robust competition in Hawaii's energy markets. This entails competitive bidding and procurement processes that provide customer value, adheres to best practices, protects confidentiality, and is accompanied by appropriate oversight.

5) **Corporate governance:** The proposed corporate structure must ensure a meaningful, representative role for local governance and Hawaii stakeholders.

6) **HECO Companies' transformation**: The merger or acquisition must provide specific commitments that reflect the critical importance of transforming the HECO Companies into a customer-focused, cost-efficient, and performance-driven electric utility. This includes affordable and stable rates, as well as customer service and reliability.

As noted, this paper will not discuss in detail every standard described above. Future tasks under Tasks 1.3 to 1.6, will discuss in further detail the various steps for the formation and required legal changes, the HECO Companies' transformation, risk mitigation, and potential impact of ownership change on ratepayers amongst others. This document provides high-level insights on the potential factors that influence performance on the standards, which has been divided into technical, legal, and financial feasibility concerns.

"Inclinations" of the PUC on the Future of Hawaii's Electric Utilities

The PUC outlined several key inclinations on the future of Hawaii's electric utilities to guide utility business strategy, energy resource planning, and project review. These guiding principles include:

- **Creating a 21st Century Generation System:** Hawaii currently relies heavily on oil-fired electricity generation, which is expensive compared to modern, clean energy technologies. Utilities should move urgently to capitalize on cost-saving opportunities by modernizing electricity generation with clean and efficient resources on all islands.

- **Creating Modern Transmission and Distribution Grids:** future electric grids must be designed as advanced networks that integrate greater quantities of customer-sited distributed energy resources and offer customers increased opportunities to manage their energy usage.

- **Policy and Regulatory Reforms to Achieve Hawaii's Clean Energy Future:** the PUC noted that the HECO Companies "may not currently have the appropriate financial incentives" to achieve Hawaii's policy goals. In particular, "inherent financial conflicts" related to utility ownership of generation and related compensation frameworks result in a "lack [of] correct incentives to control power supply costs, aggressively pursue long term contracts with IPPs for new renewable energy projects, and expeditiously retire old, inefficient generation units." Utilities will need to transform their business models, such as by focusing on "energy delivery" and related grid modernization functions, rather than generation. Similarly, the PUC stated that it may need to transform regulatory frameworks, such as by setting up new financial incentive mechanisms, unbundling ancillary services from electricity pricing, and forbidding the ownership of new generation by utilities. These new business and regulatory models will enable utilities to meet rapidly changing customer, technical, and economic requirements.

Source: Hawaii Public Utilities Commission, "Exhibit A: Commission's Inclinations on the Future of Hawaii's Electric Utilities," Docket No. 2012-0036, Decision and Order No. 32052, filed on April 28, 2 014, ("Order No. 32052"), available at https://puc.Hawaii.gov/wp-content/uploads/2014/04/Commissions-Inclinations.pdf

3.1 Technical feasibility

Technical feasibility evaluates whether the ownership model in question enhances or detracts from the utility's ability to carry out the roles and responsibilities of an electric utility in the State. The PUC has identified the roles of an electric utility in various regulations and laws. These include providing adequate and reliable energy supply, avoiding interruption of services, complying with standards set by the PUC, and maintaining service quality, to name a few, as discussed in the textbox below.

Some of the Major Responsibilities of an Electric Utility (not exhaustive list)

PUC General Order No. 7 outlines the key standards for Electric Utility Service in the State of Hawaii. Moreover, the PUC has further outlined performance metrics that should accompany such standards. The following summarizes some of the key responsibilities of an electric utility, as well as the metrics for those responsibilities:

1. Provide an adequate and reliable electricity supply:

Rule 5.3.a of General Order No. 7 states that the generation capacity of the utility's plants, supplemented by electric power regularly available from other sources, must be sufficiently large to meet all reasonably expectable demands for service and provide a reasonable reserve for emergencies. The performance metrics for this include the Equivalent Availability Factor , the Equivalent Forced Outage Rate-Demand, the Equivalent Forced Outage Factor, and the ratio of IPP Energy/Net to System Energy. These are broadly used performance indices for availability of generation resources to provide power.

2. Avoid interruptions of service:

Rule 7.5 of General Order No. 7 establishes that each utility shall make reasonable efforts to avoid interruptions of service, but when interruption occurs, service shall be re-established within the shortest time practicable, consistent with safety. The performance metrics for this include the System Average Interruption Duration Index ("SAIDI") which measures the average interruption time for all customers served during a given period of time, and the System Average Interruption Frequency Index ("SAIFI") which measures the average number of interruptions experienced by all customers served during a given time period.

3. Meet quality of service standards:

The Hawaii PUC requires regulated utilities to continually achieve high quality of service standards. Quality of service includes aspects of customer service and technical services, involving both interactions and engagements between customers and HECO Companies. The performance metrics for this include the percentage of customer calls answered within 30 seconds and consumer transaction survey results.

Sources: Hawaii Public Utilities Commission, "Hawaii General Order No. 7," available at: https://puc.Hawaii.gov/wp-content/uploads/2013/04/General-Order-7.pdf ; Hawaii Public Utilities Commission, "Approving the Release of Performance Metrics, Directing that the Approved Performance Metrics be Posted to the Websites, and Directing the Parties to Develop Additional Performance Metrics," Order No. 32701, available at: http://dms.puc.Hawaii.gov/dms/DocumentViewer?pid=A1001001A15C12A92431G90153

As briefly discussed in Task 1.1.1/1.2.1, while many of the ownership models can be made to meet most or all the State's objectives, they differ regarding their effectiveness and the extent of regulatory intervention required. For example, the role of the utility in maintaining or owning generation assets might vary by model, implying regulatory unbundling of generation assets. In

that respect, certain ownership models, such as the SB and the IDER models, tend to be more "wires"-focused, and may also require additional responsibilities necessary for more transparent system operations, requiring the development of new utility functions and capabilities. As another example, hiring and compensation restrictions particular to certain models might inhibit the ability of the utility to retain the expertise necessary to perform its responsibilities.

In addition, the State has set specific energy goals. More specifically, Hawaii aims:

- to source 100% of the electricity from utilities from renewable energy by 2045;[11]
- to have a diversified energy portfolio that makes the best use of land and resources;
- to have integrated and modernized grids;
- to balance technical, economic, environmental, and cultural considerations;
- to leverage Hawaii's position as an innovation test bed; and
- to have an efficient marketplace that is beneficial to producers and consumers.[12]

For this purpose, this technical feasibility analysis considers whether the new ownership model can perform the responsibilities of an electric utility as directed by the PUC. With regards to the accomplishment of the State's energy goals, it is assumed that most of the models will be able to achieve them given that they are directed by the PUC to do so, and it is one of the criteria set by the PUC for the entity to move forward with the acquisition of or merger with the incumbent utility, as stated in the Commission Guidance for Any Future Merger or Acquisition Proceedings.[13] Moreover, on April 18, 2018, the PUC opened an investigative docket to consider Performance-Based Regulation ("PBR"), which would incentivize the performance of the IOUs in Hawaii according to defined metrics that reflect the public interest. This regulatory framework could apply to the reformed IOUs under each of the ownership models outlined; however, the proposed PBR framework notably excludes coops from its purview. That noted, this analysis does not provide an engineering and systems analysis of technical feasibility, and is intended solely to provide a high-level perspective on the technical feasibility of each ownership model.

The key questions regarding technical feasibility that the Project Team will answer include:

- Will this new ownership model change the roles and responsibilities of the incumbent electric utility?

- Would this require additional infrastructure or capabilities?

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[11] HRS § 269-92.

[12] Hawaii State Energy Office, Hawaii Department of Business, Economic Development, and Tourism, "Energy Policy Directives," March 2017, available at: https://energy.Hawai'i.gov/wp-content/uploads/2011/08/EnergyPolicy_1pgr_rev-Mar2017.pdf.

[13] Hawaii Public Utilities Commission, *Order No. 33795 (Dismissing Application Without Prejudice and Closing Docket)*, available at: https://puc.Hawai'i.gov/wp-content/uploads/2016/07/FINAL.ORDER_.33795.Docket2015-0022.pdf

- Will the ownership model be able to comply with the reliability, adequacy, and quality of service standards established by the PUC over the short and long-term?

3.2 Financial feasibility

Financial feasibility evaluates the financial characteristics of the ownership model. Since "financial feasibility" can encompass many factors, this analysis is limited to the financial impacts on ratepayers and the acquiring entity. For the financial impact on ratepayers, this analysis considers the various economic benefits or costs that could accrue to ratepayers over time. For the acquiring entity, the analysis evaluates the ownership model's access to capital to provide the upfront funding necessary to form the new utility ownership model and sustain the operations of an electric utility.

Of the State's criteria for ownership models, maximizing consumer cost-savings is an essential factor which has been echoed in feedback from stakeholders. Moreover, the criteria outlined above are closely intertwined. Different costs of capital will likely be internalized by ratepayers or through taxpayers through rates or other forms of subsidies. The ownership model under consideration should ensure that such costs are minimized to efficiently deliver benefits to ratepayers.

The key questions regarding financial feasibility that this assessment will answer include:

- What are the relevant factors for determining whether the transition to the new model is financially feasible (i.e., does any new owner of all or part of the incumbent utility have access to capital to purchase the utility and operate it? Is the cost of the acquisition reasonable)?

- What financial benefits or costs would accrue to ratepayers or taxpayers?

3.3 Legal feasibility

Legal feasibility assesses whether the transition to another ownership model is legally possible given the current laws, statutes, and regulations. This analysis encompasses legal requirements that must be fulfilled for the ownership model under consideration for 1) the initial acquisition or establishment and 2) the subsequent governance of the ownership model. Such factors will necessarily vary according to the ownership model in question. Our analysis seeks to identify any potential "fatal flaws," or significant legal challenges, to the transition in question. In doing so, our analysis draws heavily upon the regulatory frameworks established by the PUC.

The key questions regarding legal feasibility include:

- Is there an existing legal framework for this ownership model? Are any legal or regulatory changes necessary for this ownership model?

- What governance structures would be necessary for this new ownership model to function as intended?

- Are there any additional legal factors for the viability of this new ownership model?

The answers to these legal feasibility questions are controlled by the diverse sources of federal, state, and local law that govern Hawaii's electricity sector. The authorities that form the overarching legal framework for our legal feasibility analysis include the following:

*Public Utility Franchises***.** Prior to the enactment of state and federal legislation for the regulation of public utilities, most U.S. public utilities were regulated primarily by the terms of franchises granted by municipal governments.[14] A franchise was similar to a corporate charter, but was associated with the right to operate in a particular type of business, the entry to which was restricted.[15]

The regulatory history of Hawaii's electric utilities is somewhat unusual, in that they were established before Hawaii became a U.S. state, and before its counties had been established. HECO's franchise and other Hawaii electric utility franchises have been amended and replaced several times over the years, and the current franchises are state legislative enactments.[16] The franchises are non-exclusive, and revocable at will by the state legislature.

When the "franchise phase" of electric utility regulation gave way in the early 20th century to regulation by state and federal commissions, Hawaii's electric utility franchises were harmonized with the new regulatory commission-led system. Specifically, revisions were made to the franchises to clarify that they would be subject to PUC regulation,[17] and Hawaii Revised Statutes

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[14] CHARLES F. PHILLIPS, JR. THE REGULATION OF PUBLIC UTILITIES 120 (Public Utilities Reports, Inc. 1988).

[15] *Morita v. Pub. Utilities Comm'n of the Territory of Hawaii*, 40 Haw. 579, 583–84 (1954) ("A franchise is a special privilege conferred by governmental authority on corporations, on individual persons or associations to do something otherwise legally incompetent, such as the right to operate a ferry, a railway, a street railway system, and to lay tracks and poles along public streets, etc. Unfortunately, much confusion has resulted because the term "franchise" has frequently been used with two meanings: one, the right to be a corporation, because frequently the franchise and the creation of the corporation occurred under one legislative act; the other, special rights, privileges and powers granted to the corporation (or to an individual) by legislative act. The special rights granted are not ordinarily part of the corporation; they can be granted to an individual with the same legal force and effect as to a corporation.")

[16] The franchise agreements are available in the Applicants' Response to LOR-IR-38, Docket No. 2015-022, or the regulatory proceeding for the NextEra merger. HECO's franchise appears at the Revised Laws of Hawai'i of 1925, pages 1980-85, as amended by Act 134 of 1961 and Act 88 of 1974. HELCO's franchise is Act 130 of 1963. MECO's Maui franchise is Act 12 of 1991. MECO's Lanai Franchise is Act 54 of 1988. MECO's Molokai Franchise is Act 147 of 1989.

[17] For example, section 16 of HECO's franchise provides that "This franchise, and the person or corporation holding the same, shall be subject as to reasonableness of rates, prices, and charges, and in all other respects to the provisions... creating a public utilities commission, and all amendments thereof, for the regulation of the public utilities in said Territory, and all of the powers and duties expressly conferred upon or required of the superintendent of public works

("HRS") 269-7.5(d) clarified that existing franchised utilities need not seek new "Certificates of Public Convenience and Necessity" ("CPCNs") from the PUC. However, Hawaii law does not appear to conclusively establish whether a ***new*** electric utility would require a new franchise from the Hawaii legislature (or a municipality), or whether it is sufficient for such a new utility to obtain a CPCN from the public utilities commission.

*State Public Utilities Regulation - HRS Chapter 269***.** HRS Chapter 269 establishes the Public Utilities Commission of the State of Hawaii ("PUC"), and delegates to it the power to regulate "public utilities," defined in HRS § 269-1 include (among other things) "every person who may own, control, operate, or manage . . . whether under a franchise, charter, license, articles of association, or otherwise, any plant or equipment, or any part thereof, directly or indirectly for public use . . . for the production conveyance, transmission, delivery, or furnishing of light, power, heat, cold, water, gas, or oil." Hawaii Supreme Court authority establishes that entities that provide electricity to just one customer (such as an IPP that sells electricity at wholesale to a utility) do not qualify as a "public utility" under this test. Entities that do qualify as public utilities (such as the HECO Companies) are required to apply to the PUC for a CPCN prior to initiating service, may not charge prices in excess of the rates set by the PUC according to the procedures set forth in HRS Chapter 269, and are subject to the PUC's investigatory and "general supervision" powers. [18]

HRS Chapter 269 gives the PUC jurisdiction or potential jurisdiction that will be relevant to many of the models discussed below, including the following:

- The PUC has jurisdiction to approve or reject many proposed transfers of ownership in Hawaii utilities, such as transfers of ownership to or mergers with new investor-owned

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or the courts by said act creating said franchise are hereby conferred upon and required of said public utilities commission."

[18] HRS Chapter 269 is one of numerous similar state regulatory commission laws passed across the nation in the first decades of the 20th Century in response to the special problems first posed by the railroads, and soon discovered again in the gas, electricity, telephone, and other industries. In these "natural monopoly" industries, competition was observed to be ineffective; the industries showed a tendency to consolidate into monopoly, and monopoly appeared to be more productively efficient than multiple duplicative railway lines or electricity grids. The goal of public utilities regulation as implemented by HRS Chapter 269 was to facilitate the beneficial aspects of monopoly in such industries, while protecting customers from high prices with cost-of-service ("cost plus") rates calculated by professional independent commissions. *See generally* Richard A. Posner, *Natural Monopoly and its Regulation*, 21 STAN. L. REV. 548 (1969); Scott Hempling, REGULATING PUBLIC UTILITY PERFORMANCE: THE LAW OF MARKET STRUCTURE, PRICING, AND JURISDICTION 12-32 (2013); Alfred E. Kahn, THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS (2d Ed. 1988, 1st Ed. 1970-71); CHARLES F. PHILLIPS, JR. THE REGULATION OF PUBLIC UTILITIES (Public Utilities Reports, Inc. 1988).

utilities, cooperatives, or, potentially, government-controlled private holding companies.[19]

- The PUC has jurisdiction to approve or reject the disposition of utility assets, such as the sale of utility assets to a new municipal utility.[20]

- The PUC has jurisdiction to regulate the pricing and generally supervise the entities that would result from implementation of some but not all of the models below. Specifically, the PUC ***must*** regulate investor owned utilities, ***may*** regulate cooperatives, [21] and ***may not*** regulate municipal utilities.[22]

- The PUC may review contracts between public utilities and "affiliated interests."[23]

The Federal Power Act ("FPA"). In 1935, Congress, enacted the FPA, which gives the Federal Energy Regulatory Commission ("FERC") jurisdiction over "the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce."[24] In most of the mainland U.S., FERC has jurisdiction over the interconnection of power plants to transmission systems, the rates charged by IPPs in wholesale markets, and the rates charged by transmission owners for transmission service; state public utilities commissions retain jurisdiction over retail rates. However, U.S. Supreme Court precedent establishes that since Hawaii electricity systems are wholly intrastate, FERC does not have jurisdiction over wholesale transactions or interconnection in Hawaii.[25]

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[19] HRS§ 269-18 ("No public utility corporation shall purchase or acquire, take or hold, any part of the capital stock of any other public utility corporation, organized or existing under or by virtue of the laws of the State, without having first been authorized to do so by the order of the public utilities commission").

[20] HRS § 269-19 ("[N]o public utility shall sell, lease, assign, mortgage, or otherwise dispose of or encumber the whole or any part of its road, line, plan, system, or other property necessary or useful in the performance of its duties to the public, or any franchise or permit, or any right thereunder, not by any means, directly or indirectly, merger or consolidate with any other public utility without first having secured from the public utilities commission an order authorizing it so to do do.")

[21] HRS § 269-31 ("The public utilities commission . . . may waive or exempt an electric cooperative from all or any or all requirements of this chapter or any applicable franchise, charter, decision, order, rule or other law upon a determination or demonstration that such requirement or requirements should not be applied to an electric cooperative or are otherwise unjust, unreasonable, or not in the public interest.")

[22] HRS § 269-31 ("This chapter shall not apply to . . . public utilities owned and operated by the State, or any county, or other political subdivision.")

[23] HRS § 269-19.5.

[24] The relevant sections of the FPA are codified at 16 U. S. C. § 824 et seq.

[25] *See, e.g., New York et al. v. Fed. Energy Reg. Comm'n*, 535 U.S. 1 (2002).

Public Utility Regulatory Policies Act of 1978 (PURPA). In 1978, Congress passed PURPA, which (among other things) requires electric utilities to interconnect with certain types of independent power plants and purchase their energy at the utility's avoided cost.[26] PURPA jurisdiction does extend to Hawaii, and the PUC has promulgated rules setting out procedures for the exercise of PURPA "must purchase" rights, which are codified in Hawaii Administrative Rules ("HAR") Chapter 6-74. However, it has been a number of years since PURPA has been utilized by an IPP in Hawaii, and the details of how a PURPA avoided cost would be calculated are therefore uncertain. In particular, PURPA avoided cost calculations would need to be harmonized with the PUC's Competitive Bidding Framework (described below) and HRS § 269-27.2, which provides that any just and reasonable renewable energy rate established by the PUC "shall be accomplished by establishing a methodology that removes or significantly reduces any linkage between the price of fossil fuels and the rate for the non-fossil fuel generated electricity." In addition, the FERC decision, *In Re California Public Utilities Commission*, also allows states increased flexibility to set resource-specific avoided cost rates through PURPA.[27] These resource specific rates can allow projects to receive rates aligned with their cost of generation and not based on an average cost to the utility across multiple generation asset types. In PURPA cases arising from other states, FERC has held that state commissions need not base avoided cost on short-term calculations of the cost of operating utility-owned generation (which in Hawaii is linked to oil prices), but may instead base avoided cost calculation on the results of competitive bidding proceedings or long-term avoided cost modeling.[28]

FERC Order 888 and 2000. In the 1990s, FERC used its powers under the FPA to issue a series of major orders intended to redress "undue discrimination" by electric utilities on a nationwide basis. FERC's Order 888 required all transmission utilities to offer Open Access Transmission Tariffs for the "wheeling" of electricity over the utility's infrastructure, allowing IPPs to provide electricity to remote IOUs, municipal utilities, and, in some cases, large retail customers.[29] FERC's Order 2000 found that Order 888 had not gone far enough in remedying undue discrimination, and encouraged the organization of Regional Transmission Organizations. States in the Northeast, Texas, California, and several other states responded to this mandate by setting up nonprofit, federally-regulated Independent System Operators, which took over control of

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[26] Pub. L. No. 95–617, 92 Stat. 3119 (1978) (codified as amended in scattered sections of 15, 16, and 30 U.S.C.).

[27] 133 FERC § 61, 059 (2010).

[28] See, e.g. *Jersey Central Power & Light Co.*, 73 FERC ¶ 61,092 (Oct. 17, 1995); Timothy P. Duane, *Regulation's Rationale: Learning from the California Energy Crisis*, 19 YALE J. ON REGULATION 471, 485-87 (2002) (explaining how California eventually replaced uneconomic avoided cost PURPA rates with rates based on competitive bidding).

[29] FERC, Order No. 888, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, 61 Fed. Reg. 21,540, 21,546 (May 10, 1996) (hereinafter "Order 888").

transmission grids from utilities.[30] However, because FERC's jurisdiction does not extend to Hawaii, Hawaii utilities are ***not*** required to offer wheeling tariffs or to take other steps towards restructuring required by FERC's orders. The resulting significant differences between the electricity regulatory regime on the U.S. mainland and the electricity regulatory regime in Hawaii are an important "legal fact" that affects the set of options analyzed below.

The PUC's Competitive Bidding Framework. In 2007, after considering but rejecting the possibility of ordering industry restructuring on its own initiative, the PUC issued the Competitive Bidding Framework.[31] The PUC's goal was to create "a wholesale market model that includes equity and efficiency considerations, encouragement of competitive efficiency options and new technologies, lower costs through competition, more choices, reliable supplies, and a level playing field on which all generation options could compete." The Framework provides that when the HECO Companies desire to procure new generation over a certain threshold (e.g. 5 MW on Oahu), they must hold a PUC-supervised competitive bidding proceeding to determine whether the new generation can be procured more cost-effectively from an IPP than through utility ownership. Consequently, with few exceptions almost all[32] new generation developed in Hawaii since 2007 has been owned by IPPs rather than the utility, with the utility serving as the sole buyer of all IPPs' electricity under long-term Power Purchase Agreements ("PPAs").[33]

Hawaii Electricity Reliability Administrator ("HERA") law. In 2012, Hawaii enacted a law "to authorize the public utilities commission to perform necessary electric system reliability and grid access oversight functions, and to allow the commission to contract for the services of a Hawaii electricity reliability administrator to support the commission in carrying out those critical functions throughout the State."[34] However, the PUC has yet to promulgate rules under the HERA law, or to contract with a reliability administrator.

Hawaii Local Government law. Hawaii, unlike most other states, has only one level of local government. There is one county government on each of Oahu, Kauai, and Hawaii island; Maui County spans Maui island, Moloka`i, and Lanai. There are no separately-incorporated cities or other municipalities within these counties. Therefore, the county governments take on most the

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[30] FERC, Order No. 2000, Final Rule on Regional Transmission Organizations, 65 Fed. Reg. 810, 817-818 (Jan. 6, 2000) (codified at 18 C.F.R. § 35.34) (hereinafter "Order No. 2000").

[31] PUC Decision and Order No. 2258, issued June 30, 2006, in Docket No. 03-0372.

[32] Two exceptions are currently under development: HECO is developing a generation project at Schofield Barracks in collaboration with the Army, and a PV project at West Loch in collaboration with the Navy.

[33] However, most of these projects have been developed under waivers of the specific rules imposed by the Framework, rather than under fully Framework-compliant bidding procedures. SunEdison Utility Holding, Inc.'s Motion to Intervene, filed June 1, 2015, in Docket No. 2017-0077, at Exhibit A pp. 4-5 (calculating that as of 2015, only 2 projects had been selected vis Framework-compliant RFPs, with all of the rest (15+ projects) selected pursuant to waivers).

[34] Hawai'i Legislature's Act 166 of 2012, codified at HRS § 269-142 et seq.

governmental functions typically exercised by either cities or counties in other states (e.g. police and fire, road construction and maintenance, etc.). Additionally, the state government in Hawai`i takes on some functions handled by local governments in most other states. For example, Hawaii is the only state government that administers the state's public education system. Similarly, Hawaii has only state courts, no county-level courts.

Despite these differences, Hawaii's county governments have a legal status similar to those of local governments in the rest of the U.S. Local governments are considered constituent, subsidiary organs of the state government, which exercise powers only to the extent permitted by the state government.[35] The Hawaii state government, like many other state governments, has delegated "home rule" powers to its local governments, which gives Hawai`i counties a certain degree of autonomy. Specifically, Section 8.2 of the Hawaii Constitution provides: "Each political subdivision shall have the power to frame and adopt a charter for its own self-government within such limits and under such procedures as may be provided by general law." The Hawaii Supreme Court has interpreted this provision to mean that "Provisions of a charter or ordinance of a political subdivision of the state [such as a county] will be held superior to legislative enactments only if the charter provisions relate to a county government's executive, legislative or administrative structure and organization."[36] These "home rule" provisions affect the analysis of certain municipalization options, as described in more detail below.

Hawaii Eminent Domain Law. The Fifth Amendment of the U.S. Constitution forbids states from taking private property without just compensation.[37] However, like most states, Hawaii law provides a framework pursuant to which the state may take private property upon the payment of just compensation. HRS § 46-61 provides that "[e]ach county shall have the following specific powers: To take private property for the purpose of . . . public uses within the purview of section 101-2."[38] HRS Chapter 101 specifies the procedures under which counties, state agencies, or utilities can initiate eminent domain proceedings in state circuit court, and the criteria that govern courts' decisions regarding the valuation of assets taken in such proceedings. Together with the local government law and PUC statutes described above, this eminent domain law controls certain questions related to the options for transitioning an unwilling utility to the new models analyzed below.

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[35] Kenneth Vanlandingham, *Municipal Home Rule in the United States*, 10 WILLIAM & MARY L. REV. 269 (1968).

[36] *City & Cty. of Honolulu v. Ariyoshi*, 689 P.2d 757, 764 (Haw. 1984)

[37] The Fifth Amendment's takings clause also limits the ability of state public utilities commissions from setting utility rates that do not provide the utility with just compensation. *Munn v. Illinois*, 94 U.S. 113 (1877).

[38] In the 1980s, Hawai'i sparked a national controversy with its use of eminent domain to remedy Hawai'i's unusually high concentration of land ownership and limited housing stock by taking property from private landowners for the development of housing. In *Hawai'i Housing Authority v. Midkiff,* 467 U.S. 229 (1984), the U.S. Supreme Court affirmed Hawai'i's broad interpretation of the scope of "public" purposes that can justify eminent domain; since then, however, there has been much legal debate and several further U.S. Supreme Court decisions on the standard of "publicness" that an objective must meet to justify the use of eminent domain.

Of course, with the exception of the constitutional provisions and the federal authorities, all of these above-described laws, rules, and orders can be changed by enactment of the Hawaii legislature. Thus, most of these legal authorities need not stand in the way of the adoption of any of the models described below, if the Hawaii legislature and governor support such adoption.

Moreover, while the above overall framework offer a preliminary insight into the sources of law that affect our analysis, more research and analysis regarding each ownership model will be necessary as the details of the models are further refined. Such caveats have been noted in the appropriate sections for each ownership model. Task 1.3.2 will more thoroughly analyze the legal challenges for select models.

Finally, there are two incumbent utility types in Hawaii: the IOU (in the case of the subsidiaries of HECO Companies namely HECO, MECO, and HELCO), and the co-op (KIUC). While many of the topics and issues will be relevant to the acquisition of either type of utility, this analysis will note if there are any distinctions and considerations unique to each model where appropriate and necessary.

Figure 2. Framework for the Feasibility Criteria

Criteria	Categorization	Relevant Factors
Technical Feasibility	Implications for the utility role and responsibilities	Utility ownership and operation of generation, transmission, and distribution assets
		Utility is subject to PUC standards
	Assumption of utility short-term and long-term responsibilities	Access to human resources
		Infrastructure requirements
		Institutional requirements
		Business model compatibility
		Stakeholder engagement and oversight
		Potential for innovation
		Potential for competition and efficient markets
		Roles and incentive alignment
		Context-specific factors (i.e. transactions, regulations)
Financial Feasibility	Ratepayer impacts	Likely effects on rates
		Likely effects on public debt
		Rate and price volatility
		Customer-oriented value streams
	Financing options and factors	Willing buyer/seller
		Credit ratings
		Access to low-cost capital
		Context specific factors (i.e. transactions, regulations, management)
		Effects on competition
		Costs of associated infrastructure or institutions
Legal Feasibility	Existence of supporting legal frameworks	Preexisting legislative, PUC, local county frameworks
		Requirements for establishing new frameworks
	Governance requirements	Independence from appropriate interests
	Additional legal factors	Constraints on hiring
		Constraints on funding
		Other necessary regulatory reforms

4 New parent under IOU

Under the "new parent" model, the IOU ownership model of the HECO Companies would not change. However, another IOU would take ownership of the HECO Companies. There are several possibilities for such an arrangement:

- acquisition by another IOU or utility holding company;
- acquisition by a private equity or other private investor group;
- acquisition by a private entity and operating as a Benefit Corporation ("B-Corporation").[39]

In recent years, potential purchasers falling into each of the three categories above have been discussed in Hawaii. The potential acquisition that received the most attention, and which was formally evaluated in a docket before the Hawaii PUC was the proposed acquisition of the HECO Companies by NextEra Energy. While mergers and acquisitions activity has many drivers, some of the key motivations include potential cost savings, synergies between companies, diversification (e.g., in regulation, geography, and assets), and growth opportunities.

4.1 Technical feasibility

The following section evaluates the new parent ownership model (with the assumption that the new parent is another IOU-like entity) according to the standard of technical feasibility. It offers a high-level evaluation regarding the two questions outlined in Section 3.1., outlining the major key factors that impact outcomes.

- **Will this new ownership model change the roles and responsibilities of the utility? Would this require additional infrastructure or capabilities?**

No significant changes. There is no reason to believe that a shift in ownership would intrinsically change the roles and responsibilities of the utility, if all other factors, including regulation, are held constant. The utility would be required to ensure adequate and reliable electricity supply, provide high-quality customer service, and avoid interruption of service. Under this ownership model, the utility would also continue to have a central role in owning and operating the generation, transmission, and distribution assets.

- **Will the ownership model be able to comply with the reliability, adequacy, and quality of service standards established by the PUC over the short and long-term?**

Subject to prior experience and knowledge. With appropriate resources, and if the new owner for the HECO Companies is a preexisting IOU entity, the new owner would be able to comply with the reliability and performance and service quality requirements set by the PUC. This capability may come from a host of resources: prior experience, synergies between entities, in-house expertise,

[39] It is also possible that HEI could choose to attain B-Corporation certification without an external acquisition.

amongst others. Relative to the other ownership models, the new parent ownership model has the potential to supplement the operations of the utility with preexisting expertise.

That noted, the existence of such capabilities does not necessarily imply that they are deployed or managed effectively, or that the merger process retains in-house expertise.

The Benefit Corporation Model Overview

The B Corporation ("B Corp") Certification is a designation available to for-profit businesses that is administered by B Lab, a global nonprofit organization. The certification aims to redefine business achievement to include comprehensive stakeholder impact in addition to traditional financial metrics. Businesses that obtain a B Corp Certification meet high standards of verified social and environmental performance, public transparency, and legal accountability, and aspire to use markets to solve social and environmental problems. There are more than 2,100 Certified B Corps across 50 countries.

See Appendix B for further requirements and characteristics of B-Corps.

Subject to PUC enforcing similar conditions as it did for NextEra acquisition. A new IOU owner could hypothetically achieve the State's clean energy goals, but such an achievement would depend on the wherewithal of the new owner to achieve such goals. For example, some utility business models might not clearly support the focus on increasing diversity and competition in generation, distribution and other assets. In the case of the NextEra merger, some argued that a utility that relies primarily on the traditional vertically integrated monopoly is arguably a step backward from achieving the diversified energy landscape envisioned in the State energy goals.[40]

The impact of regulation. Moreover, the achievement of the state goals will depend on how the IOU is regulated by the PUC. If properly regulated, the profit motive of the IOU can be directed by the regulator towards the objectives most meaningful to the state.

Responsiveness to shareholders. Finally, one significant concern is whether a new IOU owner would reflect the needs and desires of the constituencies that it serves, or towards shareholders. This concern is more fully elucidated in the stakeholder feedback below.

[40] "Direct Testimony of Scott Hempling," Docket No. 2015-0022, Planning Office Exhibit – 4, Section III, available at: http://www.scotthemplinglaw.com/files/pdf/hempling-testimony-nextera-acquisition-Hawai'ian-electric-2015.pdf

Stakeholder Feedback: Comments on the New IOU Ownership Model

During the stakeholder outreach conducted as a part of this analysis, one frequent point of feedback related to the IOU model of utility ownership is a perceived misalignment between a utility's incentives (maximizing financial returns to utility owners and shareholders) and public policy goals and community priorities (such as reduced electricity rates, increased renewable electricity generation, etc.). Stakeholders note that this misalignment could be addressed in two ways – either through a transition to alternate forms of utility ownership or through regulatory reforms that align investor incentives with policy and community goals. As previously noted, regulatory pathways for accomplishing such a goal will be addressed in the subsequent analysis.

The broader conclusion for the "new owner" model is that it is possible that an IOU that would bid to be a new owner of HECO Companies could possess the necessary experience, expertise, and possibly financial resources, to fulfill the roles and responsibilities of an electric utility, although such an outcome is not assured. The technical feasibility largely depends on the specific capabilities of the new owner, its desire and wherewithal to meet State goals and standards, and broader regulatory changes and enforcement. For example, the PUC rejected the proposed NextEra merger in part because the plans of NextEra did not demonstrate a clear commitment and plan to action to meet the State clean energy goals. However, there is no intrinsic barrier that prevents or excludes future new owners from advancing a plan that can sufficiently meet the PUC guidelines.

4.2 Financial feasibility

As noted in Section 3.2, this analysis will outline: (1) potential impacts on ratepayers and (2) relevant factors determining whether the ownership model is financially able to acquire the incumbent utility and fulfill its responsibilities and roles as an electric utility.

- **What are the relevant factors to consider for determining whether the new model is financially capable of acquiring the incumbent utility?**

Like most other mergers and acquisitions processes, this ownership model would likely occur through the financing of some combination of debt and equity at market-based rates, subject to PUC approval and the public interest standards noted in Section 3.

Broad access to capital. One potential upside of a new IOU owner, by virtue of being investor-owned, is that it may have broad access to capital markets. However, this access to capital markets does not necessarily entail lower costs of capital, since the cost of capital can vary according to market conditions, the nature of the asset, and the characteristics of the acquiring entity. Nor is it necessarily guaranteed that broad access to capital is unique to an IOU owner.

Improvement in credit ratings. Another potential upside is that the merger or acquisition improves the finances of the HECO Companies, allowing it to borrow at a lower cost. Such improvements in credit ratings and access to capital also depend on the nature of the acquiring company. If

achieved, credit improvements could entail the procurement of improvements and infrastructure in a more cost-effective manner, since the cost of debt for such projects would be lower. However, this outcome is not guaranteed; the Project Team's analysis in Task 1.2.2 concluded that the credit rating of the acquired company, even when purchased by an acquiring company with a higher credit rating, have had mixed results in terms of improvement.

Overall, while there are many hypothetical benefits of a new IOU owner, these financial benefits are not intrinsic to the IOU model and rely on additional characteristics, including the nature of the proposed transaction, characteristics of the acquiring entity, PUC enforcement of its guidelines for ownership transitions, market conditions, among others.

- **What financial benefits or costs would be accrued to ratepayers or taxpayers?**

Rate moratorium, freezes, and credits. Often, in mergers and acquisitions of utilities, the new owner will offer – or be required by regulators to offer – action on freezing rates, a rate moratorium, providing credits, or all the above. In the case of the proposed NextEra merger, NextEra proposed offering $60 million in rate credits and four-year rate moratorium, amongst other measures. Such rate freezes, while they may secure initial support for the transaction, in some cases may only delay some costs that are inevitably reflected in future rates, blunting the positive effects on ratepayers.

The financial impact of unregulated businesses.[41] Another consideration is whether the new owner has other unregulated businesses, or might incur other obligations, that would eventually impact ratepayers. Financial obligations incurred by these non-regulated businesses could potentially be levied on Hawaii ratepayers, leading to increases in rates. The PUC has maintained that Hawaii ratepayers should not pay for the costs of business actions and services that are outside of regulatory control. In addition and as noted in Section 3, the PUC directs the new owner to provide ring fencing mechanisms to protect the HECO Companies' customers from the impacts of possible bankruptcy or other major problems that may happen in the future with other members of an applicant's corporate family. Therefore, the likelihood of this happening with the new owner is low.

4.3 Legal feasibility

The following section assesses the new owner model according to the questions outlined in Section 3.3. It assesses whether significant changes are necessary for the new ownership model, the governance structure for the intended operation of the new ownership model, and any additional legal considerations.

[41] "Unregulated businesses" refers to businesses that are not subject to rate regulation.

- **Is there an existing legal framework for this ownership model? Are any legal or regulatory changes necessary for this ownership model?**

There is a preexisting legal framework to support the new parent model. This preexisting legal framework is grounded in statutory law, which has been applied by the public utilities commission in its consideration of the transfer of KIUC and the proposed NextEra merger.[42] Specifically, barring exigent circumstances, all mergers and acquisitions activity is subject to the scrutiny of the PUC pursuant to HRS § 269-17, 17.5, 18, and 19, depending on the type of transaction at issue.

Unlike appellate courts, the PUC is not bound by the rule of *stare decisis*, so its decisions in past matters do not control its future decisionmaking. Nevertheless, the PUC often follows standards and legal tests it articulated in prior similar matters. In the proposed NextEra acquisition, the PUC followed a test it had earlier used to evaluate the KIUC transfer: "(1) whether the acquiring utility is fit, willing, and able to perform the service currently offered by the utility to be acquired, and (2) the acquisition is reasonable and in the public interest."[43] In its application of this test, the Commission expanded it into six issues, with a number of additional sub-issues, which addressed considerations like the following:[44]

- Will the transaction diminish the commission's regulatory authority over the HECO Companies?
- Will the financial size of the HECO Companies, relative to the other affiliates of the new owner, diminish regulatory control?
- Have the new owner or any other affiliate been subject to compliance or enforcement orders issued by any other regulatory agency or court?
- Are any conditions necessary to ensure that the proposed transaction is not detrimental to the interests of the of the ratepayers or the state and what conditions are necessary to avoid adverse consequences?

In addition, the PUC attached to its NextEra D&O a 17-page Appendix providing "guidance . . . on key elements that would be necessary to meet the public interest standard in any future applications seeking a change of control of the HECO Companies."[45] This guidance also will not legally control the decisions of the PUC regarding future public utility transfers, but it is highly

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[42] Hawaii Public Utilities Commission, Order No. 33795 (Dismissing Application Without Prejudice and Closing Docket) (referred to herein as the "NextEra D&O"), available at: https://puc.Hawai'i.gov/wp-content/uploads/2016/07/FINAL.ORDER_.33795.Docket2015-0022.pdf

[43] Nextera D&O at 34-35

[44] *Id.* at 30-31.

[45] Appendix A to Nextera D&O, at 1.

likely to be used as persuasive authority for any such transfer, especially if the transfer were to occur in the near term, while commissioners who participated in the NextEra decision remain on the PUC, and before political or technological developments change the PUC's preferences.

Key Considerations for Reasonableness, Public Interest, and Technical Requirements for the NextEra-HECO Companies Acquisition Proposal

1. Whether the transaction is reasonable and in the public interest:

- The interests of the State's economy and local communities served by HECO;
- The quantifiable benefits to the HECO Companies' ratepayers beyond those proposed by the HECO Companies in recent regulatory filings;
- The impacts on the ability of the HECO Companies' employees to provide safe, adequate, and reliable service at reasonable cost;
- The reasonableness of the proposed financing and corporate restructuring;
- The adequacy of safeguards to prevent cross-subsidization of any affiliates and to ensure the commission's ability to audit the books and records of the HECO Companies, including affiliate transactions;
- The adequacy of safeguards to protect the ratepayers from any business and financial risks associated with the operations of the new owner and/or any of its affiliates.
- The impact on the State's clean energy goals;
- The impact on competition in Hawaii's various energy markets and what regulatory safeguards are required to mitigate such adverse impacts.

2. Whether the new owner is fit, willing, and able to properly provide safe, adequate, reliable, electric service at the lowest reasonable cost in both the short and long-term:

- The affordability of electric rates for the customers of the HECO Companies;
- Improvement in service and reliability for the customers of the HECO Companies;
- Improvement of the HECO Companies' management and performance;
- Improvement of the financial soundness of the HECO Companies.

Source: Hawaii Public Utilities Commission, Order No. 33795, Docket No. 2015-0022, https://puc.hawaiiHawaii.gov/wp-content/uploads/2016/07/FINAL.ORDER_.33795.Docket2015-0022.pdf

- **What governance structures would be necessary for this new ownership model to function as intended?**

No significant changes to the governance structure. The general governance structure of the new owner would presumably remain the same in the case of a new IOU ownership body. The exception is in the case of a new IOU owner of KIUC, in which case the governance of the resulting entity would be guided more by equity and shareholder representation on the board, rather than through the election via local citizens and customers. Additionally, the PUC could use any order approving a transfer to a new owner to impose conditions that the new owner must follow, and these conditions could be used to require certain the new owner to adopt a certain form of corporate governance, or take other steps to implement state policy.

- **Are there any additional legal considerations for the viability of this new ownership model?**

Other than the legal considerations outlined above, any additional legal considerations will be included in Task 1.3.2, if this model is ranked for subsequent review.

4.4 Conclusion

In summary, much of the feasibility of the new ownership model is subject to the conditions and characteristics of the acquiring entity, and thus it ranks neutral in terms of the overall feasibility criteria. Some uncertain effects include potential improvements in the credit rating of the utility, or the access and costs of capital of the new owner.

Regarding assured characteristics, the new ownership model has the benefit of a pre-existing legal framework, requiring little in terms of crafting new regulations and legislation. Moreover, for some of these standards, the PUC has outlined key characteristics that the PUC would expect the transaction to meet to achieve the public interest standard. The corresponding disadvantage of the new ownership model is that it would not change Hawaii's existing regulatory or business models, and therefore may not be a significant improvement over the status quo. In particular, a new IOU owner would likely be subject to greater shareholder influence relative to the other ownership models considered throughout this document. This shareholder influence may conflict with the priorities of local stakeholders due to the general tendency of shareholders to seek profit maximization, which may challenge the utility's ability to meet other State energy goals, such as lower electricity rates.

Figure 3. New IOU Owner: Feasibility Criteria Summary

Criteria	Categorization	Various Considerations
Technical feasibility	Implications for the role and responsibilities of the utility	(+/-) No significant changes
	Assumption of utility responsibilities	(+) Access to in-house staff and expertise
	Achievement of State clean energy goals	(+/-) Subject to proposed transaction
		(+/-) Subject to regulation
		(-) Possibly incompatible business models
		(-) Subject to shareholder control, not local stakeholders
Financial feasibility	Impacts on ratepayers	(+) Rate moratoriums, freezes, or credits
		(+/-) Potential financial impact of unregulated businesses
		(-) For profit company with shareholder profit
	Cost factors for initial acquisition	(+/-) Subject to the proposed transaction
	Cost factors for achieving State clean energy goals	(+/-) Subject to the proposed transaction
		(+/-) Broad access to capital, but not necessarily an increase
		(+/-) Possible increase in credit rating of utility
Legal feasibility	Existence of supporting framework	(+) Preexisting legal framework, although past decisions do not necessarily establish precedent
	Governance requirements	(+) General IOU governance structure unchanged
		(+/-) Potentially subject to PUC determination
	Additional legal factors	(+/-) Subject to PUC approval

5 Hybrid with majority government ownership

In the hybrid model, the Hawaii state government would take majority ownership over the IOU, exerting influence through its voting rights on the board. Such a transition from an incumbent, wholly privately-owned IOU towards a majority government share is somewhat rare in the United States. Internationally, most of these cases have emerged from the partial privatization of state-owned assets. Outside of the electricity context, however, there are instances in which the U.S. government has taken full or partial ownership of a private company, sometimes due to financial distress and exigent circumstances that affect the public interest. One example is Amtrak. Railroads were the original public utility, which inspired the invention of public utilities regulation. Through the first half of the 20th century, they were generally owned by private corporations, and regulated by the Interstate Commerce Commission and state regulatory commissions, much as electric utilities are today. By 1970, however, increased competition from newer transportation technologies (such as highways and automobiles) had led to pervasive problems with passenger railway service, and the federal government responded by encouraging passenger railroads to merge their assets into the National Railroad Passenger Corporation, which does business under the "Amtrak" name. Amtrak is a private corporation, but the federal government owns all of its stock. Other examples of federally-controlled private corporations include the Overseas Private Investment Corporation, the Millennium Challenge Corporation, and "Fannie Mae."

In practice, the differences between these government-controlled private corporations and governmental agencies are sometimes more formal than substantive. For both government agencies and publicly-owned private corporations, governance can be set up in a way that provides various degrees of independence from the political branches of government, and it is not clear that one model is inherently more "independent" than another. Moreover, government-controlled corporations have exhibited a tendency to evolve into full-fledged government agencies. For example, in 2008 the U.S. Supreme Court held that Amtrak was a governmental entity for some purposes, in spite of its corporate form.[46] Similarly, over time Fannie Mae evolved from a private corporation to something more similar to a government agency. In 2010, as part of the fallout from the 2008 financial crisis, the federal government assumed more control over Fannie Mae, delisting the corporation's stock from the New York Stock Exchange.

For this scenario, we consider the possibility that the Hawaii state government takes majority ownership in the HECO Companies and/or KIUC, without converting the utilities into a state agency.

5.1 Technical feasibility

The following section evaluates the hybrid ownership model (assuming majority government share) according to the standard of technical feasibility. It offers a high-level evaluation regarding

[46] *Dep't of Transp. v. Ass'n of Am. Railroads*, 135 S. Ct. 1225, 1228, (2015).

the two questions enumerated in Section 3.1., outlining the major key factors that would impact outcomes.

- **Will this new ownership model change the roles and responsibilities of the incumbent utility? Would this require additional infrastructure or capabilities?**

No significant change. A shift towards government majority ownership would not intrinsically change the roles and responsibilities of the utility, if all other factors, including regulation, are held constant. The utility would continue to have a central role in owning and operating generation, transmission, and distribution assets. The utility would be required to ensure adequate and reliable electricity supply, provide high-quality customer service, and avoid interruption of service.

- **Will the ownership model be able to comply with the reliability, adequacy, and quality of service standards established by the PUC over the short-term and long-term?**

Negligible short-term impact, subject to government decision-making. There is no reason to believe that the hybrid model would be immediately incapable of undertaking the ongoing responsibilities of utilities in terms of providing reliable and adequate energy supply and rendering quality of service, as defined by the service standards of the PUC.

However, exceptions could occur if government majority ownership disrupted hiring, employment, or operations. Given the lack of precedent in the United States for this kind of action with IOUs, the potential effects of this ownership model are unclear. However, if the incumbent utility is not deficient in its responsibilities, it is likely that the utility will continue its day-to-day operations while undergoing more substantive transformations over the long term. This feasibility analysis assumes that government majority ownership does not significantly disrupt the core utility workforce and operations upon initial acquisition.

Over the long-term, the effectiveness of the hybrid ownership model in meeting the goals and standards of the PUC might be affected by some of the following factors:

*Potential conflict in public/private roles***.** The hybrid utility will face conflicting pressures and demands between its private role demanded by its shareholders and its public role by government ownership. For example, promoting a more diverse and competitive marketplace for energy may undercut the market share of the hybrid owned model and the equity interests of private shareholders. Other conflicts emerge if certain projects have public value and are supported by the government, but do not deliver private value to shareholders. These conflicts could entail that the hybrid model performs neither of its roles particularly effectively.

Inefficiency. From international experience, state-owned enterprises, or parastatals, have suffered from operational and/or financial inefficiencies. One explanation is the separation between government officials and accountability for ensuring that expenditures are cost-effective. This contrasts with equity ownership by private shareholders, who seek efficiency because it directly affects their retained earnings. The overall impact of such inefficiencies is a higher cost to achieve its state energy goals than would otherwise be necessary.

Potential to reduce investment from the private sector. The support that the hybrid entity may enjoy from the state could potentially reduce private investment, which could lead to a less diverse marketplace for energy services. That said, such support may also come with benefits that are further outlined in the section on financial feasibility.

Responsiveness to Stakeholders. By being majority owned by the government, local officials may have more direct influence over the operations and management of the utility, which may allow for greater alignment with the State goals. This may also ensure that there is a greater balance between technical, economic, environmental, and cultural considerations in utility operations. However, this also depends on the nature of the relationship, or the governance structure, between the government and the holding company managing the hybrid utility.

Ideally, the hybrid model allows for the possibility of the government having more direct control over the utility and ensuring alignment with State goals while taking advantage of the efficiencies generated by private ownership. It is possible that the hybrid entity would achieve the State energy goals, but it is unclear whether it would do so in the most cost-effective manner.[47]

5.2 Financial feasibility

As noted in Section 3.2, this analysis will outline (1) potential impacts on ratepayers and (2) relevant factors for whether the hybrid ownership model is financially able to acquire the incumbent utility and fulfill its responsibilities and roles as an electric utility.

- **What are the relevant factors to consider for determining whether the new model is financially capable of acquiring the incumbent utility?**

The Hawaii state government would most likely purchase the majority share of utilities through bond issuance. There are several factors that impact the feasibility of this pathway:

Strength of Hawaii's credit rating. While such a purchase may initially increase the overall debt of the State of Hawaii, the long-term impacts are uncertain. In terms of initial feasibility, it should be noted that Hawaii has an optimal credit rating, with a credit score AA1 from Moody's, AA+

[47] Hypothetically, the hybrid model could also serve as a transitory model to another government-owned model, such as the municipal model. The full scope of this process is outside of this report, but is acknowledged as a long-term option.

from S&P Global, and an AA rating from Fitch as of May 2017.[48] This implies that there is room for the Hawaii government to undertake debt at a reasonable cost.

Limits on bond issuance. Hawaii's total principal amount of outstanding indebtedness was approximately $10.5 billion by July 1, 2016.[49] While the government can issue bonds to help finance such a purchase, such bond issuance can be limited by economic considerations (such as impacting the creditworthiness of the government) or by legal considerations (such as limits imposed by the Hawaii constitution). It is worth noting that a $1.9 billion transaction would be substantial relative to the Hawaii state budget. For reference, the annual allocated budget for the fiscal year 2016-2017 was $13.7 billion.[50]

Various acquisition options. There are a variety of routes by which the government could make a majority purchase in the hybrid entity. The first could entail a negotiated purchase, which would likely require board approval by the HECO Companies. Another route is through a tender process of purchasing shares, which would resemble more of a "hostile" takeover, and risks defensive actions on behalf of HEI to deter against such a proposition, including raising the share price. A "hostile" acquisition would potentially raise the overall acquisition cost, but it is unclear how much this cost would rise.

Financing "halo" effect. Following the initial acquisition, the partial ownership of the state can potentially lower the cost of capital. This relies on a financing "halo" effect, in which investors assume that there is implicit backing, or sharing of risks, by the host government. In this case, this has the effect of lowering the overall cost of capital, allowing the utility to incur debts at a lower cost. However, if risks are indeed shared by the government majority owner, then the lower cost also comes at the price of increased risk exposure for local citizens.

Overall, the hybrid model involves a significant up-front investment to acquire the majority share of the company. However, it may potentially allow for a longer-term lower cost of capital if investors view the government as absorbing some of the risks of the business. However, financial feasibility is subject to the transaction, limits on bond issuance, and government management.

- **What benefits or costs would be accrued to ratepayers or taxpayers?**

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[48] The Pew Charitable Trusts, "Rainy Day Funds and State Credit Ratings," May 2017, available at: http://www.pewtrusts.org/~/media/assets/2017/05/statesfiscalhealth_creditratingsreport.pdf.

[49] "Outstanding Total Indebtedness of Hawaii as of July 1, 2016," The State of Hawaii, available at: https://budget.hawaiiHawai'ihawaii.gov/wp-content/uploads/2012/11/2016-Indebtedness-Stmt-conformed-sig-11-23-16.pdf

[50] Hawaii Department of Budget and Finance, "Summary of Expenditure Variances," December 2016, available at: fhttps://budget.hawaiiHawai'ihawaii.gov/wp-content/uploads/2016/12/04-Summary-of-Expenditure-Variances-FY16-FY17-VR.pd.

Up-front cost. For the impacts on ratepayers, any expenditure by the state government to purchase the company could be internalized through an increased burden on taxpayers. To illustrate the order of magnitude, such a purchase could entail a minimum expenditure of $1.9 billion dollars to acquire a 51% stake in HEI at its October 2017 stock price.[51] A more thorough financial analysis should evaluate both the direct costs in terms of rate impacts as well as indirect costs from debt incurred by the Hawaii state government, which is not part of the scope of work for this task.

Ongoing costs. Much depends on the management and subsequent efficiency of the hybrid-owned enterprise. If the hybrid model is managed and operated in a manner that is economically inefficient (for example, investing in projects that create political goodwill but are not merited from an economic or business perspective) then it is likely that costs will be higher than necessary, eventually necessitating that they be recouped either from ratepayers in the form of rate increases or from taxpayers in the form of subsidies. If the enterprise is run in an efficient manner, it could serve as an additional revenue stream to the government or help to lower rates in Hawaii.

However, there are potential financial benefits to taxpayers, particularly if the cost of financing of projects is reduced, and if the public-private relationship can allocate risks prudently amongst the parties.

5.3 Legal feasibility

The following section assesses the hybrid ownership model according to the standards outlined in Section 3.3. It assesses whether significant changes are necessary for the hybrid ownership model, the governance structure for the operation of the hybrid ownership model, and any additional legal considerations.

- **Is there a legal framework for this ownership model? Are any legal or regulatory changes necessary for this ownership model?**

Requires legislative action. If Hawaii were to undertake this route, the legislature would likely need to charter a holding company through which the Hawaii state government could purchase the shares of HEI and exercise control over the board. This would likely require legislative action for outlining its authorities, responsibilities, relationship to other entities and other stipulations, in addition to appropriating the funding necessary for establishing and operating the holding company. It would also be necessary to evaluate how funding for such an entity would be financed, including bond issuance.[52] Following the establishment of the holding company, the Hawaii state government would have to appoint all necessary board members, including those who would take board membership at the HECO Companies.

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[51] This is approximately 51% of the shares outstanding at the October 17, 2017 share price of $34.89.

[52] For further details, see the Hawaii State Constitution on special purpose revenue bonds, which can be utilized for the financing of public utilities, which can be authorized through a two-thirds vote in the legislature. The Constitution of Hawaii, Article VII: Taxation and Finance, Section 10, Subsection 12, Available at: http://lrbhawaiihawaiiHawai'i.org/con/conart7.html.

It would also be necessary to consider if the conditions of which such a government purchase of shares in a private corporation is authorized by the Hawaii constitution, and under which conditions this takeover is authorized. We have not identified any constitutional provisions that prohibit such an action, but we are also not aware of any examples of government-controlled private corporations in Hawaii, so this issue would merit further careful research and analysis.

- **What governance structures would be necessary for this new ownership model to function as intended?**

Delineating private and public governance. Additional key factors concern the general governance of the state-owned enterprise, for example using an independent board of directors. Some significant questions include the "degrees of separation" from political interference by the State. There is a tradeoff between ensuring the independence of the utility (and thus shielding it from political interference), and the capacity to use the enterprise as a tool to advance policy goals.

- **Are there any additional legal considerations for the viability of this new ownership model?**

Additional considerations. Some additional legal considerations include the hiring and management of employees at the state-owned entity and the degree to which such employees are considered employees of the state. Finally, appropriate regulations may be necessary to preserve a competitive marketplace and restrain the use of government backing to reduce market diversity in energy services.

5.4 Conclusion

In conclusion, the hybrid ownership model establishes a holding company, as well as allocating several billion dollars to purchase a majority share of the utility, for the promise of increased governmental control, the possibility a lower cost of capital, and potential synergies between the integration of public and private actors. The general promise of public-private partnerships such as the hybrid model is that they can leverage the strengths of both entities (the government and the private sector) to facilitate ambitious projects while ensuring that risks are allocated to those most capable of managing them. However, the challenge of the hybrid ownership model is the potential conflicts in roles that such an entity may experience, misaligned incentives, and potential to reduce private sector investment.

Figure 4. Hybrid with Government Majority: Feasibility Criteria Summary

Criteria	Categorization	Various Considerations
Technical feasibility	Implications for the role and responsibilities of the utility	(+/-) No significant changes
	Assumption of utility responsibilities	(+/-) No significant changes
	Achievement of State clean energy goals	(+/-) Subject to short-term decision-making
		(+) Increased local control
		(-) Misalignment of incentives and risk allocation
		(-) Perception of inefficient and poor management
Financial feasibility	Impacts on ratepayers	(+/-) Subject to local priorities
		(+/-) Subject to government management
		(-) Increased public debt
	Cost factors for initial acquisition	(+/-) Subject to the "friendliness" of transaction
		(+) Strong Hawaii credit rating
		(-) Potential limits on bond issuance
	Cost factors for achieving State clean energy goals	(+) Financing "halo" effect
Legal feasibility	Existence of supporting framework	(-) Requires legislative chartering of a holding corporation
		(-) Requires substantial legislative bond issuance
		(+/-) Unclear legal outlook
	Governance requirements	(+/-) Subject to determination of public/private role
		(+/-) Subject to independence of holding company
	Additional legal factors	(+/-) Subject to determination of civil service status for employees

6 Municipal utility ("munis")

Under the municipal utility ("muni") model, local governments would take ownership over the utility assets within their respective jurisdictions. Munis have a long history and tradition in the United States, with over 2,000 public electric utilities providing electricity to 49 million people in the country.[53] Municipalization has many motivations, including increasing local control over utility services, anticipated benefits in rate reductions, greater alignment with local goals, and fiscal returns to the local communities. Since 2000, 22 U.S. municipalities have attempted to municipalize their incumbent utility; two have succeeded. For the purposes of this analysis, we consider a scenario in which each of the island counties that are currently served by the HECO Companies takes ownership of the HECO Companies' assets and offer electricity service via a municipal department or independent board, similar to the municipal entities that currently provide water, sewer, and garbage, and other services in Hawaii.

Case Study: The City of Boulder

The City of Boulder ("City") has ambitious clean energy targets and considers municipal control over its distribution grid important to meeting these goals. In 2011 upon the expiration of the city's franchise agreement with its utility, Xcel, Boulder citizens voted in support of a forgoing a new franchise agreement and instead purchasing the utility's distribution grid infrastructure. The forced municipalization process is ongoing, now involves federal and state legal proceedings, and has cost the City $12 million over the past six years.

The City of Boulder initiated an eminent domain action to take ownership of Xcel energy electricity infrastructure needed to serve Boulder customers, including certain infrastructure located outside of city limits. However, the court held that

> [t]he PUC has the authority to regulate public utilities and the facilities, which provide service within the City of Boulder as well as unincorporated Boulder. The City has the right to create a municipal utility to serve its citizens. These facilities are intimately intertwined. Therefore, it is necessary and appropriate for the PUC to determine how facilities should be assigned, divided, or jointly used to protect the system's effectiveness, reliability, and safety. Such a determination must be made prior to the City's condemnation of property for utility municipalization.

In response to the court's decision, in September 2017 the Colorado public utilities commission issued a decision setting out a procedure for the steps that the City would need to undertake to succeed in its municipalization effort. The commission largely sided with Xcel on topics such as ruling against the joint use of distribution poles and substations, although Boulder retains the right to build new substations. Moreover, the regulator conditionally approved a list of distribution assets for Boulder to acquire, but only if Xcel secures sufficient property rights and permanent easements to locate, operate, and maintain its electric facilities in Boulder.

[53] American Public Power Association, "Stats and Facts," available at: https://www.publicpower.org/public-power/stats-and-facts.

Finally, the regulator ruled that the city is responsible for paying for any work Xcel must do to maintain service to its customers outside city limits because of separation efforts.

Sources: "Colorado regulators give Boulder much less than it wanted for municipalization," S&P Global Market Intelligence, September 15, 2017; Colorado Public Utilities Commission Decision No. C17-0750 in Proceeding No. 15A-0589E, issued September 14, 2017.

Another possibility would be for the state, rather than the counties, to take ownership of the HECO Companies' assets and offer service via a state agency. While it is less common in the U.S. for state agencies to offer utility service, the case of the Long Island Power Authority ("LIPA") (see Box 6) illustrates an instance of a government takeover of utility undergoing financial challenges. Additionally, as noted above, Hawaii's state government administers certain functions administered by local governments in other areas, such as public schooling. For convenience, the discussion below focuses on municipal utilities rather than state utilities, but most of the analysis also applies to the possibility of state ownership, with the exception of certain legal considerations specific to municipal ownership.

Case Study: The Long Island Power Authority

In the late 1990s, the assets of the struggling privately-held Long Island Lighting Company were acquired by the LIPA, a public entity created specifically for this mission. The acquisition occurred after nearly three decades of controversy over a debt from an abandoned nuclear power plant at Shoreham, a property tax refund that threatened to bankrupt communities, and soaring electricity bills. The acquisition itself was also contentious, with some arguing that it would burden future taxpayers with increased debt and future rate increases.

While assets are state-owned, LIPA has subsequently contracted out much of the utility's operations to private companies. In 2012, LIPA was widely criticized for a slow and inadequate response to Hurricane Sandy. As a result, its control over day-to-day management, previously managed by a third-party utility, has been handed over to another private sector operator, PSEG Long Island. PSEG has made significant investments to prepare the Long Island grid for future storms. Over the past three years, the utility has brought on extra linemen during storm season, invested in fortifying substations to prepare for floods, upgraded aging circuits, and encouraged customers to install behind-the-meter solar systems.

6.1 Technical feasibility

The following section evaluates the muni ownership model according to the standard of technical feasibility. It offers a high-level evaluation regarding the two questions outlined in Section 3.1., outlining the major key factors that would impact outcomes.

- **Will this new ownership model change the roles and responsibilities of the utility? Would this require additional infrastructure or capabilities?**

No significant changes. There is no reason to believe that a shift towards muni ownership would intrinsically change the roles and responsibilities of the utility, if all other factors including regulation and local government goals are held constant. The utility would continue to have a central role in owning and operating generation, transmission, and distribution assets. However, it is possible that the local government would have its agenda regarding the role of the utility, which could impact its responsibilities.

- **Will the ownership model be able to comply with the reliability, adequacy, and quality of service standards established by the PUC over the short-term and long-term?**

Hiring and retaining expertise. Over both the short and long term, one of the most immediate impacts of muni ownership is the potentially disruptive impact on human resources. The ability of a utility to meet reliability, adequacy, and quality of service standards ultimately rely on the expertise of professionals with a technical understanding and knowledge of electricity systems. If the workforce is integrated into civil service roles, this might have implications on whether key individuals remain with the muni utility, particularly if certain employment conditions from the incumbent IOU cannot be grandfathered. Hiring needs will also face challenges if civil service restrictions, and potentially lower salaries, disincentivize those with technical expertise from employment at the municipal utility.

However, the county governments in Hawaii are an attractive employer for many job candidates, and further research is required to determine whether civil service pay scales and employment constraints differ materially between the county governments and the HECO Companies. Moreover, to the extent that employment issues prove problematic, municipal utility employees can be exempted from civil service protections. For example, California's Municipal Utility District Act exempts certain positions at municipal utilities such as SMUD from civil service rules, and some other municipal utilities exempt certain roles, such as management positions, from civil service requirements.[54]

Short-term human resources interruptions can be addressed if there is an appropriate transition between the ownership entities of relevant employees and expertise. Presumably, there would be a detailed and thorough transition plan as part of the system purchase agreement, but such transitions can be subject to negotiation and challenge.

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[54] For example, the senior management of the Knoxville Utilities Board in Tennessee, and managers of the Jacksonville Energy Authority in Florida, which both operate as independent city agencies, are exempt from civil service requirements. See Baer, Walter S., Edmund D. Edelman, James W. Ingram III, and Sergej Mahnovski, Governance in a Changing Market: The Los Angeles Department of Water and Power. Santa Monica, CA: RAND Corporation, 2001. https://www.rand.org/pubs/monograph_reports/MR1189.html.

Integration with local government. By being part of the county government, munis may have access to additional resources in city services and regulation, albeit those resources might not necessarily be related to electricity grid management. Nonetheless, interoperability and integration with other city and county functions, particularly those in zoning, infrastructure, and other areas, may help to reduce some of the costs of the utility by expediting procedures and sharing costs.

Innovation. In the United States, munis tend to be unregulated by state commissions, although state legislation can otherwise require munis to adhere to State energy goals and targets, such as a Renewable Portfolio Standard.[55] Consistent with this approach, HRS § 269-31 explicitly establishes that the PUC's regulation under Chapter 269 "shall not apply to . . . public utilities owned and operated by the State, or any county, or other political subdivision." Assuming the muni is unregulated by the PUC, hypothetically it may have more flexibility to take innovative risks in the provision of energy services if the political will and resources exist to do so. That said, while some munis are innovative (some examples include the Sacramento Municipal Utility District, the Los Angeles Department of Water and Power, and the New York Power Authority), others are more conservative, even absent PUC regulation.

Responsiveness to stakeholders. Over the long-term, a municipal utility has unique attributes that assist with achieving the state goals, particularly given its integration with local government. It also allows for closer alignment with State energy goals, given that it is housed within the government. This allows stakeholders to exert greater political ownership over the activities of the muni.

Finally, some of the challenges associated with the hybrid ownership model, namely *efficiency* and a *reduction of private-sector investment*, might also impact the muni model. Regarding efficiency concerns, stakeholders were particularly vocal. These fears, however, are not necessarily substantiated by the nationwide evidence: as noted above, on a nationwide level, municipal utilities have consistently delivered lower rates than IOUs and restructured electricity systems, suggesting that they have the potential be more efficient than the alternatives.[56] It is also possible that the muni model may reduce private sector investment in electricity assets if, as a state-owned entity, it enjoys financial support unavailable to private sector competitors.

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[55] For example, California requires the governing boards of local publicly owned utilities to adopt programs for enforcing California's Renewable Portfolio Standard. While the California Public Utilities Commission does not regulate munis, the California Energy Commission may issue an administrative complaint if a muni fails to comply with these requirements. These complaints may be referred to California Air Resources Board, which may impose penalties. Other states, such as Colorado, have required munis serving more than a certain number of customers to adhere to a schedule for transitioning their energy supply to renewable energy.

[56] A municipal utility industry association offers data on this issue, based on EIA data from 1986-2010: http://www.publicpower.org/files/Media/PP%20Business%20Model-Tarbert.pdf. Similarly, a 2010 study of municipalization conducted by the Massachusetts Department of Resources at the request of the legislature found that municipal utility rates in Massachusetts were lower than IOU rates. MASSACHUSETTS DEPARTMENT OF ENERGY RESOURCES, MUNICIPAL UTILITY STUDY TECHNICAL REPORT 33-47 (January 28, 2010), http://www.mass.gov/eea/docs/doer/publications/doer-municipal-utility-rpt.pdf. A 2007 Connecticut office of legislative research study reached the same conclusion. KEVIN E. MCCARTHY, MUNICIPAL VS. INVESTOR OWNED UTILITY ELECTRIC RATES (January 2, 2007), https://www.cga.ct.gov/2007/rpt/2007-R-0014.htm.

In conclusion, the possibility that the muni model can meet PUC standards (or, absent PUC regulation, the general roles, and responsibilities of any electric utility) is not outside the realm of possibility, particularly if an appropriate transition plan is in place that transfers employees from the incumbent utility to the muni, and the organization can attract the technical expertise necessary for managing electricity systems. The long-term technical effectiveness of the muni option assumes that the local governing body will remain effectively dedicated to the long-term State energy goals, can capably manage a utility to innovate and meet the State goals, and can resolve any long-term human resource challenges. Finally, establishing independent boards for municipal utilities can potentially support their development and management, as it removes some of the political influence that can reduce economic efficiency in the management of municipal utilities.

6.2 Financial feasibility

As noted in Section 3.2, this analysis will outline (1) potential impacts on ratepayers and (2) relevant factors for whether the municipal government is financially able to acquire the incumbent utility and fulfill the responsibilities and roles of an electric utility.

- **What are the relevant factors to consider for determining whether the new model is financially capable of acquiring the incumbent utility?**

Tax-exempt debt. Munis have access to tax-exempt capital for improvements following the initial acquisition, which remains taxed. This can help ensure the cost-effectiveness of improvements made to achieve Hawaii's clean energy vision. However, there are limits on a town's bonding authority, subject to the credit of the municipalities in question, the cost of servicing such debt, and other legal limits of bond issuance.

County credit ratings. If the county governments seek to municipalize, most have positive credit ratings, either as Aa1 or Aa2, for their general obligation bonds.[57] This means that county credit ratings could potentially support an acquisition. However, the county governments will have to consider whether they would be willing to make the long-term financial commitment to buy the county operations and infrastructure of their utility.

Transactional viability. As noted in the introduction, whether there is a willing seller and willing buyer plays a large role in the completion and the cost of acquisition. If HECO is not looking for a buyer, particularly a municipal buyer, the municipal governments will have spent significant time, money, and energy simply exploring the option of municipalization before discovering the actual acquisition cost of assets in a legal proceeding.

In summary, the initial acquisition cost of municipal acquisition is the financial variable most subject to speculation. This acquisition cost will depend on the nature of the assets, the nature of

[57] Moody's. Ratings of GO Bonds for Hawai'i (Aa2), Kauai (Aa2), Maui (Aa1), Honolulu (Aa1).

the acquisition, and any negotiations or proceedings that would accompany the purchase. This would have long-term effects on ratepayers that will bear the costs of acquisition. However, following the acquisition, the muni model can access tax-exempt capital for infrastructure improvements, which would lower its cost of capital, presuming that the Hawaii municipal governments maintain a strong credit rating, and with all other factors held constant.

- **What financial benefits or costs would be accrued to ratepayers or taxpayers?**

Generally, all the factors that affect technical feasibility will also impact the benefits or costs accrued to ratepayers. Challenges in maintaining an expert workforce will be reflected in inefficiencies and potentially service disruptions that would raise the overall costs for ratepayers. *The uncertainty of legal challenges.* One of the most crucial factors in determining the financial feasibility of the muni model is the hostile or friendly nature of the transaction. If the transaction is hostile, then the initial cost of acquisition may be subject to court proceedings, tacking on additional legal fees and delays that undermine the effectiveness of the muni model. However, a friendly acquisition does not necessarily imply a cheap acquisition, since the local municipality could also hypothetically overpay for utility assets.

The economic impact of transitioning to a muni model depends on the wide variation in costs that could be incurred as part of an acquisition process. Much hinges on whether there is a willing seller.

Local stakeholder priorities. As an organ of government, munis are less beholden to the concerns of external shareholders, or the concerns of profit-making, and more beholden to the interests of voters. It could be that muni prioritizes lower rates, but it is by no means assured. For example, the muni could prioritize the procurement of clean energy to the detriment of lower rates. Alternatively, it could focus exclusively on lower rates, undermining its financial capability to implement other stakeholder priorities. This could be addressed through a clear charter for the muni as well as the implementation of an independent board of directors.

6.3 Legal feasibility

The following section assesses the muni ownership model according to the standards outlined in Section 3.3. It assesses whether significant changes are necessary for the muni ownership model, the governance structure for the operation of the muni ownership model, and any additional legal considerations.

- **Is there a legal framework for this ownership model? Are any legal or regulatory changes necessary for this ownership model?**

Municipal government power to offer electricity service. There is likely no legal barrier that would prevent a county from passing an ordinance that would set up a legal "shell" for a new muni. As noted above, Hawaii's counties have "home rule" powers that generally allow them to adopt ordinances as long as the ordinances are not inconsistent with state law, so they likely have the power to offer electricity service. HRS § 269-31 explicitly exempts municipalities from the scope of HRS Chapter 269, so state public utilities law likely does not prevent such a step. Finally, the

HECO Companies' franchises are explicitly non-exclusive, meaning that they do not foreclose the existence of a new muni, either.

"Friendly" transfer of utility assets to municipal/state government. However, the ***transfer*** of existing utility assets from Hawaii's existing utilities to a new municipal utility raises a number of questions. Even if such a transfer is "friendly" (i.e. agreed to by the incumbent utility), it would raise legal questions about the intersection of Hawaii local government law and public utilities law. In particular, HRS § 269-19 may require the PUC's consent to the transfer of assets from the IOU to the new muni, unless the state legislature were to enact a law exempting the transaction from PUC review.

"Unfriendly" transfer of utility assets to municipal/state government. If the legacy IOU were not agreeable to the transfer of its assets to a new municipal utility, the municipal and/or state government has two potential levers that could be used to effect an "unfriendly" transfer," both of which raise legal questions.

First, most municipalization efforts have taken place at the expiration of a utility franchise agreement. The franchise agreements that govern the utilities in Hawaii are indefinite, but can be revoked at will by the Hawaii legislature. Additionally, the franchises state that if the utilities fail to comply with the laws of the State or the terms of the agreement, that the Public Utilities Commission, with the consent of the State governor and the attorney general, can render the franchise agreement null and void.[58] Accordingly, if the state government is in favor of forcing the transfer of assets from an IOU to a new muni, they might be able to do so by threatening the revocation of the HECO Companies' franchises – though that step alone would not necessarily be enough to secure utility cooperation, since the state government would not want to leave customers without electricity service.

Second, a county or the state could use the power of eminent domain to attempt to force a sale of the HECO Companies' real property and related assets to a new muni. This was the technique that the City of Boulder employed to attempt to obtain the assets necessary for its proposed muni. In that instance, the court held that the Colorado public utilities commission had jurisdiction over questions related to the transfer of assets, and stayed the eminent domain proceeding until the public utilities commission could issue a decision on those issues. A similar eminent domain effort would raise similar questions under Hawaii law.[59] For example, state eminent domain law

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[58] The franchise agreements are available in the Applicants' Response to LOR-IR-38, Docket No. 2015-022, or the regulatory proceeding for the NextEra merger.

[59] The Boulder situation was more complicated than an analogous Hawai'i effort might be, because the utility whose assets the City of Boulder sought to condemn (Xcel Energy) serves customers both inside and outside Boulder city limits. As a result, some of the assets needed to serve Boulder customers were located beyond city limits, and the transfer of the assets would have an economic effect on customers outside Boulder. This would be less of a problem in a Hawai'i eminent domain proceeding, since utility grids are generally county-specific, though the HECO Companies do share some administrative functions among HECO, MECO, and HELCO. Additionally, the Colorado public utilities commission enjoys *constitutional* jurisdiction over utilities, whereas the Hawaii PUC's jurisdiction is only *legislative*, which affects both the analysis of the jurisdictional split between county and state as well as the options on the table for clearing the path to municipalization using legislation.

gives the counties the power to condemn property, but state public utilities law gives the PUC jurisdiction over the transfer of all utility assets. Accordingly, does the PUC's jurisdiction preempt the county's eminent domain power, or does the eminent domain power preempt the PUC's jurisdiction? If a court holds that the exercise of the eminent domain power is subject to PUC jurisdiction, a PUC proceeding would likely be required to approve the transfer, in addition to a court proceeding on the valuation of the assets for the purposes of eminent domain.

Given these legal questions about the relative powers of the counties and PUC, as well as the practical uncertainties related to the fact that to our knowledge eminent domain has not previously been used in Hawaii to condemn utility assets on a large scale, it may be convenient for the state to enact a statute to clarify the process for "hostile municipalization" of public utilities in Hawaii. Such a statute could establish the relative roles of each agency and level of government in the process.

- **What governance structures would be necessary for this new ownership model to function as intended?**

Various governance structures. Those counties and/or cities that choose to municipalize will also be tasked with establishing a governing structure for this entity that can preserve its ability to function without political interference, while also still being subject to the authority of the local government. There are significant variations in the governance of munis, ranging from being formed as a department of the municipal government, to being run as an independent board or "authority" at greater arm's length from the municipal government. An independent board of directors is often established to ensure that the municipal utility receives pragmatic, non-political advice about major strategic and business decisions. In some cases, members of the board of directors are elected by the customers of the muni, creating a sort of hybrid between the muni and co-op models. This technique, for example, is used by the Sacramento Municipal Utility District ("SMUD"), a California muni that serves over 600,000 customers (covering a total population of 1.4 Million).

Article 8.2 of the Hawaii constitution allows a county to pass an ordinance adopting any of these governance approaches for its new muni, as long as the ordinance is consistent with state laws of general application. If a change to or wavier of any such state laws (such as civil service laws) is required, that would need to be accomplished by state legislative enactment.

- **Are there any additional legal considerations for the viability of this new ownership model?**

PUC regulation. As described above, HRS § 269-31 generally exempts munis in Hawaii from state public utilities regulation. If the PUC wants to regulate the muni, then new law would need to be enacted to subject the muni to PUC oversight. In general, however, such regulation is often thought to be unnecessary, since the muni will be directly subject to control by the public through its governance structures, rather than indirectly subject to control through PUC regulation.

6.4 Conclusion

In general, the muni model potentially may be more responsive to the needs and concerns of local stakeholders and offers the prospect of tax-exempt financing for subsequent infrastructure improvements. It is also possible that the muni could undertake more innovative actions, due its superior incentives to act in the public interest and its ability to act without first obtaining PUC approval. If the transition is "friendly," it could be accomplished with only PUC approval, as for the new IOU owner model. Even if it is unfriendly, the transition could be streamlined if it is supported by state policy, such as a state legislative enactment clarifying and streamlining the procedures for municipalization. By contrast, if the transition is both unfriendly and unsupported at the state level, it will raise contentious legal questions that may require litigation to resolve, as the Boulder effort has. Such an unfriendly, unsupported effort would have uncertain implications for acquisition costs and hence the overall impact of cost reductions for ratepayers. Another potential downside of the muni model is that it also may potentially disrupt the hiring and maintenance of a workforce with technical expertise, if the county governments are deemed a less attractive place to work than the HECO Companies, and if the muni is not exempted from any civil service requirements that prove problematic.

Figure 5. Municipalities: Feasibility Criteria Summary

Criteria	Categorization	Various Considerations
Technical feasibility	Implications for the role and responsibilities of the utility	(+/-) No significant changes
	Assumption of utility responsibilities	(+) Attractiveness of munis as employers
		(+) Integration with local government
		(-) Possible disruption of workforce, but solutions possible
	Achievement of State clean energy goals	(+/-) Subject to implementation and context
		(+) Potential innovation due to lack of PUC regulation
		(+) Increased responsiveness to local stakeholders
		(-) Perception of inefficient and poor management
Financial feasibility	Impacts on ratepayers	(+/-) Subject to the "friendliness" of transaction
		(+/-) Subject to local priorities
		(-) Increased public debt
	Cost factors for initial acquisition	(+/-) Subject to the "friendliness" of transaction
		(+) Strong county credit ratings
		(-) Potential limits on bond issuance
	Cost factors for achieving State clean energy goals	(+) Tax-exempt financing
Legal feasibility	Existence of supporting framework	(+/-) Variety of legal acquisition pathways
		(-) Requires county or referendum vote
	Governance requirements	(+/-) Subject to context and goals
	Additional legal factors	(+/-) The status or relevance of PUC oversight

7 Cooperative (Co-ops)

In the co-op model, Hawaii ratepayers within a certain geographical area of coverage would form a nonprofit that would take ownership of the utility assets of HECO Companies. Co-ops are common in the United States, with more than 900 electric co-ops that serve an estimated 42

million people,[60] although a co-op acquiring IOU assets is uncommon. Cooperative utilities tend to be smaller in size than IOUs but cover larger geographic areas: co-ops account for only 10% of electricity sales but serve roughly 70% of the US by land area. Some of the driving motivations behind the co-op model include greater customer (co-op member) control over the utility and the lack of a profit motive, instead focusing on the priorities of its customers-members. For that reason, co-ops have been particularly prevalent in rural areas, in part because these areas were unattractive to investor-owned utilities during the initial expansion of electric utility infrastructure across the country.

Case Study: Kauai Island Utility Cooperative

Hawaii's only co-op was formed in 1999, when the incumbent IOU, Citizens Utilities Company, announced that it wished to divest from the electric utility business. KIUC is governed by a nine-member Board of Directors. In 2017, KIUC's generation fuel mix is 56% fossil fuels, 9% hydro, 12% biomass, and 23% solar. The utility has multiple utility-scale renewable energy generation facilities, including solar, hydro, and biomass.

KIUC has been able to reduce its average bills by 26% over the last three years (while maintaining a high percentage of reliable service), which it attributes to low oil prices and a focus on cost control. However, Kauai still has the highest electricity prices amongst the utilities in the state. KIUC also states that the rising penetration of renewables on their grid has served to hedge against any rising costs in oil prices. As for its future steps, KIUC has requested to further move from the regulation of the PUC to a deregulated or minimally regulated status, which may potentially have implications via precedent for other cooperatives in Hawaii.

Source: KIUC, Strategic Plan Update, 2016-2030, January 31, 2017, available at http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/2016-2030_KIUCStrategicPlan-FINAL.pdf

7.1 Technical feasibility

The following section evaluates the cooperative ownership model according to the standard of technical feasibility. It offers a high-level evaluation regarding the two questions outlined in Section 3.1., outlining the major key factors that would impact outcomes.

- **Will this new ownership model change the roles and responsibilities of the utility? Would this require additional infrastructure or capabilities?**

No significant changes. A shift towards co-op ownership would not intrinsically change the roles and responsibilities of the utility, assuming that all other factors including regulation are held constant. The utility would continue to have a central role in owning and operating generation,

[60] National Rural Electric Cooperative Association, "America's Electric Cooperatives: 2017 Fact Sheet," January 31, 2017, available at: https://www.electric.coop/electric-cooperative-fact-sheet/

transmission, and distribution assets. However, it is possible that the co-op would have its particular agenda regarding the role of the utility, which could impact its responsibilities.

- **Will the ownership model be able to comply with the reliability, adequacy, and quality of service standards established by the PUC?**

Hiring and retaining expertise. Like the municipal model, one concern about the co-op model is adequate staffing of the co-op with a workforce of relevant experts and technical specialists, particularly if the co-op is unable to pay the salaries to match the incumbent IOU. In part, such a disruption in hiring and training can result from a poorly managed transition and shifting stakeholder interests that undermine the ability of the resulting co-op to sustain operations at a similar level of the incumbent IOU.

Nevertheless, a co-op can rely on its co-op networks for education and training. The National Rural Electric Cooperative Association ("NRECA") provides training and resources to help the co-op's elected leaders as well as employees during transition and operation of the utility. These training include certificate courses, tailor-made materials for co-ops that can be used locally, and online resources. Courses are offered for employees in every area of the operations of utility, for boards of directors and co-op attorneys. When KIUC transitioned to a co-op, its board of directors committed to obtaining a certificate of competency from NRECA. The certificate of competency is awarded once a prescribed number of courses are taken.

For such a transition to be successful in Hawaii, much of the HECO Companies' staff would presumably need to be retained and employed by the new entity. This was the case in Kauai when KIUC hired many of the legacy staff of Kauai Electric and tapped into NRECA for resources and training.

Responsiveness to stakeholders. Local ownership and control allow customer-owners the ability to exercise direct control over the actions of the utility and set goals unencumbered by the interests of private investors. However, such local governance is contingent on effective local community engagement in the affairs of the co-op and assumes that the local community is knowledgeable of co-op affairs and supportive of State goals.

In many mainland cases, there has been stagnating interest in the affairs of co-ops over time, as evidenced by declining percentages in the customers that vote on co-op affairs.[61] However, in the case of KIUC, overall turnout has been increasing and is generally higher than the average turnout at co-ops, residing at 23% for the last board election.[62]

[61] Institute for Local Self-Reliance, "Just How Democratic are Rural Electric Cooperatives?", January 13, 2016, available at: https://ilsr.org/just-how-democratic-are-rural-electric-cooperatives/

[62] Kauai Island Utility Cooperative, March 18, 2017, Board of Director Results, available at: http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/pr/2017-0318-OfficialElectionResults.pdf

Stakeholder Perspectives: Co-op Model

Some stakeholders consulted in this study felt that there were attractive elements of the cooperative utility model, particularly as a means of better aligning utility actions with community desires. However, many stakeholders also questioned the viability of transitioning to a cooperative model, for example regarding the amount of debt financing that would be required to make a compelling offer to HEI. There was a greater degree of interest apparent in the cooperative model on the neighbor islands (most notably the Big Island, where a cooperative entity has already formed with aspirations for eventual utility ownership) than on Oahu, which many local stakeholders felt was too large and complex for a cooperative model.

Regarding stakeholder involvement in utility decision-making, some KIUC members explained that low turnout does not necessarily mean that members do not care about the affairs of the utility. In fact, some members said that this instead reflects that these members trust the Board with its decision-making. Stakeholders also mentioned that there is generally higher voter turnout whenever there are contentious issues. That noted, in some cases, members advance proposals that are distracting or counterproductive. This can be challenging if there are unrealistic expectations of what the co-op can achieve amongst the local ratepayers.

Co-ops have unique characteristics that may make them an attractive vehicle for achieving State energy goals. However, these advantages come with additional challenges and obligations. The co-op model requires significant uptake in hiring and retaining expertise, which could be resolved through a detailed transition plan from the incumbent utility. Generally, the co-op offers the greatest control by local stakeholders, although this may come with its drawbacks if the local population is unengaged or uninterested on electric utility management, or opposed to the State energy goals.

7.2 Financial feasibility

The following analysis will focus on: (1) potential impacts on ratepayers and (2) whether the co-op entity is financially able to acquire the incumbent utility and fulfill its responsibilities and roles as an electric utility according to the State clean energy goals.

- **What are the relevant factors to consider for determining whether the new model is financially capable of acquiring the incumbent utility?**

Access to low-cost debt. In terms of the initial acquisition, members could contribute equity to the purchase of the utility assets, and the transaction is not significantly different from any other entity that seeks to purchase utility assets. In lieu of equity, the co-op could assume ownership by leveraging high amounts of debt, which is a more likely pathway for cooperative acquisition. For example, KIUC's debt to equity ratio is approximately 1.6 as of 2016. The cost of such debt

can vary, but generally between 1% and 5%.[63] Coops often have access to low-interest financing, which allows it to purchase assets at lower costs for its members. However, by relying primarily on debt for the purchase of utility assets, a cooperative utility may have difficulty in limiting rate increases during the repayment period.

But, even if co-op members are unable to contribute significant amounts of equity to the utility and subsequent improvements, co-op members have access to low-cost financing through both federal and cooperative lending sources. The USDA Rural Utilities Service ("RUS"), for example, has specific loan programs for increasing energy efficiency, renewables, and additional grant programs specifically for high-cost energy areas.[64] Other dedicated cooperative lenders, such as CoBank and the Cooperative Finance Association, also provide dedicated sources of financing to electric cooperatives. Finally, even if the co-op cannot own and operate all the projects itself, it can also procure them from other entities. These financing mechanisms can help co-ops secure the financing for Hawaii's clean energy vision while dampening any increase in the rates of consumers.

Overall, the virtue of the co-op model is that they have access to multiple sources of low-cost financing, which can help them to achieve the State energy goals at a reasonable cost. However, such financial benefits can be affected by the quality of management. KIUC, for example, attributes some of its cost reductions to a strong management focus on cost control, and it took several iterations of CEOs to achieve this strategy.

- **What benefits or costs would be accrued to ratepayers or taxpayers?**

Upside potential for ratepayers. As nonprofit entities, co-ops are generally less focused on securing profits and more focused on achieving the priorities of its customer-owners. This can take many different forms – for example, the co-op could return revenues above operating costs in the form of capital credits, greater investment in renewables, or lower rates. The benefits are determined by the priorities of the customer-owners.

Finally, it should be noted that the co-op is a currently regulated entity under the PUC in Hawaii. Therefore, its capability to raise rates and engage in certain projects is limited by external institutions, although KIUC is seeking greater latitude from PUC oversight.

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[63] See Kauai Island Utility Cooperative, "Consolidated Financial Statements, December 31, 2016 and 2015," Note 8-Long-term Debt, Page 17, available at: http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/financials/2016%20Audited%20Financial%20Statements.pdf.

[64] Tadlock Cowan, "An Overview of USDA Rural Development Programs," Congressional Research Service, February 10, 2016, available at: http://nationalaglawcenter.org/wp-content/uploads/assets/crs/RL31837.pdf

7.3 Legal feasibility

The following section assesses the co-op ownership model according to the standards outlined in Section 3.3. It assesses whether significant changes are necessary for the co-op ownership model, the governance structure for the operation of the co-op ownership model, and any additional legal considerations.

- **Is there a legal framework for this ownership model? Are any legal or regulatory changes necessary for this ownership model?**

Preexisting legal framework. There is a preexisting legal framework for co-op acquisition given the precedent established by the KIUC acquisition.

The transfer of utility assets from an IOU to a cooperative would be subject to PUC approval under HRS § 269-19, and the PUC would likely apply criteria similar to the criteria applied in the KIUC and NextEra matters (see section 4.3, above).

If the transfer is "unfriendly," eminent domain could potentially be used by the state or county to acquire IOU assets and then transfer them to various co-ops. The legality of this route; however, would be subject to questions about whether "cooperatization" is sufficiently "public" to allow for the use of eminent domain. Additionally, such an effort would require many of the same procedural steps described in Section 8.3, above, including an eminent domain court proceeding and potentially litigation over the extent of the PUC's jurisdiction.

If the transfer succeeds, HRS § 269-31 gives the PUC the power to decide whether the co-op will be subject to post-transfer PUC regulation:

> Notwithstanding any provision of this chapter or any franchise, charter, law, decision, order, or rule to the contrary, the public utilities commission, sua sponte or upon the application of an electric cooperative, may waive or exempt an electric cooperative from any or all requirements of this chapter or any applicable franchise, charter, decision, order, rule, or other law upon a determination or demonstration that such requirement or requirements should not be applied to an electric cooperative or are otherwise unjust, unreasonable, or not in the public interest. Notwithstanding the above, the public utilities commission and the consumer advocate shall at all times consider the ownership structure and interests of an electric cooperative in determining the scope and need for any regulatory oversight or requirements over such electric cooperative. To the extent any other provision of this chapter or any franchise, charter, law, decision, order, or rule is contrary to or otherwise conflicts with this section in any manner, the provisions of this section shall govern and apply.

KIUC has remained subject to PUC regulation, as KIUC has not affirmatively sought complete de-regulation. However, the PUC's regulation of KIUC has differed in significant respects from the HECO Companies in the last few years, with KIUC generally being subject to "lighter"

regulation. For example, only the HECO Companies, not KIUC, were required to undertake a "Power Supply Improvement Plan" process.

- **What governance structures would be necessary for this new ownership model to function as intended?**

Local governance through elections. The creation of these entities would entail establishing a governance structure, including a board, and an election process for board members.

- **Are there any additional legal considerations for the viability of this new ownership model?**

Farm bill population limits on "rural." Some sources of co-op funding can be subject to specific requirements. For example, with regards to RUS funding, low-interest RUS Electricity and Telecommunications Loans are generally only available for areas with populations smaller than 20,000, which would allow for island-wide cooperatives only on Molokai and Lanai. Additionally, the RUS rules contain certain density requirements and other provisions that would require further research.

> That said, the 2008 federal farm bill amended the definition of "rural area" in 7 U.S.C. 1991(G) to provide that "within the areas of the County of Honolulu . . . the Secretary [of the U.S. Department of Agriculture] may designate any part of the area as a rural area if the Secretary determines that the part is not urban in character, other than any area included in the Honolulu Census Designated Place."[1] If this definition applies to electric co-op funding, it could allow the funding of cooperatives in certain areas of O`ahu with populations larger than 20,000 people, but would not allow the creation of an island-wide cooperative on O`ahu, or alter the analysis on any other island.

KIUC is exempt from these requirements since there is a "once rural, always rural" exception for those entities that have received such loans in the past. While this does not eliminate all sources of capital for cooperatives, this is a relevant consideration for the establishment of co-ops that aim to serve certain highly populated areas.

Further analysis of these rules and discussions with the relevant federal agencies are required to determine the types of federal financing that might be used in support of a "cooperatization" movement in Hawaii.

7.4 Conclusion

In terms of implementation, the co-op benefits from the regulatory history in Hawaii, which has already overseen the acquisition of utility assets by KIUC. This provides some predictability in the requirements of such an acquisition. Once the co-op is in service, the co-op can also utilize its access to various support networks and other resources to ensure a smooth transition towards becoming a functional entity. Subject to its legal classification as "rural," the co-op also can secure debt at low rates from institutions such as the RUS. Finally, the co-op allows consumers to directly control utility functions, aligning stakeholder needs. However, this control comes with its

caveats; consumers may not always be interested in utility functions, leading to imprudent decision-making.

Figure 6. Cooperatives: Feasibility Criteria Summary

Criteria	Categorization	Various Considerations
Technical feasibility	Implications for the role and responsibilities of the utility	(+/-) No significant changes
	Assumption of utility responsibilities	(+) Access to support networks
		(-) Possible disruption of the workforce
	Achievement of State clean energy goals	(+/-) Subject to implementation and context
		(+/-) Possibility of increased innovation (subject to PUC)
		(+) Increased responsiveness to local stakeholders
Financial feasibility	Impacts on ratepayers	(+/-) Subject to local priorities
		(+/-) Regulation by PUC
		(+) Capital credits returned to customer-owners
	Cost factors for initial acquisition	(+) Access to low-cost debt
	Cost factors for achieving State clean energy goals	(+) Access to low-cost debt
Legal feasibility	Existence of supporting framework	(+) Pre-existing legal framework
	Governance requirements	(+/-) Local governance through elections
	Additional legal factors	(-) 20,000 population cap on RUS funding
	Additional legal factors	(+/-) May or may not be subject to PUC regulation

8 Single Buyer

The origins of the single buyer model in the U.S. lie in PURPA, which as described above required previously-vertically integrated utilities to purchase electricity at avoided cost rates from independent power producers. In the years following PURPA, many jurisdictions developed competitive procedures to determine the prices at which utilities would procure power from IPPs, and planning procedures (such as integrated resource planning) to determine the amount of electricity that should be procured.[65] For at least the last decade, Hawaii has followed an SB model of this type. Utilities procure electricity from IPPs under long-term PPAs, according to the procedures set forth in the Competitive Bidding Framework, or by waivers therefrom.[66]

During the restructuring movement of the 1990s (described above), FERC and a number of states determined that the utility-based SB model did not do enough to correct utility incentives to use their role as system operator to favor their own generation over that of IPPs.[67] In the 1990s, restructuring architects debated two principal alternative paths towards creating Regional Transmission Organizations that would improve incentives:

- The "Transco" model, implemented in England and Wales but not the U.S., leaves for-profit utilities with ownership of "wires" infrastructure and control of the grid, but requires them to divest ownership of all generation, and forbids them from owning any new generation.[68]

- The "ISO" model, implemented in all restructured areas of the U.S., leaves utilities with *ownership* of transmission infrastructure but cedes *control* of the grid to a non-profit, federally-regulated ISO. In the ISO model, utilities may still be allowed to own generation, but they are prevented from favoring it, since they no longer control the interconnection and dispatch of generation. [69]

To be clear, the goal of these proposals on the mainland was not to create an SB model, but to facilitate the emergence of "many-to-many" wholesale electricity markets. Specifically, the vision was that multiple IPPs on the sell side of the market would be able to transact at competitive rates with multiple potential buyers, including IOUs, munis, electricity traders, large industrial customers, and competitive retailers (where allowed). The electricity would be transmitted

[65] See note 28.

[66] See Section 3.3, above.

[67] See note 29 and 30.

[68] SALLY HUNT, MAKING COMPETITION WORK IN ELECTRICITY (2002).

[69] SEVERIN BORENSTEIN AND JAMES BUSHNELL, ENERGY INSTITUTE AT HAAS WP 252R, THE U.S. ELECTRICITY INDUSTRY AFTER 20 YEARS OF RESTRUCTURING (2015), https://ei.haas.berkeley.edu/research/papers/WP252.pdf.

between these parties over the utility-owned wires infrastructure at nondiscriminatory, regulator-determined, transmission-only "postage stamp" rates.

Nevertheless, some of the techniques developed during restructuring (ISOs, divestiture of generation, functional unbundling, etc.) could also be used to create an SB model for Hawaii with better incentives than the PURPA or current Hawaii competitive bidding models.

As discussed in Task 1.1.1/1.2.1, the improved SB model for Hawaii has different variants. First, the SB can still be within the utility, but surrounded by appropriate ring-fencing mechanisms, which include separation of the SB's operations and accounts from the incumbent's other business entities, and limited or no sharing of information. Second, the SB can be an independent entity outside of the utility. Ideally, these improved SB models would seek to be technology and ownership model neutral and strive to procure electricity to meet demand at least cost. This would require regulatory changes that would allow for greater competition in the generation space. The implications of this regulatory change will be discussed in future analysis, particularly in Task 2.

8.1 Technical feasibility

The following section evaluates the single buyer ownership model according to the standard of technical feasibility. It offers a high-level evaluation regarding the two questions outlined in Section 3.1., outlining the major key factors that would impact outcomes.

- **Will this new ownership model change the roles and responsibilities of the utility? Would this require additional infrastructure or capabilities?**

There are a number of potential models for improving Hawaii's existing SB framework, each of which would possess unique characteristics and would have distinct needs:

- *Separation of generation and wires entities (structural unbundling).* One option is to require the utility to divest its generation to a separate owner or owners. This effects an even stronger separation between generation ownership and "wires" ownership, removing entirely the utility's incentive to use ownership of wires in a way that favors its generation.

- *SB group is ring-fenced from the other utility's business entities.* Another option is that the SB division of the current utilities is ring-fenced from the other business entities of the incumbent utility. In this model, there is no divestiture of generation assets. These ring-fencing mechanisms include separation of operations (such as staffing, work space, and information technology, to name a few), separation of accounts (i.e. accounting records), and limited sharing of information. The roles of the ring-fenced SB include being responsible for the management of electricity procurement and related services, preparing demand forecast reports and long-term energy plans, promote transparency in the performance of its functions and to facilitate competition in the generation sector, to name a few.

- *Transfer of procurement authority to an independent entity.* Alternatively, the SB entity can take a form different from a utility, such as a non-profit, independent entity. One example of this is the Ontario Power Authority before it merged with the Independent Electricity System Operator in 2015. The OPA acted as the principal buyer and procurement company for all new supply- and demand-side electricity resources in Ontario.[70] It is also responsible for long-term power system planning. In Hawaii, there is a precedent for the creation of such an entity: in 2007 the PUC took the responsibility for promotion and administration of demand-side energy efficiency programs from Hawaii utilities and transferred it to a separate entity. This step isolated the energy efficiency programs from utility disincentives to embrace efficiency.[71]

- **Will the ownership model be able to comply with the reliability, adequacy, and quality of service standards established by the PUC?**

No significant changes. There is no reason to believe that the ability of the utility to comply with reliability, quality of service, and supply adequacy would be impacted if the SB division is ring-fenced or be outside of the utility. In fact, under the SB model, one of SB's roles is to facilitate generation competition so there would be no negative impact on this under the SB model.

Opportunity for improvements in procurement efficiencies. Over the long-term, there is no reason to believe that the SB would not be able to procure energy in a way that would meet the renewable mandate. Depending on the nature of contracts and procurement, this could increase competition for energy generation efficiently. The SB could also offer an opportunity to reform the procurement and post-competitive bidding PPA negotiation and PUC approval processes, which has come under increasing scrutiny in Hawaii.[72] Housing this process in the SB could offer an opportunity to make it more efficient (though that outcome is not assured). The overall effect of the SB on other State goals, such as grid modernization, is neutral.

Overall, the SB model requires a change in the role that could also require additional infrastructure and capabilities. The extent of this additional infrastructure depends on the configuration of the SB. However, this change in the role allows for Hawaii to take additional steps towards establishing a deregulated electricity market, which could support the achievement of its state objectives of innovation and greater competition. Moreover, this change would align with the Inclinations of the PUC, which have explicitly noted the possibility of altering the traditional role of the incumbent utility in generation.

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[70] Includes nuclear, conventional natural gas, renewables, as well as conservation and demand management.

[71] HRS §§ 269-121 - 269-124; Decision and Order No, 23258, filed on February 13, 2007, in Docket No. 05-0069. The entity is known as "Hawaii Energy," https://Hawaiienergy.com/.

[72] For example, in the ongoing RFP proceeding (Docket 2017-0352), the Commission has solicited feedback from stakeholders on how to improve the HECO Companies' proposed procurement techniques, including PPA negotiation.

8.2 Financial feasibility

The following analysis will focus on: (1) potential impacts on ratepayers and (2) whether the SB entity is financially able to fulfill its responsibilities and roles as an electric utility according to the State clean energy goals.

- **What are the relevant factors to consider for determining whether the new model is financially capable of acquiring the incumbent utility?**

Requires set-up costs. Regardless of the variant of SB, there will be set up costs involved. Under an SB where it is still part of the incumbent utility, set up costs would include a separate office for the SB, IT infrastructure, and other ring-fencing mechanisms to ensure that the SB is independent of the utility. Under an SB where it is outside of the utility, additional infrastructure investments need to be made. Although the final cost of establishing an SB is unclear due to its many variations, housing the SB within the incumbent utility might hypothetically be less expensive due to the preexisting role that incumbent utilities already play in procuring generation from IPPs in Hawaii. If another entity undertakes that role, it would have to develop and acquire that expertise and need to invest in infrastructure to operate the SB.

- **What benefits or costs would be accrued to ratepayers or taxpayers?**

Facilitating competition. The ideal outcome from an SB model is the improved incentives to create a competitive procurement process that lowers the prices of generation, which would be reflected in lower consumer rates and the transparency. This also assumes that there is a competitive market of generation companies in Hawaii competing for projects. That appears to be a realistic assumption, given that in its most recent major competitive procurement, HECO received bids from at least 25 separate IPPs,[73] and that numerous IPPs filed comments expressing interest in the HECO Companies' proposed upcoming RFP.

Depends upon procurement practices. However, the benefits or costs accrued to ratepayers or taxpayers can often depend on the details of how the SB is managed and its procurement contracting mechanisms. The SB is assumed to negotiate the terms and conditions of the generator contracts in a fair and reasonable manner that does not discriminate against any party.

- **Can the new ownership entity achieve the State energy goals at a reasonable cost?**

Greater competition in generation. There is no reason to believe that the SB would be unable to achieve the State energy goals at a reasonable cost. The SB Rules in which the SB will need to comply with, would specify SB's role in facilitating competition in the generation sector by tendering for new capacity in a fair and balanced manner and ensuring that it performs its

[73] Docket No. 2013-0156, Order No. 31913 at p. 4. filed February 13, 2014; Docket 2013-0381, Order No. 32241 at p. 7, filed August 4, 2014.

dispatch functions. The SB will continue to be guided by State policy goals, which will be reflected in its procurement decision-making.

8.3 Legal feasibility

The following section assesses the SB ownership model according to the standards outlined in Section 3.3. It assesses whether significant changes are necessary for the SB ownership model, the governance structure for the operation of the SB ownership model, and any additional legal considerations.

- **Is there a legal framework for this ownership model? Are any legal or regulatory changes necessary for this ownership model?**

Requires establishing a supporting legal framework, including supporting the legislation. The current legal framework in Hawaii implements a version of the Single Buyer model in which the utility serves as a single buyer of IPP electricity under long-term PPAs. Specifically, the utility is required by the Competitive Bidding Framework (and sometimes by PURPA) to procure new generation needs from IPPs rather than developing new utility-owned generation, unless it can persuade the PUC to allow it to develop its own generation under a waiver from the Competitive Bidding Framework, or succeeds in proposing a utility-owned project that "wins" a Commission-supervised competitive bidding proceeding (which has not happened since the promulgation of the Competitive Bidding Framework).

At the same time the utility serves as Single Buyer, however, it continues to serve as the system operator, interconnection authority, transmission and distribution system owner, and owner of legacy generation. Moreover, the utility continues developing and rate-basing new generation when it is able to do so.[74]

This legal framework allows the utility to use its monopsony power (as well as its power as system operator and interconnection authority) to achieve its favored outcome in interactions with IPPs. It appears the utility will continue to seek to develop new utility-owned generation projects –it has recently announced a new corporate strategy focused on that objective.[75] Thus,

[74] See, e.g., Docket No. 2016-0342 (HECO Application for Waiver from the Framework for Competitive Bidding And to Commit Funds in excess of $2,500,00 (excluding Customer Contributions) for the Purchase and Installation of Item P0003966, West Loch PV Project)); and Docket No. 2014-0113 (HECO Application for Approval to Commit Funds in Excess of $2,500,000 (Excluding Customer Contributions) for the Purchase and Installation of Item P0001756, Schofield Generation Station Project).

[75] On a recent earnings call, HEI disclosed that it is now "focused on our enterprise-wide strategy to develop and invest in opportunities" to own generation. HEI stated that the first investment in this campaign will be its purchase of the Hamakua Energy Partners facility through an unregulated subsidiary, which purchase the PUC denied when it was earlier attempted by HELCO. The earnings call transcript is

the utility may have an inherent incentive to resist doing business with IPPs, in order to preserve the opportunity to complete its own projects instead.

In an attempt to address the utility's incentives, on April 6, 2018, the PUC established a Performance Incentive Mechanism ("PIM") to incentivize HECO Companies to successfully procure low cost renewable energy.[76] In short, the PIM is designed as a "shared-savings" incentive mechanism, where the "first year savings" obtained from each PPA is first determined, and then those "savings" are "shared" between the customers (80%) and the HECO Companies (20%).[77]

In addition, on April 18, 2018, PUC embarked on a broader effort to establish appropriate incentives for the HECO Companies by opening an investigative docket to consider Performance-Based Regulation ("PBR").[78] The PUC recognized that since the Hawaii electric power industry is transitioning from centralized fossil-fuel-based generation to more distributed and renewable generation, the utility's role and the regulatory framework must also evolve. PBR would enable the PUC to reform legacy regulatory structures to enable innovations within modern power systems.[79] Essentially, instead of incentivizing investment in capital expenditures for which the utility may earn a rate of return and profit under traditional "cost-of service regulation",[80] PBR would instead provide rewards for specific outcomes and objectives to align utilities' interests with the public interest, and still provide the utility with an opportunity to earn a fair rate of return.[81]

Furthermore, the State has enacted the Hawaii Ratepayer Protection Act, which was signed into law on April 24, 2018,[82] and will take effect on July 1, 2018.[83] The purpose of this act is to "is to

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available at https://seekingalpha.com/article/4119904-Hawai'ian-electric-industries-ceo-connie-lau-q3-2017-results-earnings-call-transcript.

[76] See, Order No. 35405 "Establishing A Performance Incentive Mechanism for Procurement in Phase 1 of the Hawaiian Electric Companies' Final Variable Requests for Proposals", issued in Docket No. 2017-0352, filed on April 6, 2018 ("Order No. 35405")

[77] See, Order No. 35405, at 11-14.

[78] See, Order No. 35411, Instituting a Proceeding to Investigate Performance-Based Regulation, issued in Docket No. 2018-0088, on April 18, 2018 ("Order 35411").

[79] See, Order 35411, at 3, 13-27.

[80] See, Order No. 35411, at 10-13.

[81] See, Order No. 35411, at 3-4

[82] Gov. Msg. No. 1105, SB2939 SD2, Relating to Energy, Act 5.

[83] Hawaii Ratepayer Protection Act, 2018 Haw. Sess. Laws Act 5.

protect consumers by proactively ensuring that the existing utility business and regulatory model will be updated for the twenty-first century by requiring that electric utility rates be considered just and reasonable only if the rates are derived from a performance-based model for determining utility revenues."[84] The PUC is required by the Ratepayer Protection Act to "establish performance incentives and penalty mechanisms that directly tie an electric utility revenues to that utility's achievement on performance metrics and break the direct link between allowed revenues and investment levels" by January 1, 2020. [85]

Thus, the current legal framework relevant to the SB model is undergoing significant changes due to the PIM, PBR, and Hawaii Ratepayer Protection Act matters and issues described above. Hawaii's existing SB model is hampered by incentives issues, and improvements thereto would require adjustments to applicable law and/or rules, such as functional unbundling, structural unbundling, or creation of a new independent procurement entity, in addition to the PIM, PBR, and the Hawaii Ratepayer Protection Act matters and issues being implemented and/or considered as described above. The legal steps that would be required to implement these changes vary based on the sub-model selected. Some can be implemented by the PUC alone; most will require legislative enactment. These steps will be discussed in more detail in future work, when the desired characteristics of an improved SB model are more fully fleshed out.

Lastly, the PUC will continue to play a central role in ensuring that generation is procured competitively, that the exercise of market power is mitigated, that risks are allocated appropriately and managed prudently, and that the buyer remains creditworthy.

What governance structures would be necessary for this new ownership model to function as intended?

Requires independence from generation, political, and operational interests. The SB must be independent of any influences from the interests of generation companies. As noted, if the utility continues to play the role of the SB, there will need to be improved ring-fencing regulations in place to prevent the generation assets from influencing the behavior of the SB. Finally, it is preferable that such an institution is independent of political interests in its day-to-day operations, while still adhering to the State clean energy goals. Ideally, dispatch and the SB operation are sufficiently segregated and independent of one another. If this is not the case, then the competitive nature of the market will be compromised.

- **Are there any additional legal considerations for the viability of this new ownership model?**

[84] Hawaii Ratepayer Protection Act, 2018 Haw. Sess. Laws Act 5, § 1.

[85] Hawaii Ratepayer Protection Act, 2018 Haw. Sess. Laws Act 5, § 2.

Other than the major legal considerations outlined above, any additional legal considerations will be included in Task 1.3.2, subject to the final ranking of the SB model.

8.4 Conclusion

Improvements to the SB model would be an incremental, logical step forward in the direction Hawaii's electricity sector has been moving in recent years. However, such a step would still require shift in regulatory frameworks, including new roles for both the incumbent utility and the regulator. Depending on the specific reforms implemented, these shifts may require legislation. If implemented in a way that does not increase administrative cost or endanger reliability, the SB model could potentially reduce energy prices by correcting the incentives that currently hamper robust competition in Hawaii's wholesale electricity market. Such competition may also allow for increased innovation in the development of generation projects. It would also still allow for a significant state role in guiding overall energy procurement through the IRP process, and the PUC would still be able to establish criteria for energy projects that reflected the public interest. Finally, the SB model can potentially be an initial step towards greater wholesale and potentially even retail competition in electricity.

Figure 7. Single Buyer: Feasibility Criteria Summary

Categorization	Various Considerations
Implications for the role and responsibilities of the utility	(+/-) Subject to realignment method (function unbundling, structural unbundling, independent entity)
Assumption of utility responsibilities	(+/-) No significant changes
Achievement of State clean energy goals	(+) Realignment of utility incentives (+) Possible greater innovative flexibility (+) Possible procurement efficiency improvement
Impact on ratepayers	(+/-) Depends on role provided to SB but most likely better terms since SB is independent
Cost factors for initial acquisition	(+/-) Requires some investments for ring-fencing mechanisms (for SB within the utility) or new capital expenses (for SB outside of the utility)
Cost factors for achieving State clean energy goals	(+) Realignment of utility incentives
Existence of supporting framework	(+/-) Existing framework, but requires significant additional regulatory or legislative reform
Governance requirements	(+/-) Requires independence from political and generation interests
Additional legal factors	Not applicable

9 Integrated Distributed Energy Resources Provider ("IDER")

In an IDER model, the grid also functions as a platform for a market in which customers and market actors interact with utility-scale generators and DERs. In an IDER model, there is a system operator whose roles include overseeing the transactions and system planning. Under an IDER model, the utility could be the IDER system operator or there is an independent (third-party) IDER system operator outside of the utility. If the utility is also the IDER system operator, the incumbent utility needs to divest its generation assets to eliminate conflict of interests and level the playing field. However, it would continue to own its transmission and distribution assets.

The IDER model assumes a diversity of ownership structures for generation where IPPs, IOUs, co-ops and other ownership structure co-exist. As noted in the previous working papers, the driver to making the IDER work is to appropriately implement open access and properly unbundling existing utility costs. These concepts will be discussed in detail in the regulatory models working papers (under Task 2).

9.1 Technical feasibility

The following section evaluates the IDER ownership model according to the standard of technical feasibility. It offers a high-level evaluation regarding the two questions outlined in Section 3.1., outlining the major key factors that would impact outcomes.

- **Will this new ownership model change the roles and responsibilities of the utility? Would this require additional infrastructure or capabilities?**

Redefined role of the utility. The IDER model would fundamentally change the roles and responsibilities of the utility, in effect requiring the utility to divest from its generation assets. Thus, the utility would serve as a "wires-only" utility, ensuring open access to the network while recovering its costs. In addition, the utility is no longer incentivized to expand its network and operations, but rather is compensated based on its ability to meet a set of performance requirements, such as providing data to third party service providers, facilitating the interconnection of renewables or storage technologies, and enabling demand-side resources to better participate in the electricity market.

Requires additional infrastructure and expertise. As discussed in Task 1.1.4, additional infrastructure is needed to implement the IDER model. These include investments in new technologies like blockchain and infrastructure that will facilitate market participation for customers, DER providers, and other service providers.

- **Will the ownership model be able to comply with the reliability, adequacy, and quality of service standards established by the PUC in the short and long-term?**

Subject to price recovery. If the utility can recover the price of grid maintenance and expansion and appropriate regulations are made to incentivize DER resources, it is possible that the utility can meet the reliability, adequacy, and quality of service standards established by the PUC. Of course,

the feasibility of this model will depend on the maturity of various DER technologies and their provision of various energy services.

Possible requirement of an ISO-like entity. Over the long term, if Hawaii seeks to achieve its clean energy vision through an increasingly competitive and diverse distributed energy system, it may eventually seek an entity with the capabilities of an ISO that could evaluate the high penetration of intermittent resources and determine how to procure them at least cost. It should be noted that there is already some prior institutional precedent for establishing an ISO-like organization in Hawaii. The 2012 Hawaii legislature enacted Act 166, which authorized the commission to adopt reliability standards and interconnection requirements, and to contract with a Hawaii Electricity Reliability Administrator ("HERA"). However, the Commission has not yet promulgated any standards or requirements under the Act, and has not yet appointed a HERA.[86]

Infrastructure improvements. Over the long-term, this ownership model would necessitate grid modernization by default to accommodate the significant increase in bidirectional flows and intermittency on the electricity system. When coupled with these infrastructure and regulatory changes, the IDER system would allow for greater latitude for innovation and competition in the provision of energy services. If the value of DERs is sufficiently granular, this would also encourage resource diversity across time and geographies. In doing so, such a model would allow both producers and consumers to benefit from the enhanced value streams of DERs. It may also empower consumers to assume the role of producers, in effect potentially generating revenue streams from their localized uses of energy.

Finally, it is worth noting that the IDER model aligns well with the Inclinations of the Public Utilities Commission, which explicitly notes the importance of DERs. It also aligns with the Inclinations in that it redefines the utility's role in generation assets.[87]

Overall, the IDER model offers one potential route for achieving the State's energy goals that remain somewhat unexplored, both in Hawaii and on the mainland. It would require significant investments to establish the institutions and infrastructure necessary for a successful IDER market. However, it would allow for greater innovation, competition, and clean energy procurement, and aligns closely with the PUC Inclinations.

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[86] The PUC has, however, led other policy work on reliability, DERs interconnection, and DERs policy in general. A few years ago, the PUC organized a Reliability Standards Working Group to assist with the development of standards and interconnection requirements, particularly as they related to distributed generation. Currently, the PUC also has an open docket on grid modernization (2016-0087), in which it is considering many issues related to management of DERs, as well as an ongoing general DERs policy docket (2014-0192), in which it is setting compensation and interconnection policy for DERs.

[87] Hawaii Public Utilities Commission, "Exhibit A: Commission's Inclinations on the Future of Hawaii's Electric Utilities," Docket No. 2012-0036, Decision and Order No. 32052, filed on April 28, 2 014, ("Order No. 32052"), available at https://puc.hawaiiHawai'i.gov/wp-content/uploads/2014/04/Commissions-Inclinations.pdf, p. 18.

9.2 Financial feasibility

The following analysis will focus on: (1) potential impacts on ratepayers and (2) whether the IDER entity is financially able to fulfill its responsibilities and roles as an electric utility according to the State clean energy goals.

- **What are the relevant factors to consider for determining whether the new model is financially capable of acquiring the incumbent utility?**

Initial costs. The IDER model entails set up costs to build the platform and the infrastructure needed for the customers, DER providers, and other market participants to transact. NY has done some pilot programs on IDER. One of these programs is the Buffalo Niagara Medical Campus DSP Engagement Tool where the hospital campus is used as a test-bed for the distributed system platform ("DSP") functionalities and used to coordinate and optimize the DERs throughout the campus. This pilot program's capital expenditure is $4.4 million, and the operations cost are $385,000 for a less than 3-year period.[88]

Data adequacy. It is difficult to assess a reasonable cost for the IDER model given it is still an ownership model in progress with no clear precedent. If the value streams from DERs are monetized, and markets are established for such services, it is possible that the State could achieve its clean energy goals at a reasonable cost. However, this is by no means ensured, and there are not many relevant studies that would indicate the total costs of such a transition, let alone for Hawaii. Therefore, the final determination on this metric is unclear.

For financial feasibility, it is difficult to assess the overall outlook for the IDER model due to insufficient data. However, the idealized version of the IDER model should be able to exploit value streams and deliver such benefits to ratepayers through an efficient and competitive marketplace. In doing so, it could achieve the State's clean energy goals at market-based prices. However, the cost to establish the institutions to govern this market is not unsubstantial.

- **What benefits or costs would be accrued to ratepayers or taxpayers?**

Insufficient data. Determining the financial feasibility of the IDER approach is a challenging task. Is it unclear how costly the overall transition would be, given the lack of empirical data. One could look at cost-benefit tests, but such an approach would require a detailing of various utility and state programs that are either undeveloped or undetermined. For example, New York has decided that spending time on a broad cost-benefit analysis test of the totality of its REV approach would be counterproductive, instead choosing to focus on its expenditures during the phased implementation of REV, with the goal of recognizing benefits and costs with increasing specificity over time.

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[88] National Grid. Distributed System Platform REV Demonstration Project Q2 2017. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BFF2D4106-57EE-469A-A32C-201ABAFB1BE2%7D

Possible value streams. We are unable to outline a cost estimate of this model beyond an initial estimate of the cost of establishing an ISO, due to uncertainty in what exactly this model might entail. However, there have been numerous studies that have outlined the various "values" of DERs. Many of these values would be transferred to consumers and other businesses. Aside from the value of energy, additional value includes various grid services (ancillary services, capacity), resiliency attributes, etc., each of which will vary according to location and the time value of its production. Moreover, it is anticipated that further integration of DERs could decrease the need for further transmission and distribution investments, which would also be savings for consumers.

Greater price volatility. One of the downsides of increasing the granularity of prices across time and location could potentially be greater price volatility, particularly given the intermittency of renewable resources. This price volatility can potentially harm consumers by undermining predictability in their costs of energy. However, it can also serve as a strong financial incentive for other DERs, such as demand response and battery storage.

9.3 Legal feasibility

The following section assesses the IDER ownership model according to the standards outlined in Section 3.3. It assesses whether significant changes are necessary for the IDER ownership model, the governance structure for the operation of the IDER ownership model, and any additional legal considerations.

- **Is there a legal framework for this ownership model? Are any legal or regulatory changes necessary for this ownership model?**

Requires significant regulatory and legal changes. The current legal framework in Hawaii does not support the IDER model. Although states across the United States are taking steps to achieve this model, the approaches of the different states have varied widely.

Significant legal and regulatory changes are necessary to fully implement the IDER model. Once the IDER model is defined more precisely, which will be done in Task 2, we will explore the legal issues raised as part of subsequent tasks. Such issues may include questions such as what legal reforms, if any, are necessary to allow for wholesale or "peer-to-peer" energy transactions across utility-owned grids, whether the formation of an ISO-like entity would require legislative action or could be set up by the PUC under existing authority, and questions related to the handling of stranded costs from the prospect of utility divestment in generation resources.

- **What governance structures would be necessary for this new ownership model to function as intended?**

For the IDER model to function effectively, it would require an elimination of conflicts of interest between asset owners and electricity grid owners. Ideally, it would also ensure the independence of the IDER that operates and manages the market for various services that DERs provide the grid.

- **Are there any additional legal considerations for this new ownership model?**

Other than the major legal considerations outlined above, any additional legal considerations will be included in Task 1.3.2. if this model is recommended.

9.4 Conclusion

The IDER model explores the possibility of establishing a system in which consumers can generate power at the point of consumption, leading to greater bidirectional flows in the power system. This is a significant change from the general orientation of electricity services, which has traditionally been unidirectional. As such, the IDER model would require significant changes in regulation and legislation and has yet to be fully implemented in other states. However, it holds potential for aligning stakeholder interests and increasing the overall penetration of renewables, particularly since it would open new value streams and markets for DERs.

Figure 8. IDER: Feasibility Criteria Summary

Criteria	Categorization	Various Considerations
Technical feasibility	Implications for the role and responsibilities of the utility	(+/-) Separation of wires from generation
		(-) Requires additional infrastructure
	Assumption of utility responsibilities	(+/-) Subject to implementation
	Achievement of State clean energy goals	(+/-) Subject to implementation
		(+) Possibility of increased competition
		(+) Possibility of increased innovation
		(+) Increased responsiveness to local stakeholders
Financial feasibility	Impacts on ratepayers	(+/-) Insufficient empirical data
		(+) Possible value streams from DERs
		(-) Increased price volatility
	Cost factors for initial acquisition	(-) Startup costs (i.e. ISO-like institutions and infrastructure)
	Cost factors for achieving State clean energy goals	(+/-) Insufficient empirical data
Legal feasibility	Existence of supporting framework	(-) Requires significant regulatory changes
	Governance requirements	(+/-) Must address conflicts of interest
	Additional legal factors	Not applicable

10 Grid defection

In the grid defection (or dispersion of ownership) model, consumers choose to defect entirely from the grid, encouraged by the declining costs in behind-the-meter "(BTM") generation, rising retail electricity costs, and other advances in distributed energy resources. This model assumes that regulators and utilities have failed to update regulations and incentives to encourage ratepayers to stay with the grid and that technologies have advanced to the degree that defection is not only possible but economical. This scenario would then allocate the remaining costs of the electricity grid on those who cannot afford, or who are unwilling, to defect from the grid. It would possibly lead to the abandonment of large portions of the grid and asset underutilization.

In the immediate short-term, it is unlikely that consumers will defect from the grid *en masse*, in large part because the economics are prohibitive for most consumers, particularly for energy storage. However, absent the necessary regulatory and policy changes, grid defection increasingly is a more probable and likely possibility as solar and storage costs decrease. Moreover, there is a relatively high risk of grid defection in Hawaii because the retail costs of electricity are the highest in the nation.[89]

10.1 Technical feasibility

The following section evaluates the grid defection model according to the standard of technical feasibility. It offers a high-level evaluation regarding the three questions outlined in section 3.1.

- **Will this new ownership model change the roles and responsibilities of the utility? Would this require additional infrastructure or capabilities?**

The role of the utility remains unchanged. The role and responsibilities of the utility will remain unchanged. While in a certain sense, the responsibilities may change in that in that they will no longer be responsible for a significant number of energy consumers that were previously drawing energy from the electricity grid, the utility will remain responsible for generation, transmission, and distribution, and meet PUC standards for electricity service.

- **Will the ownership model be able to comply with the reliability, adequacy, and quality of service standards established by the PUC?**

Unable to comply with reliability and quality of service. This model is unlikely to be able to fully comply with the reliability, adequacy, and quality of service standards established by the PUC. As a larger number of defectors leave the grid, and if rates cannot rise quickly enough to recover the costs of the grid, portions of the grid may atrophy, leading to reliability, safety, and quality of service concerns. While there will likely be an adequate generation for the remaining consumers, the network costs and overhead costs will be substantial, given the reduced number of customers.

[89] Energy Information Administration, State Electricity Profiles, January 17, 2017, available at: https://www.eia.gov/electricity/state/

Unable to achieve clean energy goals over the long-term. Over the long-term, grid defection would impede the achievement of Hawaii's clean energy goals significantly, for a variety of reasons. Even if a significant number of consumers can defect from the grid, many other consumers will be unable to do so and will continue to rely on the utility for electricity services. It is unclear how renewable the remaining assets of the utility will be, particularly if utilities lose a large portion of their revenue stream from grid defectors and are unable to invest in cleaner technologies. In terms of other state goals, this would undermine the ability of the utility to modernize the grid and participate in innovative pilot projects.

Overall, it is extremely unlikely that the grid defection model would be able to achieve the State's clean energy goals. The utility would suffer financially, crippling its ability to make investments in renewable projects, make grid improvements, and meet the standards of the PUC. Lower-income households would bear the brunt of the cost of the electricity grid.

10.2 Financial feasibility

The following analysis will focus on: (1) potential impacts on ratepayers and (2) whether grid defection would fulfill the responsibilities and roles of an electric utility according to the State clean energy goals.

- **What are the relevant factors to consider for determining whether the new model is financially capable of acquiring the incumbent utility?**

In this scenario, utility assets remain with the incumbent utility. Moreover, there is an underutilization of utility assets, with grid defectors purchasing their self-encapsulated energy systems to generate energy. Houses that can afford to defect from the grid can do so with existing resources and financing routes. However, lower-income households cannot afford to defect from the grid.

Unable to finance long-term goals. Even if this model could achieve the State energy goals, it would not do so at a reasonable cost. This is because the utility will face a "death spiral" as it is increasingly encumbered to pay for assets that are no longer generating revenue. In this case, the utility will find it hard pressed to pay for any necessary investments in infrastructure or capacity, particularly if the PUC rejects significant rate increases to pay for such assets.

Financially, the grid defection model would impact remaining customers of the utility. More specifically, to ensure that the utility will be able to recoup its investments and continue its operations, it would need to charge higher rates to the remaining customers.

- **What benefits or costs would be accrued to ratepayers or taxpayers?**

Significant costs to lower-income households. The costs of grid defection are borne virtually entirely by consumers who still stay with the utility. Because there will be fewer customers with the same fixed costs and revenue requirements needed to run the transmission and distribution grids, the remaining consumers who stay with the grid will pay higher electricity rates. As noted above, the impacts on ratepayers will be varied, with some consumers no longer classified as ratepayers,

and the remaining ratepayers burdened with an increased share of grid maintenance costs. There is likely to be a significant income disparity in how energy consumers are allocated amongst these groups. Grid defection would have particularly harmful impacts on lower-income households that cannot afford the cost of a behind-the-meter system that addresses all their energy needs.

10.3 Legal feasibility

The following section assesses the grid defection model according to the standards outlined in Section 3.3. It assesses whether significant changes are necessary for the grid defection model, the governance structure for the operation of the grid defection model, and any additional legal considerations.

- **Is there a legal framework for this ownership model? Are any legal or regulatory changes necessary for this ownership model?**

No significant legal impediments. While there is not necessarily legal "framework" for this ownership model, there is no legal constraint that bars defection from the grid, other than regulatory codes that determine the placement and use of solar and battery storage technologies.

- **What governance structures would be necessary for this new ownership model to function as intended?**

No significant governance requirements. No governance structures are necessary for this new ownership model. It is entirely within the domain of energy consumers to purchase standalone systems for their use as they see fit and to disconnect from the grid if they no longer see any drawbacks in doing so.

- **Are there any additional legal considerations for this new ownership model?**

Other than the major legal considerations outlined above, any additional legal considerations will be included in Task 1.3.2.

10.4 Conclusion

The grid defection, in some respects, is the easiest model to achieve, since it relies on little changes to the status quo, aside from a continuing decline in solar and storage costs that make grid defection increasingly economical. However, it is also unique in that it is the one model that would have tangible and harmful results on many consumers, particularly lower-income households. Over the long-term, it is unlikely that the grid defection model would be able to maintain a high quality of service, or meet the State energy goals, due to significant declines in utility revenue for any necessary investments.

Figure 9. Grid Defection: Feasibility Criteria Summary

Criteria	Categorization	Various Considerations
Technical feasibility	Implications for the role and responsibilities of the utility	(-) Undermines role of the utility
	Assumption of utility responsibilities	(-) Unable to comply with reliability, adequacy, quality of service
	Achievement of State clean energy goals	(-) Unable to achieve clean energy goals
Financial feasibility	Impacts on ratepayers	(-) Significant costs to lower income households (-) Rising electricity grid costs
	Cost factors for initial acquisition	Not applicable
	Cost factors for achieving State clean energy goals	(-) Reduces revenue for investing into clean energy
Legal feasibility	Existence of supporting framework	(+) No significant legal impediments
	Governance requirements	(+) Minimal governance concerns
	Additional legal factors	Not applicable

11 Conclusion

From this preliminary analysis, we observed several key insights regarding the feasibility of each of the ownership models outlined above.

- **Conclusions on the feasibility of ownership models cannot be separated from accompanying regulatory reforms, particularly when determining if the new ownership model can achieve the State's clean energy goals.** All the ownership models – except perhaps for grid defection – can achieve the State's clean energy goals, provided that the appropriate regulatory policies are in place.

  Some of these ownership changes *require* regulatory changes. Examples include the SB and IDER models, which both require some form of deregulation in energy generation. Absent those changes, those models would not function as intended.

- **The "friendliness" of the acquisition plays a significant role in the feasibility of ownership models in which a new entity acquires the incumbent utility.** In some models such as the new owner or the co-op models, a friendly acquisition is potentially a necessary condition for the feasibility of the transition. In other ownership models, such as the muni and the hybrid model, while there are methods for a "hostile" acquisition, they are likely to significantly escalate acquisition and transaction costs that are likely to be passed onto consumers. The IDER and SB models can be mandated through regulatory reforms.

- **Strong leadership is necessary to meet the State's long-term goals**. Regardless of the ownership model, strong political, regulatory, and utility leadership will likely be necessary because of the scale of the change in the energy mix that will take place to meet the 2045 goals. This determination was supported consistently throughout the stakeholder engagement conducted as a part of this study. Some of these models require Hawaii state legislative action (hybrid), or local county action (munis), or ambitious reforms by the PUC (single buyer, IDER) while others can be undertaken by the utility alone (i.e., B-Corp). Each of these forums for action will have their unique political and institutional challenges to implementation.

  This need for leadership does not simply end with the acquisition of the utility. For some of the models that have greater stakeholder control and involvement, leadership is necessary to ensure a long-term focus on achieving the State's clean energy goals.

- **Maintaining a capable workforce is a significant concern for most ownership models**. Most of these models, except the new IOU owner model, have possible implications for hiring and maintaining a capable workforce that can ensure that the utility meets the standards of the PUC. Some of these concerns revolve around legal restrictions on employment (i.e., civil service restrictions in the muni and potentially hybrid ownership

models), management and salaries (i.e., the co-op model), or potentially requiring entirely new capabilities and expertise (SB and IDER).

While some of these concerns can be addressed by a thorough transition plan, the long-term necessity for qualified personnel remains a pressing priority for most of the ownership models.

For a comprehensive summary of findings, see Appendix A for Generation and Wires-focused models.

12 Appendix A: Generation-Focused and Wires-Focused Models Assessment

Figure 10. Comprehensive Feasibility Assessment (1/2)

	Criteria	New Owner	Hybrid	Muni	Co-op
Technical Feasibility	Implications for the role and responsibilities of the utility	(+/-) No significant changes	(+/-) No significant changes	(+/-) No significant changes	(+/-) No significant changes
	Assumption of utility responsibilities	(+) Access to in-house staff and expertise	(+/-) No significant changes	(+) Attractiveness of munis as employers	(+) Access to support networks
				(+) Integration with local government	(-) Possible disruption of the workforce
				(-) Possible disruption of workforce, but solutions possible	
	Achievement of State clean energy goals	(+/-) Subject to proposed transaction	(+/-) Subject to short-term decision-making	(+/-) Subject to implementation and context	(+/-) Subject to implementation and context
		(+/-) Subject to regulation	(+) Increased local control	(+) Potential innovation due to lack of PUC regulation	(+/-) Possibility of increased innovation (subject to PUC)
		(-) Possibly incompatible business models	(-) Misalignment of incentives and risk allocation	(+) Increased responsiveness to local stakeholders	(+) Increased responsiveness to local stakeholders
		(-) Subject to shareholder control, not local stakeholders	(-) Perception of inefficient and poor management	(-) Perception of inefficient and poor management	
		New Owner	**Hybrid**	**Muni**	**Co-op**
Financial Feasibility	Impacts on ratepayers	(+) Rate moratoriums, freezes, or credits	(+/-) Subject to local priorities	(+/-) Subject to the "friendliness" of transaction	(+/-) Subject to local priorities
		(+/-) Potential financial impact of unregulated businesses	(+/-) Subject to government management	(+/-) Subject to local priorities	(+/-) Regulation by PUC
		(-) For profit company with shareholder profit	(-) Increased public debt	(-) Increased public debt	(+) Capital credits returned to customer-owners
	Cost factors for initial acquisition	(+/-) Subject to the proposed transaction	(+/-) Subject to the "friendliness" of transaction	(+/-) Subject to the "friendliness" of transaction	(+) Access to low-cost debt
			(+) Strong Hawaii credit rating	(+) Strong county credit ratings	
			(-) Potential limits on bond issuance	(-) Potential limits on bond issuance	
	Cost factors for achieving State clean energy goals	(+/-) Subject to the proposed transaction	(+) Financing "halo" effect	(+) Tax-exempt financing	(+) Access to low-cost debt
		(+/-) Broad access to capital, but not necessarily an increase			
		(+/-) Possible increase in credit rating of utility			
		New Owner	**Hybrid**	**Muni**	**Co-op**
Legal Feasibility	Existence of supporting framework	(+) Preexisting legal framework, although past decisions do not necessarily establish precedent	(-) Requires legislative chartering of a holding corporation	(+/-) Variety of legal acquisition pathways	(+) Pre-existing legal framework
			(-) Requires substantial legislative bond issuance	(-) Requires county or referendum vote	
			(+/-) Unclear legal outlook		
	Governance requirements	(+) General IOU governance structure unchanged	(+/-) Subject to determination of public/private role	(+/-) Subject to context and goals	(+/-) Local governance through elections
		(+/-) Potentially subject to PUC determination	(+/-) Subject to independence of holding company		
	Additional legal factors	(+/-) Subject to PUC approval	(+/-) Subject to determination of civil service status for employees	(+/-) The status or relevance of PUC oversight	(-) 20,000 population cap on RUS funding
					(+/-) May or may not be subject to PUC regulation

Figure 10: Comprehensive Feasibility Assessment (2/2)

	Criteria	Single Buyer	IDER	Grid Defection
Technical Feasibility	Implications for the role and responsibilities of the utility	(+/-) Subject to realignment method (function unbundling, structural unbundling, independent entity)	(+/-) Separation of wires from generation	(-) Undermines role of the utility
			(-) Requires additional infrastructure	
	Assumption of utility responsibilities	(+/-) No significant changes	(+/-) Subject to implementation	(-) Unable to comply with reliability, adequacy, quality of service
	Achievement of State clean energy goals	(+) Realignment of utility incentives	(+/-) Subject to implementation	(-) Unable to achieve clean energy goals
		(+) Possible greater innovative flexibility	(+) Possibility of increased competition	
		(+) Possible procurement efficiency improvement	(+) Possibility of increased innovation	
			(+) Increased responsiveness to local stakeholders	
		Single Buyer	**IDER**	**Grid Defection**
Financial Feasibility	Impacts on ratepayers	(+/-) Dependent on procurement practices	(+/-) Insufficient empirical data	(-) Significant costs to lower income households
			(+) Possible value streams from DERs	(-) Rising electricity grid costs
			(-) Increased price volatility	
	Cost factors for initial acquisition	(+/-) Subject to realignment method	(-) Startup costs (i.e. ISO-like institutions and infrastructure)	Not applicable
	Cost factors for achieving State clean energy goals	(+) Realignment of utility incentives	(+/-) Insufficient empirical data	(-) Reduces revenue for investing into clean energy
		Single Buyer	**IDER**	**Grid Defection**
Legal Feasibility	Existence of supporting framework	(+/-) Existing framework, but requires significant additional regulatory or legislative reform	(-) Requires significant regulatory changes	(+) No significant legal impediments
	Governance requirements	(+/-) Requires independence from political and generation interests	(+/-) Must address conflicts of interest	(+) Minimal governance concerns
	Additional legal factors	Not applicable	Not applicable	Not applicable

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13 Appendix B: B-Corp Model Requirements and Certifications

The following outlines the requirements and certifications for the B-Corp certification.

General Certification Requirements

Corporations seeking the B Corp certification must receive at least 80 of 200 available points on the B Impact Assessment and review process. The assessment has two components:

1) **Business Model Review:** a company's business model is evaluated for on its intention and ability to solve social and/or environmental problems.
2) **Comprehensive Stakeholder Impact:** a company's comprehensive impact on its stakeholders is evaluated on the topics of Governance, Workers, Community, and Environment.

Companies that score above 80 on the initial B Impact Assessment must undergo a review and provide additional documentation to receive the certification. Companies must also integrate stakeholder commitments into legal governance documents to receive the certification.

Special Certification Requirements for Energy Providers

To obtain a B Corp Certification, an energy provider must be a for-profit corporation, so utilities owned by municipal governments, non-profit organizations, or cooperatives are not eligible for the certification. In addition to adjusting question and category weightings for the energy sector, The B Impact Assessment measures positive impact for energy providers by evaluating the energy resource mix offered to its customers. Up to 30 points are awarded for resource mix by generation percentage according to the following categories:

- **Full Credit** is awarded for renewable energy sources that have low environmental impacts, such as solar, wind, and small-scale hydroelectric electricity. To meet this requirement, the energy must meet standards set by the Green E-Certification.
- **Partial Credit** is awarded for environmentally preferred alternatives to conventional fuel sources, including low-emitting fossil fuel based energy and renewable energy that is not low-impact certified.
- **Zero Credit** is awarded for all energy sources that are neither clean or low-impact, such as coal, nuclear, and other conventional fossil-fuel based energy sources.

In addition to the resource mix evaluation, the B Impact Assessment for energy providers reviews the corporation's business model and impact in the other stakeholder categories described above. Like all other companies, energy providers must score 80 or higher on the assessment.

B Corp Certification Implications for Energy Providers

While it is difficult to assess the specific implications for a community served by a B Corp Certified energy provider, as all companies differ, a few high-level implications are summarized below:

- **High integration of renewable resources.** B Corps that provide energy are scored based upon the energy resource mix, with credit awarded for renewable resources. This scoring

mechanism requires and incentivizes B Corp energy providers to integrate clean energy technologies into their resource mix.

- **Orientation to problem-solving with new energy systems.** To obtain a B Corp Certification, utilities must demonstrate a commitment to using their business to solve social and/or environmental problems. Energy providers that have this orientation are highly likely to be pioneer new energy technologies and systems that achieve community goals, including the integration of renewable resources, grid resiliency features, and reduced customer costs (see case study below).
- **Commitment to customers.** B Corp businesses must amend legal governance documents to describe the company's commitment to its stakeholders, including customers. This commitment enhances collaboration with, and problem-solving for energy customers.
- **High transparency.** Certified businesses must achieve high levels of public transparency.

Utility B Corp Case Study: Green Mountain Power

Green Mountain Power (GMP), a utility that serves approximately 250,000 residential and business customers in Vermont, first obtained the B Corp certification in 2014 and was recertified in 2017. GMP's mission is to become Vermont's Energy Company of the Future by embracing a new energy system that reduces costs, is environmentally and economically sustainable, and improves customer lives. The company promotes that it is actively moving away from traditional grid models to enhance resiliency, reliability, and renewable generation through microgrids, energy storage and other new technologies. GMP has also partnered with customers to offer products and services like E-Homes (integrated home energy management), home weatherization, and smart products such as heat pumps and home batteries that help Vermont residents save money and reduce emissions.

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14 Appendix C: Scope of work to which this deliverable responds

Task 1.2.3. Summary and conclusions on the technical, financial and legal feasibility of each ownership model. CONTRACTOR shall provide a high-level assessment of the technical, financial and legal feasibility of each ownership model.

DELIVERABLE FOR TASK 1.2.3. CONTRACTOR shall provide its conclusions and all work to support a summary and conclusions on the technical, financial and legal feasibility of each ownership model. CONTRACTOR shall provide a written narrative in MS Word and spreadsheets in MS Excel. CONTRACTOR shall submit deliverable for TASK 1.2.3 to the STATE for approval.

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Stakeholder Workshop Summary: Utility Ownership Models

Prepared for DBEDT by London Economics International LLC and Meister Consultants Group, a Cadmus Company

December 18, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group, a Cadmus Company ("MCG"), was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals; this document is one of several working papers associated with that engagement. This draft Stakeholder Engagement Plan for the Utility Ownership Stakeholder Workshops is responsive to Task 1.2.4. which includes the preparation of an outreach plan to solicit public input from each island currently served by an electric utility on the results of Tasks 1.1.1. through 1.2.3., as well as a report that documents the results of the Stakeholder Outreach. This memo provides a summary of the stakeholder workshop conducted on October 9 to 11, 2017 on the islands of Hawaii, Kauai, Lanai, Maui, Molokai, and Oahu.

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List of Acronyms

B-corp	B-corporation
Co-op	Cooperative
DBEDT	Department of Business, Economic Development & Tourism
HECO	Hawaiian Electric Company
HEI	Hawaiian Electric Industries
HELCO	Hawaii Electric Light Company
IDER	Integrated Distributed Energy Resources
IOU	Investor-Owned Utility
IPP	Independent Power Producer
ISO	Independent System Operator
KIUC	Kauai Island Utility Cooperative
MECO	Maui Electric Company
Muni	Municipal Utility
OTEC	Ocean Thermal Energy Conversion
PPA	Power Purchase Agreement
PUC	Public Utilities Commission
PV	Photovoltaics
R&D	Research and Development

1 Executive Summary

1.1 Background

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. London Economics International LLC ("LEI") and Meister Consultants Group, a Cadmus Company ("MCG", collectively "the Project Team") were contracted to perform this study.

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria to:

- achieve state energy goals;
- maximize consumer cost savings;
- enable a competitive distributions system; and
- eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation.

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will aid in identifying the process to be followed to form such ownership and regulatory models and determining whether such models would create synergies in terms of:

- increasing local control over energy sources serving each county;
- ability to diversify energy resources;
- economic development;
- reducing greenhouse gas emissions;
- increasing system reliability and power quality; and
- lowering costs to all consumers.

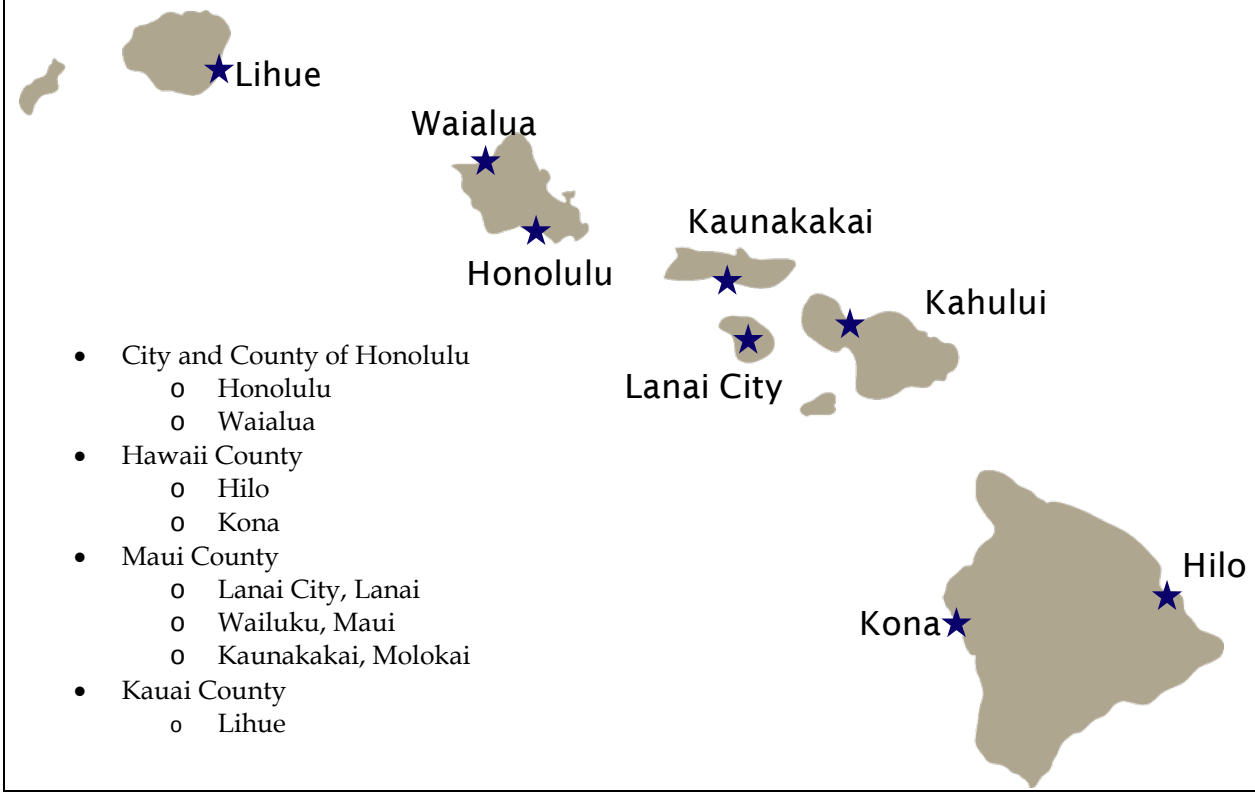
This report, Stakeholder Workshop Summary: Utility Ownership Models, has been prepared to fulfill requirements under Task 1.2.4 in the project scope of work and provides a summary of the stakeholder workshops conducted on each island during the week of October 9th, 2017.

The results from these workshops and the other stakeholder engagement conducted throughout this project will be incorporated into the analyses and the final report, to be submitted to DBEDT in October 2018. An e-mail address, DBEDT.UtilityBizModStudy@hawaii.gov, has been set up to collect feedback over the course of the project. All feedback related to the ownership model analysis that is received by November 13th, 2017 will be summarized and added as an addendum to this report. All other feedback will be incorporated into future reports submitted under this project.

1.2 Utility Ownership Model Stakeholder Workshops

The Stakeholder Workshops for the Utility Ownership Models were completed between October 9, 2017, and October 13, 2017. There were a total of eight (8) public workshops held, one at each of the locations shown in Figure 1.

Figure 1. Location of the meetings



- City and County of Honolulu
  - Honolulu
  - Waialua
- Hawaii County
  - Hilo
  - Kona
- Maui County
  - Lanai City, Lanai
  - Wailuku, Maui
  - Kaunakakai, Molokai
- Kauai County
  - Lihue

The objectives of the workshops were to provide stakeholders with information from the preliminary analysis of the ownership models, to receive their input on what they value in their utility, and to receive input on the advantages and disadvantages of different ownership models in meeting those values. Combined, 141 stakeholders participated in the public workshops.

In addition to the workshops, the Project Team conducted multiple bilateral meetings as part of the ongoing stakeholder engagement process throughout the entirety of this project. The Project Team met with 20 energy industry, government, and other stakeholders from across the state and received input that varied from the importance of leadership (with the utility and the Hawaii Public Utilities Commission), to the technological opportunities for addressing specific needs (e.g. microgrids and resiliency), to the value of local influence on decisions, to the need for innovation and nimbleness to address the state's needs.

1.3 Key findings from workshops

While the discussions at each workshop were unique, there were some common themes that arose, including:

- reliable electricity is a priority, and any impact that a different model may have on this must be considered;
- keeping rates as low as possible now and in the future, is a priority;
- stakeholders place a high value on the ability to be engaged in and influence utility decisions to ensure they are aligned with community needs, whether this be through local ownership opportunities or formal processes for engagement;
- investing in grid improvements, not just to meet the 100% clean energy goals, but to ensure reliability and resiliency, especially in preparing for severe weather;
- a demand for more renewable energy, from more diverse sources, and for more opportunity for customer-sited generation;
- importance placed on innovation and strong leadership as integral components necessary for the utility to be successful, regardless of ownership model;
- many stakeholders view competition as the best option for driving efficiencies and keeping rates low; and
- many stakeholders are concerned that equity, in terms of cost of electricity and access to the benefits of renewables, is not being considered sufficiently.

At each workshop, stakeholders had the opportunity to discuss various ownership models:

1.3.1 IOU

In general, stakeholders expressed that IOUs were typically stable, benefitted from economies of scale, and had the ability to attract a talented workforce. There was a concern, however, about a lack of competition and a misalignment between utility incentives and community or policy priorities. Stakeholders often expressed concern that IOUs are driven primarily by increasing shareholder profit and that they are not innovative in adopting new technologies. Some stakeholders were interested in how what they saw as a misalignment of interests could be addressed through regulatory approaches, or through the adoption of new investor-owned utility models, such as B-corporation (B-corp).

1.3.2 Munis

While stakeholders considered munis to be more responsive to community interests, there was little interest in this model as a viable option due to worries about politicization and inefficiencies that may result from a government running a utility. Many groups also questioned if their county government would have the resources or interest in purchasing and operating the utility.

1.3.3 Co-op

Many stakeholders mentioned KIUC and its successes and discussed if this model would be a good path for their community to increase renewable generation, reduce rates, and better incorporate community values. Numerous stakeholders expressed a general interest in the cooperative model on every island in the co-op model, particularly because it allows the community to have a direct influence on the decision-making process. This interest was limited in particular on Oahu, however, where it was felt that the population and complexity of The City and County of Honolulu may be too great for a cooperative. Stakeholders expressed an interest

in the cooperative model, particularly on Kauai, where KIUC currently operates a cooperative utility, and on the Big Island, where a legal entity has been established for the purpose of operating a potential future cooperative utility. Some stakeholders felt that it could be challenging to engage enough citizens to be active participants in a co-op and noted that the process could be frustrating, but they also felt that the co-op model could allow for more innovation and better serve the needs of citizens.

1.3.4 Wires-only (Single Buyer and integrated distributed energy resource ("IDER") models)

At the workshops where wires-only utilities were discussed by the stakeholders, there was interest in better understanding the options and the opportunity they could provide for engendering competition, with a particular interest in ISO and IDER models. Some stakeholders felt that a wire-only model would reduce rates, increase renewable deployment, and encourage innovation by creating competition in the generation sector. Specifically, several stakeholders expressed that a wires-only model could create more opportunities for renewable energy development, and the formation of new energy business models. Stakeholders also noted the complexity that would come with the formation of such a model.

In general discussions, some stakeholders felt that a change in ownership model may not address their community's priorities and expressed interest in understanding how regulatory changes could incentivize utilities to align their actions with community goals. When discussing a theoretical change in ownership, many stakeholders highlighted that the transition costs would be too high to bear without a willing seller.

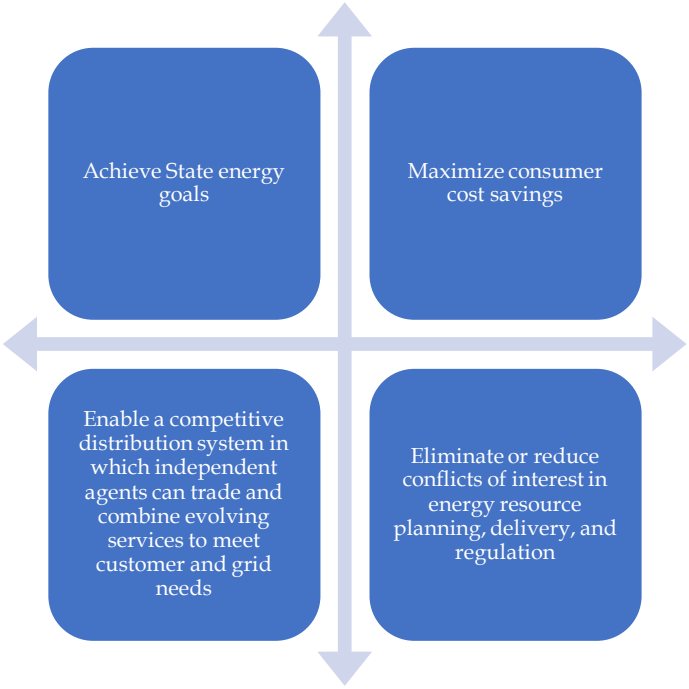
2 Introduction and scope

2.1 Project description

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. LEI and MCG, through a competitive sealed proposals procurement,[1] was contracted to perform this study.[2]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[3] listed in Figure 2.

Figure 2. State's key criteria



Source: Scope of Services under Contract No. 65595

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models and determining whether such models would create synergies in terms of

[1] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[2] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[3] House Bill No. 1700 Relating to the State Budget.

increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[4]

2.2 Role of this deliverable relative to others in the project

This deliverable has been prepared to fulfill requirements under Task 1.2.4 in the project scope of work. Task 1.2.4 requires us to prepare a report documenting the public outreach. Comments received from the workshops will be analyzed and considered as we conduct the other tasks under this project, namely:

- Task 1.2.5. - Ranking process and rationale for recommendation of three feasible utility ownership models;
- Task 1.3.1. - Identification of various steps, timeline, and costs required to change from current ownership model to new models, including regulatory approvals;
- Task 1.3.3. Identification of risk for each ownership model, analysis of each risk, and assessment of the overall risk profile for each ownership option; and
- Task 1.6.5. - Qualitative assessment of financing options for each ownership model.

[4] Hawaii Contract No. 65595. Scope of Services.

3 Stakeholder Engagement Overview

3.1 Objectives

Throughout the project, the team is meeting with stakeholders representing interests across the economy from each island to both receive their input on what the utilities' role is in achieving state policy goals and to provide interim and final results of the analyses. The broad objectives are to:

- introduce the public to this project and provide multiple pathways for public input;
- provide information to support the public's understanding of the differences between and trade-offs of multiple utility ownership and regulatory models; and
- provide information on possible approaches for Hawaii to best achieve the state's clean energy and other policy goals.

There are two groups of stakeholders: the Core Group and the Public Group. The team convened a Core Group of stakeholders including representatives from the organizations listed below on September 22, 2017, and October 13, 2017.

Figure 3. Core Group

Public Sector	County Energy Coordinators	County Economic Development Boards	Utilities
o DBEDT o Consumer Advocate o Public Utilities Commission ("PUC")	• Hawaii • Honolulu • Maui • Kauai	• Hawaii • Honolulu • Maui • Kauai	o Hawaiian Electric Company ("HECO") o Hawaiian Electric Light Company ("HELCO") o Kauai Island Utility Cooperative ("KIUC") o Maui Electric Company ("MECO")

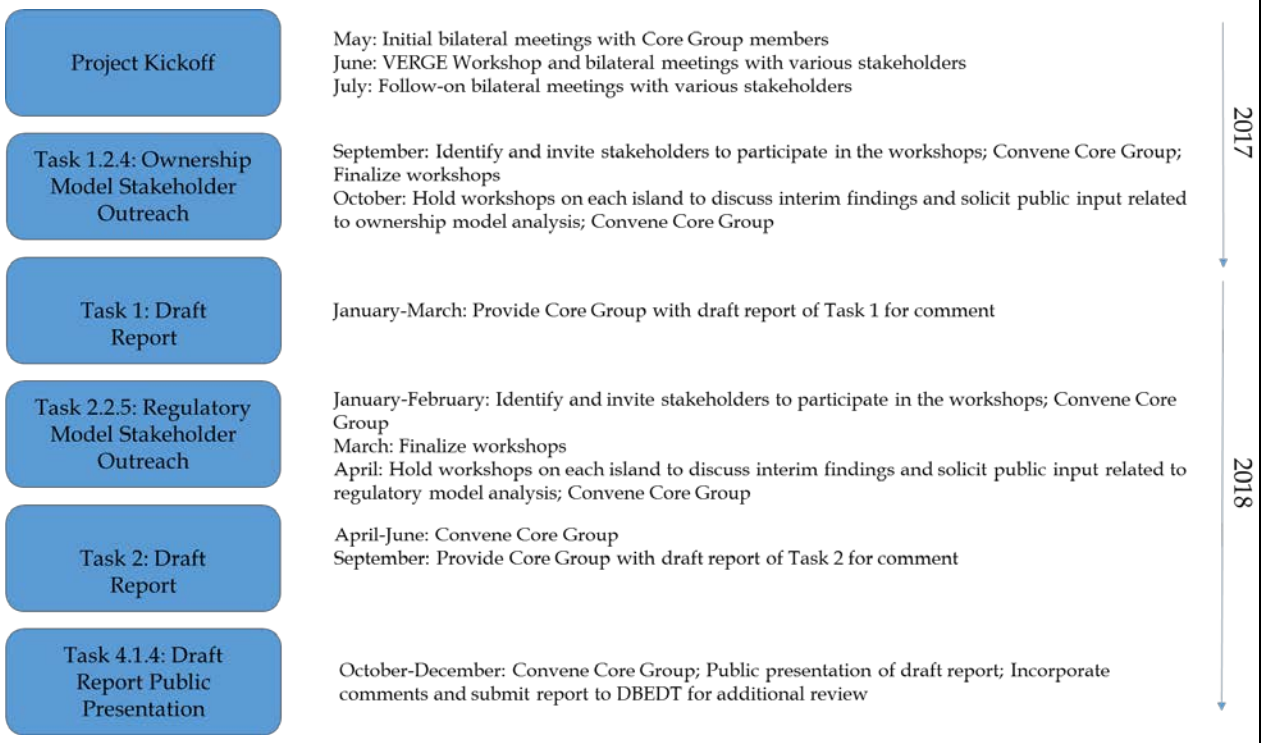
The team will continue to engage with the Core Group throughout the project to solicit their input on the process for stakeholder engagement, the stakeholders with whom to meet and to comment on interim and final analyses. These meetings will take the form of a conference call, to be coordinated and scheduled by the Project Team. The proposed timing for convening the Core Group is outlined in Figure 3 below.

The Public Group is open to any parties interested in this project's scope. Therefore, the Public Group will include representatives from the general public, state and county institutions, non-profits, the private sector, academia, and the federal government (primarily the U.S. Department of Defense and U.S. Department of Energy).

3.2 Timeline

Over the span of the project, the team will actively engage with stakeholders at multiple points and will be open to additional discussions as requested by stakeholders. The following is a high-level timeline of the stakeholder engagement opportunities that are currently planned, broken out by task (Figure 3). While target months are provided for all activities, these are subject to change as the timeline of the broader project evolves, particularly the 2018 dates.

Figure 4. Indicative Timeline for Stakeholder Engagement



4 Stakeholder Engagement: Utility Ownership Model

For Task 1.2.4, the team conducted stakeholder workshops on each island served by an electric utility. The Stakeholder Outreach Plan, which was submitted on August 9, 2017, provided a detailed discussion of the stakeholder engagement process conducted for this task. This section provides a summary of the process and documentation of the discussions on each island.

4.1 Objective and Scope

The primary objectives of the Utility Ownership workshops were to:

- solicit public input on the topic of utility ownership models from stakeholders on each island;
- create opportunities for everyone to share his/her opinion on Hawaii's utility ownership models;
- provide a high-level overview of the project's mid-deliverable findings (Tasks 1.1.1-1.2.3) including a discussion of the different ownership models identified by the Project Team;
- provide clear, easy to understand and objective information on the differences between utility ownership models;
- provide an overview of the difference between ownership and regulatory models and the types of issues that can be addressed by ownership models; and,
- provide clear information on the next steps that the team will be taking and future opportunities for stakeholders to participate or provide feedback.

The Project Team anticipated that the participants would have a varied knowledge of the energy sector and utility ownership models, ranging from the general public with a more basic understanding of the sector to experts in the field. As such, the public workshops were designed to be high level and focus on building a common understanding of definitions and terms, the trade-offs between different utility ownership models, and developing an understanding of what the community sees as the role of the utility, based on the analysis conducted for this project.

Additionally, the number of participants was expected to vary greatly by island. As such, the breakout sessions were designed and selected based on approaches that work well for the number of participants at each workshop.

4.2 Administration of Workshops

4.2.1 Workshop Administration

The workshops were administered and facilitated by the Project Team members, with one Project Team member designated as the lead facilitator. The DBEDT representatives provided welcoming and concluding remarks, and otherwise observed or responded to questions as needed. There were three Project Team members at each public workshop, with the exception of the Honolulu workshop where four Project Team members facilitated the discussions as a larger group was expected. The workshops were completed over a one week period, divided among two teams of facilitators:

Team 1:

- Lead Facilitator: Julie Curti
- Facilitator: Ryan Cook
- Facilitator: Gabriel Roumy

Team 2:

- Lead facilitator: Christina Becker-Birck
- Facilitator: Sarah Booth
- Facilitator: Len Trinidad

4.2.2 Workshop Agenda

Each workshop was scheduled for 5:30 pm – 7:00 pm, with the exception of the Honolulu workshop which was scheduled for 6:00 pm – 7:30 pm. The workshop agenda is provided in Figure 5.

Figure 5. Workshop Agenda

Time	Topic Addressed	Overview
5:30pm to 5:35pm	Arrival time	• Time for participants to take their seats and allow for late arrivals • Invite participants to sign-in as they arrive
5:35pm to 5:40pm	Welcome, introductions, and icebreaker	• Project team welcomes the group and introduces themselves • Participants are invited to introduce themselves
5:40pm to 5:55pm	Presentation Part I and Q&A	• Share purpose of the workshop • Review ground rules for discussion • Utility overview presentation • Q&A as time allows
5:55pm to 6:15pm	Feedback on Stakeholder Priorities for their Utility	• Facilitated discussion to better understand stakeholder interests underlying their positions on ownership (e.g. more renewables, cost to customers, reliable electricity, etc.) • Questions: o What does your utility do well for you? For Hawaii? o What else do you want to see from your utility that you don't have now? For Hawaii? • Pin board discussion and summarize results by theme at close of discussion.
6:15pm to 6:30pm	Presentation Part II: Utility Ownership Models	• Presentation on different utility ownership types and models (e.g. IOU, muni, and co-op), as well as what utilities can own. • Q&A following the presentation as time allows.

Time	Topic Addressed	Overview
6:30pm to 6:55pm	Small Group Discussion	• Each table has a designated small group facilitator who provides context for the discussion by showing the worksheet with the evaluation chart. Goal is to work through each utility model and discuss benefits, disadvantages, opportunities in switching ownership, and challenges in switching.
		• Questions for discussion include:
		o What benefits do you see from each model?
		o What drawbacks do you see from each model?
		o What is accomplished by a change in utility ownership? Does it address your priorities?
		o What are the key challenges to changing to this utility ownership model?
6:55pm to 7:00pm	Lightning Report-outs and Closing	• Small group facilitators provide lighting report-outs on key takeaways from their discussion.
		• Project team shares next steps for projects and thanks participants for coming.
		• Invite further input and questions in one-on-one discussions with team members following the workshop and/or to submit comments to the email.
7:00pm to 7:30pm	Follow-on Discussions	• The project team will remain onsite to allow for any follow-on discussions as needed.

4.2.3 Materials Provided to Participants

All participants were provided with two handouts:

1. Utility Ownership Model Summary (Appendix A: Utility Ownership Model Summary Handouts), which provided an overview of the different aspects of utility ownership models being analyzed for this project; and

2. Discussion Matrix Worksheet (Appendix B: Discussion Matrix Worksheet), which listed the questions used in the facilitated, small-group discussions.

4.3 Workshop Content

4.3.1 Team Presentations

The Project Team provided overview slides that were used all, or in part, at all meetings except those on Molokai and Lanai based on the expectation of fewer attendees.[5] At those two locations, the Project Team covered the same material in an open discussion format while walking through the summary handout to highlight the main points from the slides. The slides, which are included in Appendix C: Presentation Slides, provided:

- an overview of the project;
- a discussion of the role of the utility and PUC;
- the landscape of utilities operating in Hawaii;

[5] There were more participants than anticipated at the Lanai workshop.

- the different aspects of utility ownership models being analyzed for this project; and
- information on future opportunities for stakeholders to participate and provide input.

4.3.2 Format for Stakeholder Discussions

There were two main sections of the workshop focused on stakeholder discussions (see Table 1):

1. Feedback on Stakeholder Priorities for their Utility
2. Small Group Discussion

The Feedback Discussion was facilitated by the team's lead facilitator who asked the participants to talk about what their utility does well.[6] The comments were written down on note cards and arranged thematically, either on a pinboard or table. The facilitator then asked the participants to discuss what else they would want to see from their utility. The comments were written down on note cards and arranged thematically, either on a pinboard or table.

The Small Group Discussion focused on discussing the benefits and drawbacks of the various ownership models, as well as the challenges to transitioning to each ownership model. For workshops with more than 10 participants, the participants broke into smaller groups for this discussion.[7] All discussions were facilitated by a Project Team member to ensure the conversations stayed productive and relevant, and that all participants were given the opportunity to speak if they desired to do so.

4.4 Stakeholder Workshop Schedule

Table 2 lists the date, location, and venue of each of the stakeholder workshops. Team 1 held two meetings on Hawaii and two on Oahu. Team 2 held one meeting on Maui, Molokai, Lanai, and Kauai, and joined Team 1 for the meeting in Honolulu.

[6] For the meeting in Honolulu, the participants broke out into three smaller groups for the Feedback Discussion with a facilitator at each table. At all other meetings, all participants worked through this exercise together.

[7] The number of small group breakouts was determined based on the number of participants. For Molokai and Waialua, there was one group discussion; for Hilo, Kona, Lanai, and Maui, there were two small groups; and for Kauai and Honolulu, there were three small groups.

Figure 6. Stakeholder Workshop Schedule

Team 1			
	Island	**Town**	**Venue**
9-Oct	Hawaii	Kona	Natural Energy Laboratory of Hawaii Authority
10-Oct	Hawaii	Hilo	Waiakea High School
11-Oct	Oahu	Waialua	Waialua High & Intermediate School
12-Oct	Oahu	Honolulu	*No Workshop - Bilateral Meetings Only*
13-Oct	Oahu	Honolulu	Hawaiian Foreign Trade Zone

Team 2			
	Island	**Town**	**Venue**
9-Oct	Maui	Wailuku	Wailuku Community Center
10-Oct	Molokai	Kaunakakai	Mitchell Pauole Main Hall
11-Oct	Lanai	Lanai City	Lanai Community Center
12-Oct	Kauai	Lihue	Chiefess Kamakahelei Middle School
13-Oct	Oahu	Honolulu	Hawaiian Foreign Trade Zone

4.5 Outreach for Stakeholder Workshops

To announce the workshops and invite stakeholders, the Project Team conducted outreach through four primary channels[8]:

1. Press release to media contacts
2. Email invitation to stakeholders
3. Discussion with the Core Group
4. Outreach through the HSEO website and social media outlets

The Project Team prepared flyers and a press release to announce the workshops (Appendix D: Outreach Flyers). The press release, which summarized the goals of the workshop, provided logistical information, and linked to the flyers, was sent out to the organizations listed in Figure 7 on September 29, 2017:

[8] The workshop dates and venues were approved in early October. In addition to the Project Team's outreach, DBEDT publicized the workshop with a press release posted on October 5th at http://dbedt.hawaii.gov/blog/17-55/.

Figure 7. Media Outlets

Island	Business or Organization
Print, Online Media, and Local Business Groups	
Hawaii	Big Island News
	Hawaii 24/7
	Hawaii Island Chamber of Commerce
	Hawaii Tribune Herald
	Ililani Media
	Konaweb Community Calendar
	Leeward Planning Conference (calendar)
	Rotary Club of Kona
	Rotary Club of Kona Mauka
	Rotary Club of Kona Sunrise
	Rotary Club of North Hawaii
	Rotary Club of Pahoa Sunset
	Rotary Club of South Hilo
	Rotary Club of Volcano
	Rotary Club of Hilo Bay
	West Hawaii Today
Oahu	Civil Beat
	Green List Hawaii
	Hawaii Business
	Hawaii Chamber of Commerce
	Hawaii Free Press (Statewide)
	Hawaii Midweek Calendar (Statewide)
	Hawaii Public Radio Events Calendar (Statewide)
	Honolulu Star Advertiser (Statewide)
	Kailua Chamber of Commerce
	Midweek Oahu
	Northshore Community Calendar (Chamber of Commerce)
	Northshore News
	Pacific Business Journal (Statewide)
	Rotary Club of Hawaii Kai
	Rotary Club of Honolulu
	Rotary Club of Kahala Sunrise
	Rotary Club of Kapolei Sunset

Island	Business or Organization
Print, Online Media, and Local Business Groups	
Maui	Calendar Maui
	Maui Chamber of Commerce
	Maui Now
	Rotary Club of Kahului
	Rotary Club of Kihei-Wailea
	Rotary Club of Lahaina
	Rotary Club of Maui
	Rotary Club of Upcountry Maui
	Rotary Club of Wailuku
	The Maui News
Molokai	Molokai Chamber of Commerce
	The Molokai Dispatch
Lanai	Lanai 96763
	Lanai Chamber of Commerce
	Lanai Today
Kauai	Kauai Chamber of Commerce
	Kauai Event Calendar
	Kauai Midweek
	Rotary Club of Hanalei Bay
	Rotary Club of Poipu Beach
	The Garden Island Newspaper
	Radio
Oahu/Statewide	Hawaii Public Radio
Maui	KAKU
	KAOI
Kauai	Core Group sent to local stations
Hawaii	Multiple Stations[1]

Note: [1] A community member shared the information via the community calendars used by multiple radio stations.

Email invitations were sent to more than 1,000 stakeholders beginning on September 29, 2017 (Appendix F: Email Invitation Text). The stakeholders that received email invitations were identified in discussion with DBEDT, the Core Group, bilateral meetings with stakeholders in Hawaii, through interactions at VERGE, and through HCEI. The invitations provided a summary of the workshop goals and a link to the flyers where participants could sign-up for the event. DBEDT called 46 elected officials, including congressional delegates, county council members, and members of the energy and consumer protection committees in the State House and Senate.

During the Core Group call on September 22, 2017, the Project Team provided the members with the logistics for the meetings on each island and requested that they share the information with

their contacts and networks as appropriate. Some members of this group shared the information directly with contacts or through social media accounts.

4.6 Workshop Participants

The workshops were attended by stakeholders representing county organizations, state organizations, utilities, non-profits/community groups, academia, local and state elected officials, and the private sector. There was a total of 141 participants at the 8 stakeholder workshops (see Figure 7 and Figure 8 for details by workshop). Stakeholders that were unable to attend have been encouraged to submit feedback to dbedt.utilitybizmodstudy@hawaii.gov. Feedback will be collected over the course of the project.[9] At the county level, participation ranged from 27 in Kauai County to 45 in Maui County. The workshop in Honolulu had the highest attendance at 29 and Waialua had the fewest attendees at 6. In total, the number of attendees exceeded the number of invitations sent.

Figure 8. Workshop Invitation and Participation

County (Town, Island)	Invitations Sent*	RSVPs**	Participants
City and County of Honolulu	**56**	**-**	**35**
Honolulu, Oahu	-	34	29
Waialua, Oahu	-	7	6
Hawaii County	**25**	**-**	**34**
Hilo, Hawaii	-	12	14
Kona, Hawaii	-	7	20
Kauai County (Lihue)	**19**	**17**	**27**
Maui County	**-**	**-**	**45**
Lanai City, Lanai	2	14	18
Wailuku, Maui	15	19	19
Kaunakakai, Molokai	3	7	8
Statewide Organizations	**6**	**-**	**-**
TOTAL	**126**	**117**	**141**

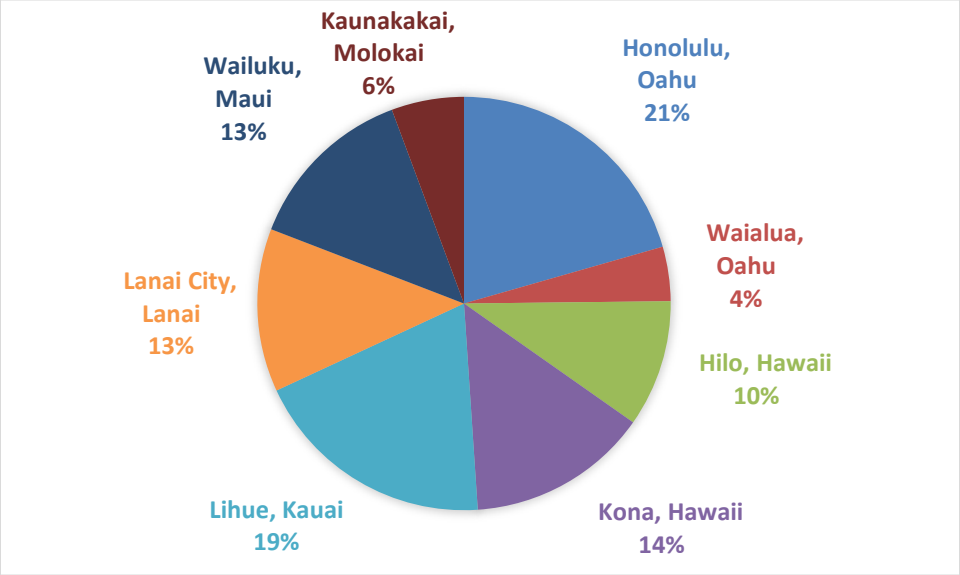
Notes:

** Invitations were sent on an island basis, not to specific stakeholders for each town.*

*** RSVPs were tracked for each meeting location.*

[9] Feedback received at this email address is not included in this report. Feedback received through November 13th will be summarized in an addendum to this report. Feedback received after November 13th will be incorporated into future reports for this project.

Figure 9. Percentage of Total Participants at each Workshop



5 Stakeholder Discussions

A large portion of each workshop focused on facilitated stakeholder discussions to receive input from participants on their priorities for an electric utility and the advantages and disadvantages of different ownership models in achieving the community's priorities. The following sections provide a summary of the discussions from each workshop. A high-level overview of the discussions is provided in Figure 10, Figure 11, Figure 12, and Figure 13. There were often differences of opinions among stakeholders at each workshop and Figure 8 is not meant to imply a consensus of the stakeholders present nor of the entire community.

Figure 10. Summary Table of Workshop Discussions: City and County of Honolulu

Location	Top Priorities	Discussion Highlights by Model			
		IOU	Muni	Co-op	Wires-Only
Honolulu	Local influence Innovation and flexibility Distributed renewables Affordable rates and increased equity	Not aligned with public interest but with shareholders' interest Lack of opportunities for stakeholder influence in decisions	Potential for politicization of utility operations Concern about operational inefficiencies	Allows for local control Could operate with less overhead Difficult to educate and encourage active consumers Might not work for population size and diversity on Oahu	Encourage more competition and distributed energy Require changes to the regulatory framework which could be difficult to get right
Waialua	Diverse energy generation, more renewables Resiliency Customer service Minimal bureaucracy	Stable leadership and reliable service Less competition for IPPs	Too political Equity concerns for rural areas	Allows for consumer input Difficult to ensure broad engagement Concerned about fit for Oahu	Very interested in this model Greater competition for generation Likely to lower costs

Figure 11. Summary Table of Workshop Discussions: Hawaii County

Location	Top Priorities	Discussion Highlights by Model			
		IOU	Muni	Co-op	Wires-Only
Hilo	Affordable rates and equitable access to renewables Innovation Local ownership Utility-scale solar	Good access to resources Less investment in renewables Profits go to off-island stakeholders High rates	Subject to political whims Little interest in model for Big Island	Supportive of this model Local input in decision making Requires engaged members and education	Did not discuss in detail
Kona	Reliable service Renewable energy Lower rates Agile, innovative utility	Not aligned with community priorities Not as responsive to customer needs Lack of innovation Lack of local control	Subject to political whims Concerned about fit for Big Island, partially because of geographical diversity	Alignment between local priorities and utility priorities Lower rates Reduced resources to deal with disaster recovery Might not be a good fit because of geographical diversity and size of population	Interest in the IDER model Separation of generation and T&D beneficial Increase distributed renewables and microgrids

Figure 12. Summary Table of Workshop Discussions: Kauai County

Location	Top Priorities	Discussion Highlights by Model			
		IOU	Muni	Co-op	Wires-Only
Lihue	Local control Efficient use of resources Energy education (members and board)	Lack of local control No incentive to reduce expenses Incentivized to increase capital investments Lack of interest in this model	Local influence on decisions Influenced by politics Inefficient use of resources Concerned about fit for Kauai	Works well for Kauai Democratically controlled Efficient use of resources Access to resources through co-op networks Low-cost financing options PUC regulation hinders operations	Did not discuss in detail

Figure 13. Summary Table of Workshop Discussions: Maui County

Location	Top Priorities	Discussion Highlights by Model			
		IOU	Muni	Co-op	Wires-Only
Lanai	Reliable, affordable electricity Local influence Responsiveness to community needs Planning for 100% renewables	Economies of scale Lack of local control and incorporating community needs	Accountable to community Lower rates; not profit driven Political influence and inefficient Lack of interest in this model	Local control Nimble Staff necessary to operate may not be available on island High cost to maintain grid	Did not discuss in detail
Maui	Local influence Reliable service Diverse fuel mix, more renewables, more distributed renewables Innovation Resiliency	Attract talented workforce Profit motive can drive efficiencies HECO Companies share resources Off-island ownership makes it more difficult to regulate Interest in B-corp model	Political influence County may lack the expertise to operate efficiently High cost to county to purchase a utility	Local influence; incorporation of community needs Requires engaged and informed members, which could be difficult Can be short-sighted if board members focused on reelection Questioned if Maui qualified for rural financing	Separation of generation and T&D creates competition and lower rates Forces utility to be more flexible Interest in ISO

Location	Top Priorities	Discussion Highlights by Model			
		IOU	Muni	Co-op	Wires-Only
Molokai	Safe and reliable service Local influence Transparency Equity Diverse energy mix	Distrust of IOU leadership Lack of local influence Access to private capital beneficial Interested in B-corp model	Political influence Inefficient operations Questioned fit for Molokai	Local input in decisions Trust board because from community Efficient use of resources Starting a co-op difficult Interest in hybrid co-op/IOU model to better incorporate community needs	Did not discuss in detail

5.1.1 The City and County of Honolulu

Two meetings were held in the City and County of Honolulu, one in Waialua and one in Honolulu.

5.1.1.1 Honolulu

The workshop was held in the Homer A. Maxey International Trade Resource Center Conference Room at the Hawaii Foreign-Trade Zone #9 in Honolulu. There were 29 participants.

5.1.1.1.1 Priorities for Stakeholders

The stakeholders discussed a number of priorities for their utility, with three primary topics being mentioned multiple times, including:

- providing more opportunity for productive stakeholder engagement in the decision-making process and better aligning utility operations with the public interest;
- focusing on innovative solutions and transforming the utility to operate flexibly and nimbly in the new environment where renewable energy, particularly distributed energy resources, contribute substantially to the grid; and
- reducing the cost of energy, improving equity in rates, and improving access to renewables for lower-income customers.

In coordination with opportunities for stakeholder engagement, the participants pointed to the important role that a utility plays in providing education to the community (e.g., technical constraints, operation costs) and the value of transparency in their operations. When stakeholders are knowledgeable of the utility's operations, they can better participate in stakeholder engagement processes and have more productive input for the utility. When utilities improve their stakeholder engagement process and incorporate input, they are more likely to align their operations and investments with the public interest. However, many in the group discussed that providing accurate but simple information to consumers can be difficult.

Stakeholders indicated that strong leadership was valued as a necessary component for a utility to be successful in planning for and investing in innovative technologies in the short- and long-term.

Many stakeholders would like to eliminate any bias toward utility ownership of assets and for the utility to be supportive of distributed energy resources. The need for more utility-scale renewable energy generation was raised as well as a strong interest in more renewable energy on the grid. Cost management was a high priority with one stakeholder suggesting internal audits be conducted to ensure the utility is operating efficiently as possible.

Stakeholders also raised equity as a concern. Equity was raised in relation to ensuring that low-income customers have access to renewable energy and ensuring costs do not rise too high as wealthier consumers leave the grid and the costs to maintain the infrastructure are spread across fewer ratepayers. Improved rate design was suggested as a solution as well. Stakeholders also raised concerns about the cost of energy for all customers.

The stakeholders highlighted the following areas where HECO performs well:

- Provides reliable electricity (arose many times)
- Responds quickly to address outages
- Open to innovated solutions
- Manages billing
- Locally owned
- Provides a good return to shareholders
- Provides information to consumers about renewables
- Invests in infrastructure for new development
- Hard-working and friendly employees
- Is a major employer of skilled workers in the community
- Tries to keep rates as low as possible

5.1.1.1.2 IOU

In general, the majority of stakeholders felt that an IOU's operations do not align with the public interest and that they are most responsive to investors interested in a high, stable rate of return. However, some stakeholders also discussed how the "capitalistic incentives" inherent to an IOU could drive efficiencies because the utility is incentivized to optimize revenue. If regulations are designed correctly, one stakeholder suggested that the IOU can bear some of the investment risks which would encourage them to invest wisely while taking into account the community's priorities.

The primary drawback of this model as seen by the stakeholders was the lack of opportunity for community engagement and influence in decisions and that, instead of reflecting the community's needs, the decisions are made primarily with shareholders' interests in mind. IOUs were considered to be adverse and slow to change and not innovative, in part because they are regulated to reduce risk. Stakeholders discussed that the ratepayers own the investment risks because they are passed through by the utility. There was some concern that IOUs can have undue influence over regulatory bodies, making it difficult for regulatory bodies to remain unbiased. One stakeholder shared that it is important to consider the difference between a publicly traded IOU and one owned by private equity firms and that the latter could provide more flexibility to transform an IOU to better align with state goals.

In relation to a potential new company purchasing the incumbent utility, some stakeholders expressed that they would trust an outside company less than they do the HECO companies. Additionally, stakeholders highlighted that it would be important for any transition in ownership to ensure that there were benefits to the ratepayers.

5.1.1.1.3 Muni

Some stakeholders viewed munis as typically stable and inherently focused on long-term planning as a result of being incorporated in the local government. If structured to be somewhat segregated from other municipal government operations, munis were seen to have the potential to be very efficient. One stakeholder pointed to the potential benefit of using revenues from the utility to support broader community goals. Munis were considered to have access to cheap

capital. Additionally, stakeholders discussed how munis could have lower rates for customers since they are not driven by creating investor profits.

The stakeholders identified the primary disadvantage of this model as the potentially high politicization of decisions and control of the utility, which had the potential to conflate the provision of electric service with other, unrelated, policy priorities. This was raised as a strong concern. Additionally, many stakeholders considered the government to have a reputation for being inefficient and dysfunctional which raised many concerns about the government operating a utility. Some stakeholders also raised the concern of industry capture by politicians and that they could use rates as a pass-through for raising taxes on residents. This model was not considered to be particularly innovative or fast to change. Stakeholders also apprehensive about the lack of PUC oversight in this model.

5.1.1.1.4 Co-op

The primary benefit identified by stakeholders was the local control in the decision-making process which would allow for close alignment of utility activities with community goals. There was the expectation that this model could operate with less overhead designated to administration. Many stakeholders viewed KIUC as innovative and nimble, and the co-op model as the most responsive and customer-centric of the models.

Many stakeholders identified potential drawbacks to the co-op model for Oahu. First, they noted that an educated constituency is critical for informed decisions and providing the necessary education could be very difficult, particularly with a large population. There was concern that there could be a bias in the education provided to consumers based on the utility leadership's goals which would then influence the public without providing them with all of the information needed to make an informed decision in their best interest. Without sufficient education, some stakeholders worried that the utility control and decisions could become highly politicized and subject to new directions depending on the board.

For Oahu, the population and size raised concerns as to whether a co-op would work well on the island. For example, stakeholders expressed it could be difficult to fairly balance diverse customer needs and hard to explain this to members. It could also be difficult to encourage so many people to be engaged in the process. One stakeholder noted that it can be "exceedingly frustrating" to participate in a co-op, especially a large co-op, but that it often will yield better outcomes for customers than other ownership models. Stakeholders also noted a cooperative utility on Oahu would be particularly large based on the size of mainland utility electric cooperatives and questioned whether The City and County of Honolulu would qualify for rural designation (and the associated low-cost financing) by the federal government.

Finally, some stakeholders pointed out that the cost of capital for a co-op can be higher than with other models, while others noted the benefits of low-cost federal financing from the Rural Utilities Service. It was also mentioned that KIUC inherited a large debt which impacted rates. This view, however, differed from other stakeholders who pointed to lower-cost capital available to co-ops via the Rural Utility Service. These stakeholders also pointed to KIUC's rates becoming more stable while IOU rates were rising.

5.1.1.1.5 Wires-Only

There was interest from some stakeholders in exploring if a system operator/wires-only model would be a less expensive option to ensure the utility operates in a way that better meets the priorities identified above. In particular, several stakeholders expressed hope that a wires-only approach to utility ownership would enable the emergence of new distributed energy business models, and could provide opportunities for a peer-to-peer energy marketplace. It was noted that such an approach could be more suitable for Oahu compared to other islands given the relative size of the electric grid.

A significant concern raised regarding this ownership model was the need to change the state electric utility regulatory framework to ensure that the transmission and distribution system owner has a viable business model and is given adequate incentives to develop and maintain the grid infrastructure that will be needed to support such a competitive generation marketplace. Additionally, a strong regulatory approach would be needed to ensure that grid reliability, safety, and consumer protection standards are met. Stakeholders also expressed several concerns with a more competitive marketplace, including an equity concern that utility customers with capital resources would be best able to take advantage of new business models and opportunities, a fear that there may not be enough land or water area available to support a truly competitive generation system, and that there may be not-in-my-backyard challenges to building new generation sources that could stymie competition.

5.1.1.1.6 Other

There were some themes discussed that apply regardless of the ownership model, including:

- leadership is critical regardless of the ownership model, particularly when it comes to innovation and transformation;
- bureaucracy needs to be minimized;
- it is difficult for any utility to balance competing for community goals (e.g., low rates, 100% clean energy); and
- there is an inherent conflict of interest with vertically integrated utilities as they will always favor their own generation above others' generation.

5.1.1.2 **Waialua**

The workshop was held at the Waialua High and Intermediate School in Waialua. There were 6 participants.

5.1.1.2.1 Priorities for Stakeholders

Stakeholders raised a range of priorities during the discussion. They included interest in diversifying energy generation sources, adding more renewables, building in system redundancies, and using new technologies (e.g. smart grid – real-time monitoring and pricing) for building resiliency and to reduce the cost of electricity. Stakeholders were also interested in improved customer service and reducing bureaucracy. Many also expressed an interest in more consumer choice and competitive generation choices.

There was also interest in more opportunities to generate revenue streams for customers, more planning for recovery after disasters, and more consumer education from the utility on renewable energy and reducing one's carbon footprint.

The stakeholders highlighted the following areas where HECO performs well:

- Provides reliable electricity (arose many times)
- Good maintenance, service, and response time
- Provides good jobs
- Good payments for households with PV
- Working towards a Renewable Portfolio Standard
- Use of technology (e.g., outage map)

5.1.1.2.2 IOU

Stakeholders felt that this model offers stable leadership, reliable and consistent service, and benefits from a history of service and knowledge of communities. They also raised that it offered less competition for independent power producers.

5.1.1.2.3 Muni

There was a consensus in the group that this model would be too political and raise equity/justice concern for rural areas whose priorities may be underrepresented.

5.1.1.2.4 Co-op

Stakeholders saw the benefits of this model being that the consumer-owner is the decision-maker and viewed the direct access that consumers have to the utility as a benefit. However, they raised the concern that without robust participation, a small group could gain control of the co-op. The sentiment seemed to be shared that a co-op could work on other islands, such as the Big Island, but was not the right fit for Oahu given the urban-rural differences and the large population size.

5.1.1.2.5 Wires-Only

The stakeholder group had a strong interest in a wires-only model. There seemed to be a consensus that this would be a better model for Oahu than a muni or co-op, and that it offered more competition in the generation field than a vertically integrated IOU, which would help Hawaii meet its clean energy goals. Stakeholders felt that competitive generation could also lower costs for consumers.

5.1.1.2.6 Other

Stakeholders shared that more examples of ownership models from other jurisdictions would be helpful – both successful and unsuccessful. Concern was also raised about poor utility service for Kalaeloa, which is on a navy grid system that needs upgrades. The potential for undersea cables connected the island was also discussed, as well as grid modernization to help lower costs via new technologies. Finally, the B-corp model was also raised during the discussion, and all the stakeholders expressed interest in more study and information on this model, especially based

on aligning incentives more closely with community needs and away from prioritizing only shareholder profit for the IOU.

5.1.2 Hawaii County

Two meetings were held in Hawaii County, one in Kona and one in Hilo.

5.1.2.1 Hilo

The workshop was held at the Waiakea High School in Hilo. There were 14 participants.

5.1.2.1.1 Priorities for Stakeholders

Stakeholders raised many priorities for their utility during the large group discussion. One strong theme was around affordability and equity, with stakeholders raising concern about the affordability of electricity, and the affordability of onsite renewable energy (e.g., rooftop solar). Stakeholders felt there should be more equitable ways to add renewable energy to the grid, such as incentive programs for lower-income households/residents for their bills or for participation in renewable energy generation.

Another theme was around innovation with stakeholders wanting to see a more intelligent grid and more distributed storage technology, as well as better integration of new grid technologies and more holistic thinking about interconnected systems (e.g., the connection between transportation systems electrification and the grid).

Some stakeholders also mentioned wanting to see more utility-scale solar, less reliance on existing geothermal, opportunities for local island ownership, and more underground power lines for resilience and aesthetics.

The stakeholders highlighted the following areas where HELCO performs well:

- Provides reliable electricity
- Responsive to emergencies
- Adding more renewable energy to the grid
- Positive community presence
- Provides good jobs for the community
- Collaborative partners

5.1.2.1.2 IOU

Stakeholders expressed that IOUs have a lot of resources. However, they felt that the investor-driven incentive meant less investment in renewable energy and that the profits would go off-island. Several stakeholders highlighted that IOUs could have strong leadership. Some shared the impression that IOUs have more power with the PUC on utility dockets than other parties. Several stakeholders also raised that IOU management seems overly paid and that rates were too high with this model. However, stakeholders shared that the IOU model does offer stability.

5.1.2.1.3 Muni

Stakeholders were concerned that a muni would require very engaged citizens, but ultimately this model would be subject to the "whims" of politicians. There was not much interest expressed in this model by participants for the Big Island.

5.1.2.1.4 Co-op

Many stakeholders were supportive of the co-op model. They felt it can give people more voice and decision-making power than other models. However, they also noted that to work well, a co-op needs engaged and active members, which requires a strong education effort. Stakeholders also highlighted the need for a co-op to have strong leadership and to invest in the future via R&D. For a transition to this model to work, the Big Island would need a trained workforce to draw from, as well as access to lower-cost financing.

5.1.2.1.5 Wires-Only

The stakeholders did not discuss wires-only utilities in detail.

5.1.2.1.6 Other

Stakeholders were most interested in a model that would give them the most voice and power with their utility. They also shared the need for strong leaders running utilities. They expressed some concern at transition costs between different models. One stakeholder also raised the need to plan for people who are going off grid in rural areas.

5.1.2.2 **Kona**

The workshop was held at the Natural Energy Laboratory of Hawaii Authority in Kona. There were 20 participants.

5.1.2.2.1 Priorities for Stakeholders

Stakeholders in Kona discussed a number of priorities for their utility, with reliable service and a large amount and diversity of renewable energy sources on the grid arising most often in discussion about what stakeholders value about their utility.

In discussing what stakeholders see as additional priorities for their utility, they emphasized strongly lower cost electricity and expressed concern that rates were too high currently, especially for lower-income households. The discussion also raised the priority of a more agile, faster utility, especially in terms of innovation and renewable energy. Innovation ideas raised as examples included smart grid technologies and buffer systems. Many stakeholders would like to see more renewable energy at the customer and grid-scale level and wanted customers owning distributed generation as "part of the solution, rather than something that has to be accommodated."

Additional themes that arose included a desire to buy power directly from power producers, for more safety measures on the grid to prevent accidents, and for more geothermal energy investments and projects. In the small groups, stakeholders also shared a desire to see more gasification of solid waste, island specific solutions, and a diversity of renewable energy to ensure resiliency.

The stakeholders highlighted the following areas where HELCO performs well:

- Provides reliable service (arose many times)
- Has high penetration and diversity of renewables on the grid
- Accessible online portal and online service options
- Locally based company
- Makes timely repairs

5.1.2.2.2 IOU

Some stakeholders expressed concern that there was a misalignment between IOU priorities and community desires since an IOU is driven by investor priorities and the need to make shareholder profit. A reoccurring theme raised about the current IOU model is that it is not seen to be responsive to consumer needs and does not lead to innovation, both in terms of long-term thinking and adoption of new technologies. Some stakeholders also expressed that an IOU is not local enough, in that employees are local, but they aren't empowered as decision-makers. Stakeholders raised that an IOU can have more stable leadership and provide more reliable service, but that they are inherently conservative in their actions.

5.1.2.2.3 Muni

Stakeholders expressed caution at the idea of county leaders overseeing a municipal utility, raising politics as a concern. They also expressed concern that the geography of the island would make a muni model challenging. In terms of advantages, stakeholders raised that a muni would be more responsive to consumer priorities. However, there seemed to be consensus among the stakeholders that a municipal model was not the right fit for the Big Island.

5.1.2.2.4 Co-op

Stakeholders felt that a co-op model would provide better alignment between utility incentives and community interests than the current IOU model, and would be more responsive and trusted by consumers. Some stakeholders felt that a co-op could also lead to lower energy prices. However, some stakeholders saw risks in the co-op model, mainly in the community being responsible for the grid, especially after a hurricane. It was also noted that Kauai, which has a co-op, is a smaller island, and that the model might not work as well given Big Island's larger size geographically and in terms of population. Stakeholders familiar with Kauai's co-ops also shared that effective leadership was key and that a co-op model means that a community's collective desires can be reflected in the utility's actions. Participants saw a primary barrier to the co-op model being that the transition requires a willing IOU seller, which, because HELCO does not appear to be a willing seller, could lead to expensive financing and debt. Other stakeholders noted that the Big Island would qualify for USDA Rural Utility Service low-cost financing.

5.1.2.2.5 Wires-Only

Stakeholders expressed interest in the IDER model that would bring more distributed energy resources to the grid. Many also expressed interest in a separation between generation and transmission ownership if it would allow them to buy power directly from the producer and/or support more distributed energy resources and microgrids. If the Big Island moved to this model, stakeholders raised the concern of stranded assets for the IOU.

5.1.2.2.6 Other

Stakeholders emphasized that whichever model would lead to lower electricity prices would be most desirable, as would a model that best aligns utility incentives with community interests and policy priorities. Additionally, they pointed out that a utility's ownership model was dependent on the leadership that the utility had, and that any model could be better or worse depending on the leadership. Based on this, the stakeholder group seemed interested in the future discussion of regulatory solutions to better align utility incentives. Ideas raised included revisiting the rate-base model and de-emphasizing over-investment in generation and other assets, and ways to support and empower local leaders.

5.1.3 Kauai County

The workshop was held at the Chiefess Kamakahelei Middle School in Lihue. There were 27 participants, a large majority of which shared that they were currently or historically associated in a formal manner with KIUC.

5.1.3.1 Priorities for the Stakeholders

The stakeholders placed a high value on local control of utility decisions and opportunities for customers to be engaged in the process. Additionally, the stakeholders prioritized the efficient use of resources, ensuring utility leadership reflects the diversity of the island and providing energy education to both the utility staff and customer-members.

The stakeholders discussed in detail what KIUC is doing well, including:

- investing in and expanding renewable energy generation, including exceeding state objectives;
- responding to repair and maintenance needs;
- being open to innovative opportunities;
- providing reliable service and a track record of functioning well;
- positive rate trends relative to other utilities; and
- providing local control through a democratic process, including member input on the strategic plan and public meetings held monthly.

5.1.3.2 IOU

In general, stakeholders expressed no distinct benefits to the IOU model. The perceived drawbacks included the lack of local control in the decision-making process, the board not being accountable to the consumers directly, and that decisions are based primarily on profit motivation

and ensuring that the returns are maximized for shareholders. The stakeholders felt that there is no incentive for IOUs to reduce expenses because expenses (e.g., fuel costs) are passed through directly to the ratepayers. Instead, they highlighted that the incentive is to increase capital investments because revenue is generated based on capital investments. Additionally, many stakeholders discussed that it is very difficult for the PUC to regulate an IOU to do what is in the community's interest.

The key challenge to changing to the IOU model was identified as convincing people that the change would be beneficial.

5.1.3.3 Muni

The municipal model was not considered a viable option by stakeholders due to concern over political influence and inefficient use of resources if the utility were managed and operated by the local government. However, it was noted that one benefit of this model is that it has a structural set up with which the community is already familiar (e.g., county/city government) and that citizens have a direct influence on decision making when they can elect the board.

Stakeholders discussed that while municipal utilities can work in large urban areas, the model would not be a good fit for Kauai with its disparate population centers and many rural areas. There was concern that munis can face difficulties in management due to political demands and utility management potentially conflicting. For example, elected board members may be more focused on simply keeping rates low to ensure reelection instead of increasing rates to make necessary investments in infrastructure. There was also concern that political influence may result in the redirection of any utility revenues to other, non-utility projects, hindering the utility's ability to operate efficiently. Some stakeholders felt that if the utility's finances could be kept completely separate from the local government's finances misappropriation of funds could be prevented. However, it was also noted that this could make it more difficult for a utility to access financing available to municipal governments.

There was a theoretical discussion about whether a public utilities district would be a good option for other counties in the state (not for Kauai). While no conclusions were drawn, some stakeholders thought that this might be a potential option for the City of Honolulu, though not for the entire City and County of Honolulu.

5.1.3.4 Co-op

Most of the discussion focused on the co-op model and, specifically, KIUC. Stakeholders explained that the co-op model works well for Kauai because it is a democratically controlled organization, allows for public input, and encourages efficient use of resources. The perception was that co-ops are motivated to drive down rates more than other ownership models because they are incentivized naturally to spend less money and to protect consumers. One stakeholder further explained that co-ops want to keep members connected to the grid and view "grid defection" as their competition. Similarly, in this model, the stakeholder saw a mutual interest between the utility and the member to ensure the utility operates efficiently. KIUC was seen to be able to set goals above and beyond the state's goals in order to meet the community's priorities.

Stakeholder saw some unique benefits to the co-op model including that operating as a nonprofit provides benefits that other ownership models do not, co-ops have access to many resources through co-op networks, including healthcare and IT systems, and co-ops have access to FEMA support following natural disasters. Stakeholders explained that KIUC has access to low-cost financing and is less dependent on debt than typical IOUs. Unlike other models, stakeholders discussed that the PUC could not regulate a utility to align their operations with consumer benefits as well as the co-op model inherently delivers.

One of the challenges to the current co-op model that was highlighted is that KIUC is governed by 3 entities, namely the (i) lender, (ii) PUC, and (iii) Board, with varying expectations and requirements. Stakeholders viewed the regulation by the PUC as hindering KIUC's operations because it can take too long to get approval for projects and programs. Stakeholders recognized that it could be difficult to retain or attract qualified staff because the compensation packages do not compete with IOUs' packages. Though membership involvement was identified as a primary benefit of this model, it was acknowledged that it works best when members are knowledgeable about utility operations and the electricity sector otherwise it can be difficult to get necessary projects or programs passed. Some stakeholders mentioned that a potential problem with the model is that board members can be hesitant to approve controversial projects or programs for fear of being voted out.

There were some critiques of the current model that were raised by stakeholders, including that the utility could do more to reduce rates for customers and increase transparency in their decision-making process. One stakeholder expressed concern about closed session board meetings and the transparency of the decision-making process. Another stakeholder highlighted that KIUC could take better advantage of its unique situation as a test-bed for cutting-edge technology as well as improve the incorporation of data (e.g., energy efficiency and revenue data) to inform decisions.

Stakeholder discussed that KIUC's transition from an IOU was not easy but that they had access to resources (e.g., training, education, and visiting experts) from the national cooperative system that helped immensely. After the transition, it was challenging to manage expectations, as members wanted to see immediate results while change in operations and management took time due to the utility's previous operations and investments in infrastructure and programs. There was recognition that Kauai had a unique opportunity to transition to a co-op in that the incumbent utility, Citizens' Communications Kauai Electric, was for sale, and they had the community support to create a co-op. During the transition, investing in education within and outside of the organization was seen to be integral to the successful transition.

If other counties decide to transition to a co-op, the stakeholders expected that KIUC would provide technical support to ease the transition. Additionally, they discussed the potential for KIUC and other Hawaii co-ops to share resources to benefit from economies of scale (e.g., HR department, software, physical resources). The stakeholders theorized that a co-op could work in Hawaii County, Maui County, and outside of Honolulu on Oahu, but that it may not work for the City of Honolulu. While Kauai qualifies for USDA grants that benefit KIUC, stakeholders were uncertain if other counties would also qualify and how this could impact the benefits of a co-op model.

5.1.3.5 Wires-Only

The stakeholders did not discuss wires-only utilities in detail.

5.1.3.6 Other

Regardless of ownership model, the stakeholders noted there are uncontrollable outside forces (e.g., price of oil) that impact a utility's operations and costs, and therefore the rates. The stakeholders expressed the benefits of lower rates, including the ability to attract more businesses and drive economic development.

In relation to KIUC, there was much discussion about the need to reduce what stakeholders viewed as unnecessary regulation by the PUC since the utility is a co-op. Some regulation was viewed as hindering KIUC's ability to implement activities that meet customers' demands and align with the strategic plan.

5.1.4 Maui County

The Project Team held three meetings in Maui County, one on Maui, Molokai, and Lanai. The summaries below are separated by meeting.

5.1.4.1 Lanai

The workshop was held at the Lanai Community Center in Lanai City. There were 18 participants.

5.1.4.1.1 Priorities for the Stakeholders

The stakeholders stated that their primary priority is for the utility to provide reliable, affordable electricity. The stakeholders valued utility investments in necessary infrastructure and maintenance to ensure reliable electricity now and in the future.

The opportunity for community input in the decision-making process was identified as highly important, and some stakeholders expressed interest in local ownership of the utility, though they saw difficulties in the community operating a utility. Similarly, stakeholders valued utility responsiveness to community needs, including improving planning for disaster recovery and communication to the community regarding the status of infrastructure damage and repairs.

Planning for the 100% renewable energy future was identified as an important role for the utility and an effort that would require innovation. The stakeholders valued utility incentives for the uptake of energy efficiency and renewable energy technologies, and the general increase of renewable energy on the grid.

The stakeholders highlighted the following as areas where MECO performs well:

- provides generally reliable electricity
- addressed the damage quickly after the last storm and restored service

5.1.4.1.2 IOU

The stakeholders identified two main benefits to the IOU model: economies of scale and some investment risk falling on shareholders. The current model, with MECO a part of the HECO Companies, allows MECO to rely on and share resources with the other HECO Companies, reducing costs and increasing efficiencies. There was a discussion that if the utility fails, the shareholders risk losing their money instead of the community.

The primary disadvantage to the IOU model was viewed to be the lack of control and input the community has on the utility decision making process. There is concern that an IOU does not consider what is best for the community since it is primarily driven to increase profits.

5.1.4.1.3 Muni

There was strong opposition by participants to considering a municipal utility model for Lanai due to concern over the influence of politics on utility management, a general distrust of government officials to operate it efficiently, and worry that corruption could be rampant. Multiple stakeholders pointed to the rail development in Honolulu as an example of mismanagement of public funds. It was discussed that a disadvantage of this model is that the county would have to take on debt to change to this model.

Nevertheless, the stakeholders noted that municipal utility leadership is directly accountable to the community and a part of the community and therefore incentivized to incorporate the community's best interests into decisions. There is potential for this model to result in lower rates because it is not primarily profit-driven. One stakeholder disagreed with the group and pointed to successful municipal utilities as examples for why the option should be considered for Lanai.

5.1.4.1.4 Co-op

The stakeholders discussed that the co-op model is unique in its ability to incorporate member input in the decision-making process and identified this as a potential way to ensure that decisions were made with the specific needs of Lanai in mind. There was the perception that the co-op model is the nimblest, allowing a utility to adapt operations and investments more quickly based on community need.

There were concerns about whether Lanai had the staff resources on the island with sufficient technical ability to manage the grid and utility operations since some of these operations for MECO are managed by MECO staff based in Maui. The stakeholders raised the point that it would be difficult to raise capital to purchase MECO's Lanai assets, and that the costs to maintain the grid may be too high. There was a lot of discussion about the unique challenges that exist on Lanai and how it may be difficult for a co-op to function well with a very small population and a single landowner that owns approximately 95% of the island.

5.1.4.1.5 Wires-Only

The stakeholders did not discuss wires-only utilities in detail.

5.1.4.1.6 Other

Regardless of ownership structure, the stakeholders discussed that it is unlikely for the community to raise enough capital to purchase the utility and there may not be enough technical staff on Lanai to effectively manage and operate a utility.

The stakeholders recognized that Lanai is a small island with a small population and, because it is not self-sustaining, it must rely on imports. However, there was strong support for this study to assess the options for Lanai individually rather than including it in the analysis for Maui County as a whole because of the different goals, needs, and contexts of each island in the county.

Additional comments included:

- The current grid will need to be upgraded to achieve the 100% clean energy goal. It's difficult to envision what 100% clean energy looks like for Lanai.
- The Jones Act results in substantially increased costs for everything on Lanai (and in Hawaii broadly) and should be repealed.
- NextEra may have been a lost opportunity for improvements to the infrastructure.
- There are too many studies. It's important to move to implementation.

5.1.4.2 **Maui**

The workshop was held at the Wailuku Community Center in Wailuku. There were 19 participants.

5.1.4.2.1 Priorities for the Stakeholders

Stakeholders highlighted a number of areas that they consider to be priorities for their utility. Many stakeholders expressed the desire for the community to have more involvement in the utility's decision-making process, for there to be a formal process through which to participate, and for the utility to focus on the customers' needs. In addition to providing reliable electricity, the stakeholders value increasing the diversity of fuel mix with a particular focus on renewable energy [including solar, wind, ocean thermal energy conversion ("OTEC"), hydrogen, and geothermal] as well as increasing the opportunity for customers to interconnect distributed renewable energy resources. Recognizing that renewable generation on Maui is high, the stakeholders would like to see improved management of those sources to minimize curtailment. Stakeholders also expressed the importance of innovation, infrastructure resiliency, and improved service to less populated areas.

The stakeholders discussed what MECO is doing well, including:

- providing reliable electricity, particularly in populated areas;
- managing fossil fuels; and
- providing an opportunity for customers to engage in discussions with the utility.

5.1.4.2.2 IOU

The discussion of IOUs focused on both the incumbent utility, MECO, as well as a theoretical case where a new owner purchased the utility but continued to operate as an IOU. In general, the stakeholders decided that IOUs can attract and retain a talented workforce, that their access to private capital is beneficial, and that their profit motive can drive efficient investments. The group felt that there are benefits to MECO being a part of the HECO Companies, including resource sharing between the companies and cost savings from economies of scale.

When discussing the potential for a new parent company, there was concern that a parent company located in another jurisdiction may have to comply with different rules, making it more challenging for the PUC to regulate. One stakeholder stated that if the parent company was based in Delaware, the board would be restricted to solely valuing profits in their decisions while Hawaii has passed laws that allow for boards to incorporate other factors (e.g., sustainability goals).[10] This difference allows the PUC greater flexibility in regulating the utilities and ensuring state goals are considered in utility operations and planning. Additionally, stakeholders were worried that there would be less local influence if a parent company from out of state ran the company and their responsibility would continue to be to shareholders instead of the community.

There was particular interest in understanding more about how the B-corp model could bridge the IOU model and co-op model to better incorporate community and sustainability goals into the utility's decision-making process. They did recognize that costs may be higher with a B-corp than a traditional IOU.

5.1.4.2.3 Muni

While the group did not focus much on discussing this model, there was a general concern about the potential for politics to influence utility management under a municipal model. There was concern that the county would not have the financial, expertise, nor sufficient staff to effectively manage a utility. One stakeholder explained that in his experience with Independent Power Producers, they see more risk in working with munis or co-ops than with IOUs. It was noted that a benefit of municipal utilities is that they are protected from going bankrupt. The group also questioned whether the county had the financial resources to purchase the utility.

5.1.4.2.4 Co-op

There was agreement among the stakeholders that a primary benefit of co-ops is the customer engagement in decision making that the model allows and the incentives to minimize costs to ratepayers. The group noted that it would probably work best in an engaged and informed community and were concerned that member participation in voting may be low, citing KIUC's recent board elections. Additionally, it was mentioned that it could be difficult to educate the

[10] The participant mentioned two state laws: one that allows boards to incorporate other factors than solely profits and the B-corporation law.

entire membership on utility operations and that this could result in members making decisions for the utility that may not be well informed.

Co-ops were considered to be incentivized to incorporate customer impact into budget decisions and that, unlike IOUs, did not have an incentive to invest in unnecessary capital improvements.

The group mentioned that co-ops might run the risk of poor medium- and long-term planning due to budget constraints, board members being concerned about reelection, and members being most concerned about keeping short-term rates as low as possible. Similar to the discussion for munis, the group mentioned that IPPs consider it riskier to work with co-ops and it is beneficial that co-ops are protected from bankruptcy. However, one member countered that the power purchase agreement process has typically been smoother with KIUC than with the HECO companies.

It was pointed out that KIUC has a very low cost of capital. However there was concern that it could be more difficult to raise capital in the event of an emergency. The group questioned, however, whether Maui would be able to access capital at a similar cost as it may not be eligible to access federal financing programs targeting rural communities due to the populations of more urban areas (e.g., Wailuku/Kahului).

5.1.4.2.5 Wires-Only

Some stakeholders concluded that separating the ownership and operation of the transmission and distribution from the generation would be the best path to creating a competitive market for generation, forcing the utility to become more flexible and competitive, resulting in the best rates possible for ratepayers. They expressed a desire to learn more about an Independent System Operator ("ISO") and other similar models, with a recommendation to review the Midwest ISO and others.

In addition, it was mentioned that MECO, or the HECO Companies more broadly, may be interested in changing their business model simply to be more competitive and responsive to customers, particularly by moving to owning and operating only transmission and distribution and divesting in its generation assets.

5.1.4.2.6 Other

Many stakeholders agreed that a change in ownership model might not address the community's priorities. The stakeholders suggest that focusing on regulatory changes to incentivize MECO to better align its actions with community goals may be more effective. Regardless of ownership model, strong leadership within any utility was identified as necessary to drive transformation and innovation. It was discussed that leadership would be wise to consider how utility investment today can lock-in the utility to a certain technology which may be obsolete in the near future. While it is impossible to know how technology would change, stakeholders expressed that it would be useful to ensure this is at least considered by utility leadership.

When discussing a theoretical transition to a new ownership model, the group identified some potential problems to consider:

- The incumbent utility is not for sale.
- How would the purchase of the incumbent utility be financed?
- Would there be any difficulties in retaining and/or finding staff?
- The risk of stranded assets could be costly.
- Would reliability and system upgrades be maintained during a transition?
- The transaction costs could be extremely high, which ratepayers would bear.

Additional comments included:

- One stakeholder suggested that it is necessary for there to be a robust interconnection between the islands to allow the utilities to be more flexible and bring down costs.
- There should be an independent organization that is responsible for ensuring reliability standards are met.
- There was concern that the utility will be unable to manage the electricity flow and infrastructure when the percentage of IPPs increases substantially which was considered to be inevitable if Maui is to meet the renewable energy goals.
- The private market, specifically individuals, have the cheapest cost of capital and should be considered in the analysis.
- Many seniors are unable to afford to install solar and also cannot afford to cover the costs to maintain the grid when other ratepayers go off-grid or install solar and no longer pay for their use of the grid.
- There was some interest in exploring geothermal options on Maui.

5.1.4.3 **Molokai**

The workshop was held at the Mitchell Pauole Community Center in Kaunakakai. There were 8 participants.

5.1.4.3.1 Priorities for the Stakeholders

After safe and reliable service, the primary priority identified by the stakeholders was for there to be ample opportunity for the community to engage in the utility's decision-making process. This could include some form of local ownership, the opportunity to buy-in, or substantially increased engagement with MECO (e.g. "early and often"). Additionally, the stakeholders valued transparency in the decision-making process.

The stakeholders highlighted the importance of equity in the electricity sector. For example, it was noted that community members that are not connected to the grid should have an affordable option to connect if they choose. The stakeholders noted the need for utility infrastructure to be improved in many areas. While many residents are unable to afford or cannot install solar on their roofs, the stakeholders would like to ensure that all community members could access the benefits of solar. Additionally, some stakeholders want those who choose to go off-grid to be provided the ability and support to do so.

In relation to renewable energy, the stakeholders explained that it is the community's kuleana to care for natural resources, including the sun, wind, and ocean. As such, the community considers

it integral for the community members to be consulted when the utility or developers are considering using those resources to generate power. The stakeholders highlighted the importance of a diverse energy mix, particularly distributed solar. There was also some interest in considering salt water air conditioning for populated areas and opportunities to increase the capacity for electric vehicles. In addition to diverse resources, the stakeholders would like to see the utility value flexibility in grid management (including batteries to increase flexibility and to separate generation across the five circuits).

The stakeholders also highlighted the following priorities:

- It is imperative that lifecycle impacts of investments are considered. For example, how will infrastructure be decommissioned when it is no longer used? How will solar panels be disposed? How will any contaminated sites be cleaned up?
- Interconnection via undersea cable to Oahu and development of large wind projects is not welcome. Resources on Molokai should be used only to provide for Molokai.
- It is important to consider what is technically and financially feasible for Molokai.

The stakeholders highlighted that MECO generally provides reliable service to those connected to the grid.

5.1.4.3.2 IOU

In general, the stakeholders expressed distrust of the HECO companies' leadership and concerns that the decisions being made do not reflect nor take into account the community's values. Though this was expected to be inherent in all IOUs, the stakeholders were concerned that it would only be enhanced if the IOU leadership does not live in the community. The lack of a process for community engagement in IOU decision making was considered to be a detriment to this model though there was some discussion about the beneficial impact of MECO's recent efforts in community engagement. The increased access to private capital accessible to IOUs was considered to be a potential benefit, particularly for financing large-scale projects.

There was interest around a B-corp as a potential option for ensuring that an IOU better incorporates the community's needs into the decision-making process. The community would like to learn more about B-corps. There was a concern, though, that the community's needs would still not accurately be incorporated into the process if the B-corp leadership was not from the community.

5.1.4.3.3 Muni

There was agreement from the stakeholders present that the municipal model is not a good option due to distrust of political officials and concern with the government's ability to efficiently and reliably manage an electric utility.

5.1.4.3.4 Co-op

The direct impact that the members have in the decision-making process was seen to be very beneficial. Under this model, the stakeholders felt that the community can trust that the utility is making decisions with the needs of the community in mind because the utility leadership lives within the community and knows the members. There was a discussion that this model could result in a more efficient use of local resources than others. There was interest in how access to federal financing under this model could be a lower cost option for financing investments in infrastructure.

There was recognition that the process of starting a co-op from scratch would be extremely difficult and, perhaps, infeasible for Molokai. Additionally, some stakeholders brought up that the community may not be able to raise the necessary capital to finance the purchase of MECO.

There was some interest in exploring a hybrid co-op/IOU model that would result in more community input in the utility's decision-making process but allow the utility to primarily function as an IOU.

5.1.4.3.5 Wires-Only

The stakeholders did not discuss wires-only utilities in detail.

5.1.4.3.6 Other Discussions

Regarding all models, the stakeholders highlighted that it could be extremely difficult and costly for any entity to purchase MECO since it is not for sale and that the high costs could make any transition unreasonable at this time. Additionally, regardless of ownership model, some stakeholders felt that there needs to be a neutral party that ensures that the utility is meeting safety, reliability, and other standards.

Throughout the workshop, the stakeholders discussed other areas of concern, including:

- that the 100% renewable energy goal was made without consulting the community on Molokai and is not what is best for Molokai;
- the Half Moon deal with MECO was discussed many times, and there are mixed feelings about the deal and its benefits to the community; and
- there was frustration that the PUC does not respond to questions from the community.

5.2 Bilateral Discussions

The teams conducted multiple bilateral meetings during the week, as listed in Table 3, meeting with 20 different organizations or individuals representing counties, utilities, non-profits, state and local elected officials, and the private sector. The comments are compiled by themes in the list below. They are not attributed to a specific individual or organization.

Figure 14. Bilateral Meetings

Team 1	
Island	**Organization/Individual**
9-Oct Hawaii	Hawaii Island Economic Development Board
	Paniolo Power
10-Oct Hawaii	Hawaii County
	Hawaii Island Energy Cooperative
	HELCO leadership
11-Oct Oahu	PACOM
12-Oct Oahu	City and County of Honolulu
	Oahu Economic Development Board
	Ulupono Initiative
	Rep. Chris Lee, Hawaii Legislature
	Independent Power Producer
	HECO Leadership
13-Oct Oahu	Core Group Call

Team 2	
Island	**Organization/Individual**
9-Oct Maui	Mayor Arakawa, Maui County
	Maui County
	MECO Leadership
10-Oct Molokai	MECO Management for Molokai
11-Oct Lanai	MECO Management for Lanai
12-Oct Kauai	Kauai County
	Former PUC Commissioner
	KIUC
13-Oct Oahu	Core Group Call

The comments from the bilateral meetings are summarized and combined by topics below.

5.2.1 Priorities

In addition to cost, priorities for customers include resiliency, reliability, and accessibility. For many, cost is the primary driver, but some place a higher value on the latter three. People want a more innovative utility and want to see more renewables brought on the grid.

Any utility needs to have insightful leadership, nimble and flexible strategic planning, and strong analytical capacity to be successful as the electricity sector transforms. The utility model is evolving and requires a change in the business model to be successful. To adapt, leadership must rely on data analysis to inform strategic development while also being forward thinking to identify potential opportunities.

There were many stakeholders who commented on the desire for local influence in the utility decision-making process. Utilities need to better engage customers, have discussions that are more accessible to the public, and be responsive to their needs. Otherwise, customers may choose to defect from the grid, which would compromise grid integrity. It was noted that while democratizing ownership of shared resources is valuable, technical expertise, management, and skills cannot be discounted.

Additional stakeholder comments include:

- There is a need for a better zone of risk-taking and collaboration.
- Each island should be considered separately (not just each county) because the needs and context are unique. A different model may work best on each island.
- This study seems like a waste of taxpayer dollars and is too little, too late now that the NextEra pressure is gone. But a merger could always come up again.
- The PUC needs the resources, capacity, competence, and independence to incentivize change.
- The acquisition costs of a transition in ownership would be extremely high and difficult for ratepayers or taxpayers to bear.
- Maui County is exploring options for using land that cannot be used for other productive purposes for community solar to benefit the low- and moderate-income community.
- OTEC will be a game-changer if it reaches commercialization.
- There is an important disaster management and safety perspective to consider and, therefore, a desire for island-able microgrids and resilience hubs.
- There is a need to focus on getting people to pay for renewable energy because of their values: the heritage of Hawaii's natural resources and ethic of thinking several generations into the future.
- There is a need to identify a no-regrets path to modernize the grid effectively and meet the state goals.

5.2.2 Affordability

Some stakeholders highlighted that the primary public interest is in not paying "$0.48/kWh." While ratepayers do not want to sacrifice reliability, resilience, and renewable energy, they need more affordable electricity for households and businesses. As electricity rates continue to increase, ratepayers become more interested in discussing alternative models. Anything that improves the ratepayers' sense of ownership and control of power would be welcome, as ratepayers want a voice in the decisions that result in the rates they are paying, even if the rates are high. There is a view that wealthier people exiting the grid have a negative financial impact on low-income ratepayers.

5.2.3 IOU

Some stakeholders felt that there is currently no alignment of incentives and a misalignment of interests between community interests and IOU operations. They see the utility getting paid for building assets while the ratepayers want reduced costs and more renewable energy. Ratepayers are then paying for investments in assets they do not want. The existing rate recovery model is a

problem and creates these incentives for the utility that do not align with customer priorities. Additionally, the IOU answers to shareholders, 70% of whom are not in Hawaii, and many of whom are large institutions. Removing the need for profit would be better. There is also little incentive currently for the utility to manage its rates.

Some stakeholders believe that the IOU wants control of supply and to be the seller, rather than accepting decentralized generation. HECO keeps investing in new generation when it would be a better role for independent power producers.

One stakeholder considered IOUs to typically be slow to innovate and generally not responsive to public input. In the current model, the competitive bidding framework is dysfunctional, and it takes years to receive interconnection decisions. Additionally, the utility ignores process, even when the PUC turns them down, so there is concern about what would happen if there is a transition to a less-regulated model. It is difficult to see how the current IOU model will work in the long-term in Hawaii.

Some stakeholders explained that a primary benefit of the current model is that the HECO companies (and customers) benefit from economies of scale and sharing of resources across the companies (e.g., human resources, legal, and regulatory staff; physical resources; etc.).

5.2.4 Muni

A transition to the municipal model was generally seen to be untenable by participants, as politicians would not have the will to follow through with condemnation of HECO assets, nor make any necessary constitutional or regulatory changes. Additionally, there was concern that government is too inefficient and political to run a utility well.

5.2.5 Co-ops

A co-op was attractive to many stakeholders, but it was recognized that it could be difficult to implement well in a geographically large and urban setting. However, it may make more sense for smaller islands with smaller systems. Stakeholders considered benefits of this model to include that it is quicker at bringing cost-efficient renewables online, nimble, proactive, and offers alignment between customer interests and utility action. The cost of capital for co-ops may be more economical and they are driven to keep rates low for members. Co-ops are also subject to less regulation, which can result in lower rates.

Stakeholders commented that the process of forming a cooperative utility is very difficult in the current market, as providing Hawaiian Electric Industries ("HEI"), the parent company to the HECO Companies, with a high enough offer to be acceptable would likely both 1) fail regulatory scrutiny and 2) result in a large amount of debt to be paid off through utility rates. KIUC is a unique utility which arose out of a unique situation. It was successful in transitioning to a co-op model because the incumbent utility was for sale, there was strong community leadership and support, and they had access to attractive financing options. It cannot be expected that this model would work in other counties simply because it has worked well for Kauai.

KIUC does provide a comparative example. Stakeholders expressed that HECO's perceived resistance to renewable energy is difficult to understand when KIUC has achieved 50% renewable energy with relatively stable rates. A stakeholder also felt there is a lack of understanding of the co-op model and that the co-op also owns the liabilities. The stakeholder believes that in Kauai, they had no choice but to become a co-op.

There was particular interest in the co-op model by stakeholders on the Big Island because of the island's rural nature and because of the existence of a legal cooperative entity.

5.2.6 Wires-only

Stakeholders discussed that if there is a wires-only model, there would need to be a completely independent body to select the PPAs. Stakeholders viewed that it is very profitable for utilities to own generation; a wires-only model could reduce rates by increasing competition in generation. Though some stakeholders expressed interest in this model and separating generation from transmission and distribution, one mentioned that the utility should not pull out entirely from ownership of generation. One stakeholder suggested that HEI can make their revenues by becoming a "21st century knowledge-based utility."

6 Conclusion

While the discussions at each workshop were unique as stakeholders expressed their values, and identified advantages and disadvantages of each model to address each community's specific needs, there were some themes that came up throughout the process, including:

- reliable electricity is a priority, and any impact that a different model may have on this must be considered;
- keeping rates as low as possible now and in the future, is a priority.;
- stakeholders greatly value the ability to be engaged in and influence utility decisions to ensure they are aligned with community needs, whether this be through local ownership opportunities or formal processes for engagement;
- there is a need for grid improvements, not just to meet the 100% clean energy goals, but to ensure reliability and resiliency, especially in preparing for severe weather;
- there is demand for more renewable energy, from more diverse sources, and for more opportunity for customer-sited generation;
- innovation will be necessary for the utility to be successful, and strong leadership, regardless of ownership model, is integral in encouraging innovation;
- competition is viewed by many as the best option for driving efficiencies and keeping rates low; and
- many stakeholders are concerned that equity, in terms of the cost of electricity and access to the benefits of renewables, is not being considered sufficiently.

6.1 IOU

The primary concern with the IOU model expressed by stakeholders across all workshops is the lack of community influence in the decision-making process. Most stakeholders felt that the current model provides generally reliable service and benefits from economies of scale, as resources are shared among the HECO Companies. Stakeholders see this model as being less likely to invest in renewables, providing fewer opportunities for IPPs, and being less innovative than desired.

6.2 Muni

While stakeholders liked that this model allows for community members to have a more direct influence on utility decisions, most stakeholders were concerned about the potential for political influence to hinder utility operations. Additionally, many expressed their worry that the government would not operate the utility efficiently. With the exception of a few stakeholders, there was little interest in this model.

6.3 Co-op

Most stakeholders agreed that the primary benefit of this model is the ability that consumers have to directly impact utility decisions. Many pointed to KIUC as a successful example of the co-op model and, based on that example, the potential that this model has for providing lower rates. A number of stakeholders mentioned that this model works best with educated, engaged members,

and there are difficulties in achieving this. The interest in the co-op model varied by island, with more interest expressed on Kauai and the Big Island (particularly at the Hilo workshop). Some stakeholders at the workshops on Oahu (both Waialua and Honolulu) and Maui were not sure that this model would work on their respective islands due to population size, geographical diversity, and concerns about qualifying for rural financing programs.

6.4 Wires-only

This model was discussed in detail during the workshops in Honolulu, Kona, Maui, and Waialua. The stakeholders felt that a primary benefit of this model is its potential for encouraging competition in generation and that this could result in lower rates.

6.5 Other Interests and Concerns

Many stakeholders expressed a strong interest in better understanding the B-corp model, particularly during the workshops on Hawaii, Maui, and Molokai. The B-corp option was identified at multiple meetings as a potential option for incorporating community priorities into the decision-making process for an IOU utility. Concerns about equity, in terms of rates, access to electricity, and access to the benefits of renewables were raised at multiple workshops, particularly at Hilo, Honolulu, Molokai, and Waialua. Many stakeholders across the workshops acknowledged that the cost to purchase the incumbent utility would be extremely high and that this cost would be borne by ratepayers or taxpayers, potentially making any change in ownership model untenable at this time.

6.6 Future Stakeholder Engagement Opportunities

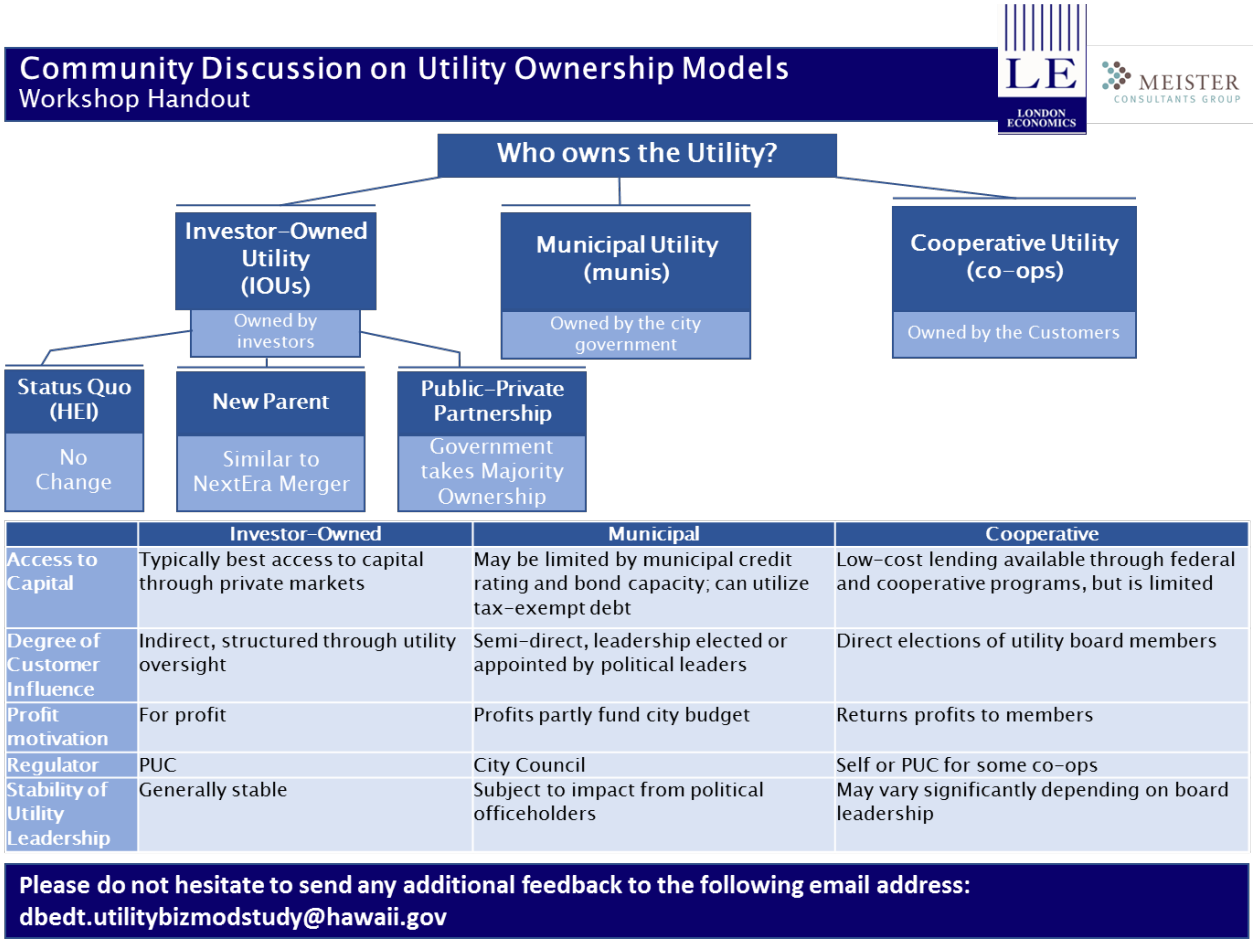
The results from these workshops and the other stakeholder engagement conducted throughout this project will be incorporated into the analyses and the final report, to be submitted to DBEDT in October 2018. Feedback will be collected over the course of the project. All feedback related to the ownership model analysis that is received by November 13th, 2017 will be summarized and added as an addendum to this report. All other feedback will be incorporated into future reports submitted under this project.

The Project Team will continue to engage with stakeholders to keep them apprised of the status of the project and to receive their input related to the project. The Project Team will be conducting stakeholder workshops on the regulatory model analysis in the spring of 2018 which will be open to the public. The feedback from those workshops will be incorporated into the regulatory analysis.

7 Appendix A: Utility Ownership Model Summary Handouts

The workshops participants were provided with a workshop providing a high-level overview of different ownership models. The worksheet is included in

Figure 15. Utility Ownership Model Summary Handout (page 1)



Community Discussion on Utility Ownership Models
Workshop Handout

LE LONDON ECONOMICS · MEISTER CONSULTANTS GROUP

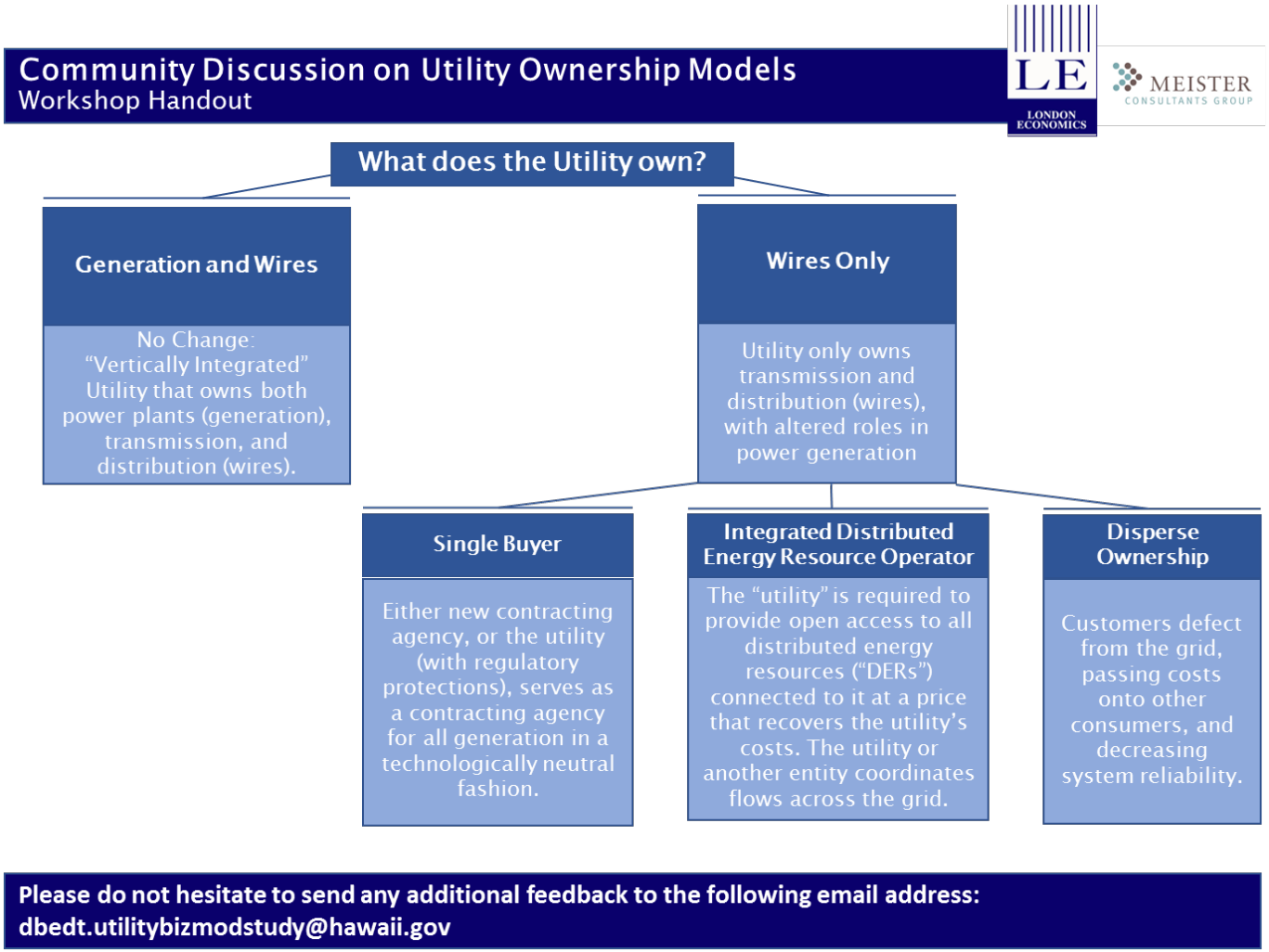
Who owns the Utility?

- **Investor–Owned Utility (IOUs)** — Owned by investors
  - **Status Quo (HEI)** — No Change
  - **New Parent** — Similar to NextEra Merger
  - **Public–Private Partnership** — Government takes Majority Ownership
- **Municipal Utility (munis)** — Owned by the city government
- **Cooperative Utility (co–ops)** — Owned by the Customers

	Investor–Owned	Municipal	Cooperative
Access to Capital	Typically best access to capital through private markets	May be limited by municipal credit rating and bond capacity; can utilize tax–exempt debt	Low–cost lending available through federal and cooperative programs, but is limited
Degree of Customer Influence	Indirect, structured through utility oversight	Semi–direct, leadership elected or appointed by political leaders	Direct elections of utility board members
Profit motivation	For profit	Profits partly fund city budget	Returns profits to members
Regulator	PUC	City Council	Self or PUC for some co–ops
Stability of Utility Leadership	Generally stable	Subject to impact from political officeholders	May vary significantly depending on board leadership

Please do not hesitate to send any additional feedback to the following email address:
dbedt.utilitybizmodstudy@hawaii.gov

Figure 16. Utility Ownership Model Summary Handout (page 2)



8 Appendix B: Discussion Matrix Worksheet

The worksheet below was distributed to workshop participants and used to guide the discussion in the second breakout.

Figure 17. Discussion Matrix Worksheet

Stakeholder Worksheet	**Investor-Owned Utility (Shareholders own the utility)**	**Municipal Utility (The city/town government owns the utility)**	**Cooperative Utility (Customers own the utility)**
What benefits do you see from this model?			
What drawbacks do you see from this model?			
What is accomplished by this model of utility ownership? **Does it address your priorities?**			
What are the key challenges to changing to this utility ownership model?			
Do you have any additional feedback, questions, or concerns?			

9 Appendix C: Presentation Slides

The presentation slides are available at https://energy.hawaii.gov/utility-model.

10 Appendix D: Outreach Flyers

All outreach flyers can be accessed at http://dbedt.hawaii.gov/blog/17-55/ or at the individual links below.

City and County of Honolulu

- Waialua https://dl.dropbox.com/s/13y4o5fwzilztkl/Flier_Waialua%20High_10-11-17.pdf?dl=0
- Honolulu https://dl.dropbox.com/s/n1spjuulbn31iai/Flier_Honolulu_10-13-17.pdf?dl=0

Hawaii County

- Hilo https://dl.dropbox.com/s/q8iqscar28cpauw/Flier_Waiakea%20High_10-10-17.pdf?dl=0
- Kona https://dl.dropbox.com/s/rhgk7dqd4xs4wlf/Flier_NELHA_10-9-17.pdf?dl=0

Kauai County

- Lihue https://dl.dropbox.com/s/8r0hniy9lfih6ai/Flier_Chiefess%20Khamakahelei_10-12-17.pdf?dl=0

Maui County

- Kaunakakai, Molokai https://dl.dropbox.com/s/ohaqsekmqfh3h38/Flier_Mitchell%20Pauole%20Main%20Hall_10-10-17.pdf?dl=0
- Lanai City, Lanai https://dl.dropbox.com/s/p1c1qy5orq3rkxa/Flier_Lanai%20Community%20Center_10-11-17.pdf?dl=0
- Wailuku, Maui https://dl.dropbox.com/s/xzt8yhj2paf6dhl/Flier_Wailuku%20Community%20Center_10-9-17.pdf?dl=0

11 Appendix E: Press Release

The Project Team sent the following press release to the media outlets identified in the report. Additionally, DBEDT sent out the media release available at http://dbedt.hawaii.gov/blog/17-55/.

Contact: Len Trinidad, Project Lead, London Economics International
Phone: (1) 617-9337229
Email: dbedt.utilitybizmodstudy@hawaii.gov

FOR IMMEDIATE RELEASE (OR RELEASE 1 WEEK PRIOR TO EVENT)

Community Discussion on Electric Utility Ownership Models to Achieve Hawaii's Goals (Week of October 9th)

The Hawaii legislature has directed the Department of Business, Economic Development & Tourism (DBEDT) to undertake a study on the future of utility ownership models on each island in Hawaii. As a part of this study, London Economics International and Meister Consultants Group will be holding a community meeting for residents to share their thoughts on the future of electric utility ownership and the role the utility plays in achieving community and state goals, including achieving 100% renewable energy and minimizing rate increases.

The meetings will be held on the following dates and locations:

Maui County:

- **Wailuku, October 9th, 5:30-7:00.** Wailuku Community Center, 395 Waena St. Event Flyer | RSVP Link
- **Kaunakakai, October 10th, 5:30-7:00.** Mitchell Pauole Center Main Hall, 90 Ainoa St. Event Flyer | RSVP Link
- **Lanai City, October 11th, 5:30-7:00.** Lanai Community Center, Eighth St. and Lanai Ave. Event Flyer | RSVP Link

Hawaii County:

- **Kailua-Kona, October 9th, 5:30-7:00.** NELHA Research Campus, Hale Iako Building, 73-870 Makako Bay Drive. Event Flyer | RSVP Link
- **Hilo, October 10th, 5:30-7:00.** Waiakea High School, 155 W Kawili St. Event Flyer | RSVP Link

Kauai County:

- **Lihue, October 12th, 5:30-7:00.** Chiefess Kamakahelei Middle School, 4431 Nuhou St. Event Flyer | RSVP Link

The City and County of Honolulu:

- **Waialua, October 11th, 5:30-7:00.** Waialua High & Intermediate School. Event Flyer | RSVP Link
- **Honolulu, October 13th, approx. 6:00 -7:30.** *Location still to be confirmed. Please RSVP for email updates.* Event Flyer | RSVP Link

We welcome everyone's participation and kindly request that you RSVP at the link above. Light refreshments will be served.

For those unable to participate in person, you may submit any feedback by emailing it at dbedt.utilitybizmodstudy@hawaii.gov. If you have questions about the meetings or project, please email them also at the same email address above.

12 Appendix F: Email Invitation Text

Stakeholders across the state that had been engaged with this project in the past, expressed interest in participating, or were identified through discussions with DBEDT and the Core Group were sent the following email invitation.

Dear Stakeholder:

As you may be aware, the Hawaii State Legislature has directed the Department of Business, Economic Development, and Tourism to review different utility ownership and regulatory models for each county. Our firm, London Economics International ("LEI"), together with Meister Consultants Group ("MCG"), has been engaged by DBEDT to complete this review. The project team will be holding stakeholder workshops the week of October 9th on each island to speak with residents willing to share their thoughts on the future of electric utility ownership and the role the utility plays in achieving community and state goals, including achieving 100% renewable energy and minimizing rate increases.

These workshops are open to the public and we would welcome your participation and input. Additionally, we would appreciate any support you could offer in sharing this notice through your colleagues and networks to others who may be interested in attending.

The dates and locations of our public workshops are below. RSVPs are requested so we will be able to plan accordingly and provide updates about any changes in logistics.

Maui County:

- **Wailuku, October 9th, 5:30-7:00.** Wailuku Community Center, 395 Waena St. Event Flyer | RSVP Link
- **Kaunakakai, October 10th, 5:30-7:00.** Mitchell Pauole Center Main Hall, 90 Ainoa St. Event Flyer | RSVP Link
- **Lanai City, October 11th, 5:30-7:00.** Lanai Community Center, Eighth St and Lanai Ave. Event Flyer | RSVP Link

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- **Honolulu, October 13th, approx. 6:00 -7:30. Location still to be confirmed. Please RSVP for email updates.** Event Flyer | RSVP Link

Questions about the meeting or project can be directed to Len Trinidad, Project Manager, at cherrylin@londoneconomics.com.

13 Appendix G: Scope of work to which this deliverable responds

Task 1.2.4 Outreach Plan and documentation of results of public outreach on each island served by an electric utility. CONTRACTOR shall develop and carry out an outreach plan to solicit public input from each island currently served by an electric utility on the results of TASKS 1.1.1 through 1.2.3.

DELIVERABLE FOR TASK 1.2.4. CONTRACTOR shall provide its conclusions and all work to support an outreach plan for public input, designing and conducting outreach processes and activities with stakeholders, and incorporate feedback throughout the duration of the project as described in Proposal Scope Task 1.2.4. and submit a draft for STATE approval. Following approval, CONTRACTOR shall provide the final written Outreach Plan and documentation of results of public outreach on each island in MS Word and spreadsheets in MS Excel. CONTRACTOR shall submit deliverable for TASK 1.2.4 to the STATE for approval.

Ranking and Recommendation of Utility Ownership Models

Prepared for the Hawaii Department of Business, Economic Development, and Tourism (DBEDT) by London Economics International LLC and Meister Consultants Group

November 30, 2017

London Economics International LLC, together with Meister Consultants Group ("the Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State of Hawaii in achieving its energy goals. As part of the engagement, this working paper provides a ranking process and rationale for the recommendation four (4) feasible utility ownership models for further consideration. To rank each ownership model, the Project Team evaluated them according to the following criteria, per the project's scope of services: 1. support for state policy goals, 2. viability for utility finances, 3. transaction and implementation costs, 4. stability of rates, 5. operational risks, and 6. legal viability. The four feasibility models, ranked from highest to lowest, are the cooperative ownership model, the status quo, and the Single Buyer (outside the utility) model,

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List of acronyms

DBEDT	Hawaii Department of Business, Economic Development, and Tourism
DER	Distributed energy resource
FERC	Federal Energy Regulatory Commission
HECO	Hawaiian Electric Company
HEI	Hawaiian Electric Industries
HELCO	Hawaii Electric Light Company
IDER	Integrated distributed energy resource
IOU	Investment owned utility
IPP	Independent power producer
ISO	Independent System Operator
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International, LLC
MCG	Meister Consultants Group
MECO	Maui Electric Company
PUC	Public Utilities Commission
SB	Single Buyer

contact:
Ryan Cook / Bobby Kim
617-933-7200
ryan.cook@mc-group.com / bobby.kim@mc-group.com

1 Executive summary

London Economics International LLC, together with Meister Consultants Group (the "Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which corresponds to Task 1.2.5 in the project scope of work, provides a ranking of the ownership models introduced in Task 1 and further analyzed for high-level feasibility in Task 1.2.3. This Task seeks to recommend the four feasible ownership models for more in-depth analysis in subsequent Tasks.

One addition to the ownership models in this analysis was the categorization of the Single Buyer ("SB") model into two variants: the "inside the utility" model, in which the SB is part of the utility with appropriate ring-fencing from its other functions, and the "outside the utility" model, in which Hawaii State establishes an independent institution to take on the role of SB. Moreover, the New Parent model was divided into two variants: the "traditional" IOU New Parent, and a New Parent that adheres to B-Corp certification.

To implement this ranking, the Project Team distilled its research from previous tasks into major criteria for evaluating the ownership models. The Project Team then developed minor criteria to define these major criteria and evaluated, through the scale of "positive, neutral, and poor," the potential performance of the ownership models on each criterion, subject to certain assumptions. The major criteria include the following:

1. support for state policy goals;
2. viability of utility finances;
3. implementation costs;
4. stability of rates;
5. operational risks; and
6. legal viability.

Within these major criteria, the ranking weighted some minor criteria more heavily than others based on empirical data, the implications for achieving other criteria, the outcome of the stakeholder outreach held on October 9 to 13, 2017, and the fundamental expectations of the utility**.** The most heavily weighted minor criteria include (with the percentages of all minor criteria summing to 100%):

1. ability to meet state energy goals (10%);
2. consumer cost savings (10%);
3. aligning stakeholder interests (10%);
4. likelihood of increased rate volatility (10%);
5. reliability of service (10%) and;
6. likelihood of changes in regulation or legislation (10%).

From this ranking, **the analysis concludes that the top four most promising models are, with the highest score ranked first: (1) Cooperative, (2) Status Quo, (3) Single Buyer (Outside the Utility), (4) Single Buyer (Within the Utility)** . These are the ownership models that will be evaluated in the subsequent Tasks 1.3 and beyond. The least favorable three models were the grid defection model, the hybrid ownership (with majority government) model, and the traditional IOU under a new owner model.

One caveat with this ranking is that while it utilizes a numerical framework, these rankings are also based on some assumptions regarding the nature of the transaction and various characteristics of the regulatory environment, amongst others. It also tends to rely on a high-level analysis (Task 1.2.3.). The analyses in Tasks 1.3 to 1.6 of ownership models will further investigate and analyze the implications of these four ownership models.

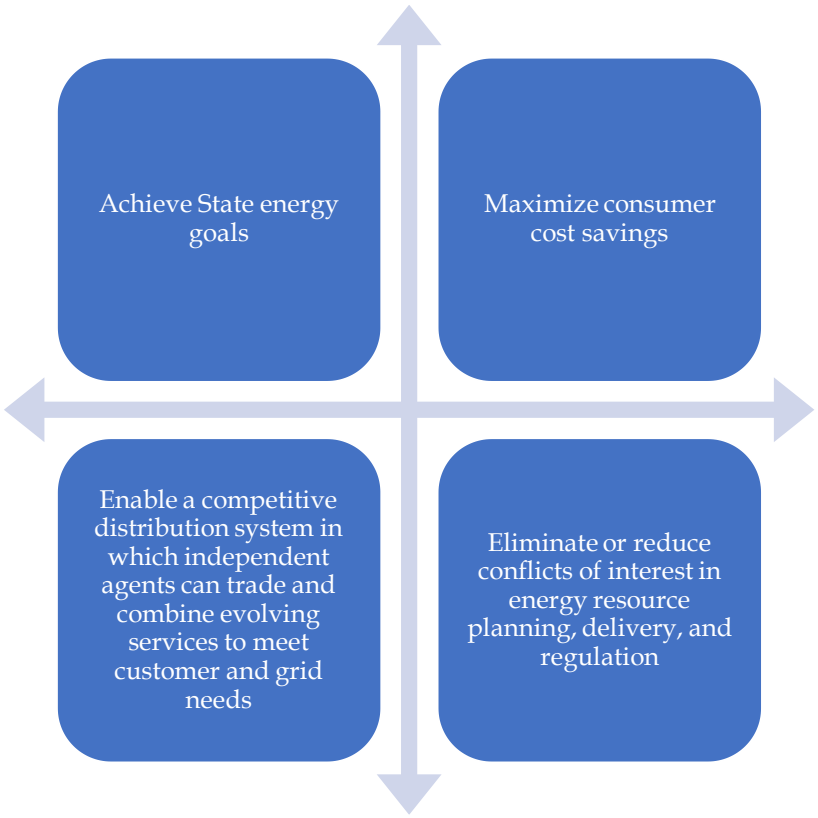
2 Introduction and scope

2.1 Project description

DBEDT was directed by the State's legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. The Project Team, through a competitive sealed proposals procurement,[1] was contracted to perform this study.[2]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[3] listed in Figure 1.

Figure 1. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

[1] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[2] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[3] House Bill No. 1700 Relating to the State Budget.

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[4]

2.2 Role of this deliverable relative to others in the project

This deliverable corresponds to Task 1.2.5 in the project scope of work. It builds on previous deliverables namely the introduction of the ownership models (Task 1.1.1.), high-level assessment based on the state goals (Task 1.2.1.), current market structure and system plans (Task 1.1.3. and 1.1.4.), potential stranded costs (Task 1.1.6.), and high-level feasibility of ownership models (Task 1.2.3.).

Moreover, the rankings in this deliverable take into account the stakeholder engagement efforts that occurred as a part of 1.1.1. (Kickoff Meeting), Task 1.2.4 (Community Discussions on Utility Ownership Models), and continual phone and online communication with public stakeholders. These stakeholder engagement efforts have framed and underscored the importance of key criteria that is reflected in our ranking design and weighting.

Finally, this task will serve as the precursor to further analysis in subsequent tasks:

- **Task 1.3.1. Identification of various steps, timeline, and costs required to change from the current ownership model to new models, including regulatory approvals.** This includes the required steps and associated costs, along with a projected timeline, to change the ownership model and acquire the electric generation, transmission and distribution plant (including substations) currently operated in each county, including all necessary approvals and/or permitting requirements.

- **Task 1.3.2. Identification of legal changes needed to implement the proposed utility legal framework options.** This includes an analysis of the legal framework of the ownership models and the changes to existing statute and regulations that are required for the change in ownership model. **Task 1.3.3. Identification of risk for each ownership model, analysis of each risk, and assessment of the overall risk profile for each ownership option.** The known or potential financial and operational risks and the bearer of those risks under each ownership model will be discussed in this task.

- **Task 1.3.4. Assessment of how each ownership model impacts staffing of State agencies and stakeholders.** This task will provide an estimate of the potential impacts a change in ownership model may have on the expertise and staffing requirements of related State agencies and stakeholders.

[4] Hawaii Contract No. 65595. Scope of Services.

- **Task 1.4. Economic Evaluation.** This includes an estimation of the book value for existing facilities, an economic evaluation of the ownership and operation of each ownership model, and an assessment of the management structure and staffing plan needs under each ownership model.

- **Task 1.5. Planning**. This includes an evaluation of the potential of each model to increase distributed energy resources, demand response programs, and RPS requirements, to name a few.

- **Task 1.6. Revenue and Financing.** This includes a discussion on how the revenue requirement is calculated under each ownership model, an analysis of how each ownership model would affect cash flows, an estimation of revenue requirements under each ownership model through 2045, a matrix comparing the system average retail rates under each ownership model, and an assessment of financing options.

3 Overview and Criteria

In this report, the Project Team describes its approach to evaluating and ranking the eight electric utility ownership models against a set of specific criteria. These eight ownership models include the following:

- Status quo (investment owned utility ("IOU") for HECO Companies and cooperative for KIUC);
- New parent under an investor-owned utility ("New Parent")
- Hybrid with majority government model ("Hybrid")
- Cooperative ("Co-op")
- Municipal ("muni")
- Single Buyer ("SB")
- Integrated Distributed Energy Resource System Operator ("IDER")
- Grid Defection

The objective of this exercise is to identify four highly-rated ownership models for further analysis in subsequent tasks.

3.1 Basis for Criteria and Major Evaluation Categories

Figure 2. Major and minor criteria

Major Category	Minor Category
Support for State policy goals	Ability to meet state energy goals
	Maximize consumer cost savings
	Enable a competitive distribution system
	Address conflicts of interest
	Align stakeholder interests (responsiveness to local community)
Viability for utility finances	Access to capital
	Costs of capital
Implementation costs	Likelihood to increase costs for change of ownership and operations
	Likelihood to increase regulatory oversight requirements
Stability of rates	Likelihood of increased rate volatility
Operational risks	Reliability of service
	Customer service quality
	Staffing expertise adequacy (includes leadership)
Legal viability	Likelihood of changing legislation and regulations or additional legal requirements
	Likelihood of legal challenges

The major evaluation categories used by the Project Team include support for State policy goals, viability for utility finances, implementation costs, the stability of rates, operational risks, and legal viability as shown in Figure 2. Most of these criteria are based on the scope of services. These criteria will be discussed in detail below.

3.1.1 Support for State Policy Goals

Each ownership model was scored based on its ability to help the State achieve its policy goals. These State policy goals were established by the legislation in House Bill 1700, which provided the directive for this Study. These study criteria, introduced in Task 1.2.1., include:

1. achieve state energy goals;
2. maximize consumer cost savings;
3. enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer needs; and
4. eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation.

To further inform and clarify the first objective above, "achieve state energy goals" has been interpreted as the combination of the State of Hawaii's 100% renewable energy target as well as the five Energy Policy Directives of the HSEO, which include:[5]

1. diversifying Hawaii's energy portfolio;
2. connecting and modernizing Hawaii's grids;
3. balancing technical, economic, environmental, and cultural considerations;
4. leveraging Hawaii's position as an innovation test bed; and
5. promoting an efficient marketplace, that benefits producers and consumers.

3.1.2 Viability of Utility Finances

The second criterion is the viability of utility finances, which is defined regarding the following minor categories:

1. access to capital; and
2. the costs of capital for each of the utility models.

Access to capital considers the constraints that each ownership model might impose on the types of capital it can access. For example, this could result from intrinsic characteristics of each ownership model (i.e., sole government ownership in the muni model) or effects of the ownership

[5] Hawaii State Energy Office, Hawaii Department of Business, Economic Development, and Tourism, "Energy Policy Directives," March 2017, available at: https://energy.hawaii.gov/wp-content/uploads/2011/08/EnergyPolicy_1pgr_rev-Mar2017.pdf.

model on segments of the electricity market (i.e., greater competition in generation in the IDER or SB models).

Costs of capital considers the unique advantages or disadvantages that each of the ownership models might have in terms of raising capital with respect to the current market-based rates for utilities.

3.1.3 Implementation Costs

Implementation costs are categorized into two minor categories:

1. the likelihood to increase costs for a change of ownership and operations; and
2. the likelihood to increase regulatory oversight requirements.

In the former category, considerations include whether the ownership model changes the role of the utility, requiring the additional expenditure in capital investments and/or for operations, or significant costs associated with the transition to the new ownership model.

With regards to regulatory oversight requirements, the Project Team evaluates this metric solely through the lens of the Public Utilities Commission ("PUC"). It evaluates whether the PUC will need to develop new capacities to oversee the ownership model.

3.1.4 Stability of Rates

The stability of rates considers the electricity rate volatility for consumers that may result from a change in utility ownership. Some ownership models may require regulatory changes (for example, in the IDER model), and these regulatory changes may lead to greater rate volatility. Rates could also change drastically between rate cases, even without a significant change in regulation. For instance, rates could rise if the revenue or costs for utilities change significantly due to market dynamics (for example, in the grid defection model). Such rate volatility would impact certain consumer segments more so than others.

3.1.5 Operational Risks

The operational risks are divided into three minor categories, namely:

1. reliability of service;
2. customer service quality; and
3. staffing expertise adequacy.

The first two standards of reliability of service and customer service quality are core responsibilities of any electric utility and are guided by PUC standards in Hawaii. The Project Team assesses if the transition to another ownership model will positively or negatively impact the reliability of the service and customer service quality. Ownership models that the Project Team think would be able to provide reliable service and good customer service are rated high in this criterion.

With regards to staffing expertise, this category touches on the sustainability of the workforce and intellectual capital within the utilities over both the short-term and the long-term. While generally it is a reasonable assumption that there will be a transition plan between ownership models that transfers human resources, some models will require entirely new capabilities, and thus will be subject to greater operational risk. Other models may have restrictions or limitations on how they can hire and retain qualified individuals.

3.1.6 Legal Viability

Legal viability assesses the overall legal feasibility of the ownership model and its transition. The Project Team evaluates this aspect regarding the following minor categories:

1. the necessity of changing legislation and regulations or additional legal requirements; and
2. the likelihood of legal challenges.

The first criterion related to changes in legislation, regulations, or additional requirements assesses the extent to which the involvement of various fora – whether it be the State legislature, local city councils, or the PUC – is necessary for the establishment of the ownership model. If current legislation and regulations are already in place, the ownership model scores high in this criterion.

The second category of "legal challenges," in contrast, aims to assess the likelihood of stakeholders or interveners challenging the proposed change in ownership model before the PUC or the courts.

4 Methodology

The Project Team developed its ranking by first establishing "major categories" by which to evaluate ownership models. Following this, the Project Team developed "minor categories," or sub-criteria, that would define the scope and meaning of such major categories. The Project Team then established a weighting system to indicate the relative importance of each of the minor categories. Finally, the Project Team evaluated existing data, literature, case studies, interviews, and insights gathered from stakeholder workshops, to determine the final weighting and scoring of the ownership models. Many of these insights were presented in Task 1.2.3, which provided an initial high-level feasibility overview of each of the ownership models, and Task 1.2.4, which provided the results of the Stakeholder Outreach.

The Project Team based its analysis on the ownership models introduced in Task 1.1.1/1.2.1, with some minor modifications to differentiate possible variations within each model. For the New Parent model, the Project Team divided the New Parent into a traditional IOU new parent, as well as a B-Corp new parent, to reflect feedback from stakeholders as well as the introduction of this model during the proposed NextEra acquisition.[6] The Project Team also distinguished the SB model into the "inside" model, where the SB is still part of the utility but ring-fenced from its other functions and physically separated from the utility and the "outside" model, where the State establishes a separate independent SB, which is outside of the utility.

This ranking analysis assigns each of the minor categories a score of 1, 2, or 3. 1 indicates a "poor" score, 2 indicates a "neutral" score, and 3 indicates a "positive" score. The scores are based on the results of prior analyses such as Task 1.2.1 (State Factors), Task 1.1.5 (Infrastructure Needs), Task 1.1.6 (Stranded Costs), and Task 1.2.3 (Technical, Financial, and Legal Feasibility), as well as the results of the stakeholder outreach conducted from October 9-13, 2017, and bilateral meetings with the key stakeholders.

Nevertheless, the Project Team acknowledges that each model's performance on some criteria may be subject to variability that is outside the scope of the ownership model but nonetheless informs the ownership model's transition or context. Examples of this could include the outcomes of the negotiated transaction or the accompanying regulatory context. In cases where it is both realistic and appropriate, the Project Team has clearly outlined all accompanying assumptions for its scoring. In cases in which there is significant variability and plausible leeway over these factors, the Project Team typically defaults to a "neutral" score to not unduly punish or promote any model unfairly.

[6] See Testimony and Exhibits of Ian Chan Hodges, "Division of Consumer Advocacy's Direct Testimonies and Exhibits," Division of Consumer Advocacy, Docket No. 2015-0022, August 10, 2015, https://cca.hawaii.gov/dca/files/2015/08/2015-0022-CA-DT-and-Exhibits-PUBLIC.pdf

Figure 3. Weighting of Minor Categories

Major Category	Minor Category	Weight
Support for State policy goals	Ability to meet state energy goals	10.0%
	Maximize consumer cost savings	10.0%
	Enable a competitive distribution system	2.5%
	Address conflicts of interest	5.0%
	Align stakeholder interests (responsiveness to local community)	10.0%
Viability for utility finances	Access to capital	5.0%
	Costs of capital	5.0%
Implementation costs	Likelihood to increase costs for change of ownership and operations	5.0%
	Likelihood to increase regulatory oversight requirements	5.0%
Stability of rates	Likelihood of increased rate volatility	10.0%
Operational risks	Reliability of service	10.0%
	Customer service quality	2.5%
	Staffing expertise adequacy (includes leadership)	5.0%
Legal viability	Likelihood of changing legislation and regulations or additional legal requirements	10.0%
	Likelihood of legal challenges	5.0%
Summary of major categories	Support for state policy goals	37.5%
	Viability for utility finances	10.0%
	Implementation costs	10.0%
	Stability of rates	10.0%
	Operational risks	17.5%
	Legal viability	15.0%

For the weighting, the Project Team also considered the perspectives of stakeholders gathered through various project tasks in this ranking. This includes Task 1.1.1, which includes the initial kick-off meeting held at the Hawaii Verge conference in June 2017 and accompanying bilateral discussions. It also includes Task 1.2.4, which includes subsequent stakeholder engagement workshops in October 2017 on each island and additional bilateral discussions. In addition, the Project Team also received significant feedback through online submissions that are also reflected in the weighting and rankings of this methodology. Furthermore, the weightings are in line with

the priorities of the PUC based on Inclinations and Guidance for any future merger or acquisition proceedings.[7] Figure 3 illustrates the weighting of the minor criteria.

The rationale for weighting certain criteria with greater importance in the overall ranking are as follows:

- **Ability to Meet State Policy Goals (10%):** The State Energy Policy Directives contain a variety of initiatives, each of which holds significant importance in achieving Hawaii's broader economic and environmental goals. Moreover, the objective of reaching a 100% Renewable Portfolio Standards ("RPS") by 2045 is of immense significance to the stakeholders in Hawaii, as was self-evident from the Project Team's discussions with stakeholders and their commitment towards that goal. Lastly, the Commission Guidance for any Future Merger or Acquisition proceedings stated that achievement of the State's clean energy goals is one of the six key areas that the acquiring utility should be able to comply with. More specifically, the PUC stated that "any future applications should provide clarity on the applicant's positions on clean energy transformation and distributed energy resources with a clear affirmation of the Commission's guidance on these areas in the Inclinations and relevant subsequent related decisions."[8]

- **Consumer cost-savings (10%):** The ranking emphasizes the importance of consumer cost-savings because of the unanimity and prevalence of stakeholder feedback for accounting for this metric. Moreover, Hawaii possesses the highest electricity rates in the United States.[9] Finally, this factor is also relevant to PUC regulatory decision-making for any potential transition in utility ownership, suggesting that it informs the feasibility of implementation as well.[10]

- **Aligning stakeholder interests (10%):** Responsiveness to the concerns of local stakeholders and communities are ranked highly to reflect the stakeholder feedback received during the engagement efforts of the Project Team. It also reflects the dynamics revealed during the proposed NextEra merger; any future ownership model change must address the interests and concerns of stakeholders to be acceptable to the Consumer Advocate, local municipalities, and the PUC.

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[7] Hawaii Public Utilities Commission, "Exhibit A: Commission's Inclinations on the Future of Hawaii's Electric Utilities," Docket No. 2012-0036, Decision and Order No. 32052, filed on April 28, 2 014, ("Order No. 32052"), available at https://puc.hawaii.gov/wp-content/uploads/2014/04/Commissions-Inclinations.pdf

[8] Hawaii Public Utilities Commission, *Order No. 33795 (Dismissing Application Without Prejudice and Closing Docket)*, Appendix A. P. 9. available at: https://puc.hawaii.gov/wp-content/uploads/2016/07/FINAL.ORDER_.33795.Docket2015-0022.pdf.

[9] Energy Information Administration, State Electricity Profiles, January 17, 2017, available at: https://www.eia.gov/electricity/state/.

[10] See Appendix A, Subsection A on "Ratepayer Benefits," Hawaii Public Utilities Commission, *Order No. 33795 (Dismissing Application Without Prejudice and Closing Docket)*, available at: https://puc.hawaii.gov/wp-content/uploads/2016/07/FINAL.ORDER_.33795.Docket2015-0022.pdf.

- **Likelihood of increased rate volatility (10%):** Like consumer cost savings, the ranking emphasizes rate volatility because of the unanimity and prevalence of stakeholder feedback for accounting for this metric. Furthermore, the PUC stated that "the consumers should be insulated from bearing costs resulting from the change of control, transition, and integration implementation."[11] Therefore, this is an important criterion that merits a higher weighting.

- **Reliability of service (10%):** Reliability of service has a significantly higher weighting since it is the core function of the electric utility. The scoring of other metrics, to a certain degree, already assume that the utility model under consideration can reliably provide service.

- **Likelihood of changes in regulation or legislation (10%):** The ranking emphasizes where changes in regulation and legislation are necessary for the ownership model. This is because the implementation of these changes is typically a prerequisite for all other effects of the ownership model under consideration.

Some of the factors, such as increasing the competitiveness of the system and customer service quality had the lowest weighting. This does not mean that they are unimportant.

[11] Hawaii Public Utilities Commission, *Order No. 33795 (Dismissing Application Without Prejudice and Closing Docket)*, Appendix A. P. 3. available at: https://puc.hawaii.gov/wp-content/uploads/2016/07/FINAL.ORDER_.33795.Docket2015-0022.pdf.

5 Ranking results

The following sections summarize the rationale for the scores of each of the ownership model on the minor criteria.

5.1 Support for State Policy Goals

- For the **State energy goals**, the Project Team's analysis concludes that **all the models, except for grid defection, would be able to achieve the state energy goals,** provided that certain conditions and assumptions are met, such as sound implementation and regulation. As discussed in the other working papers, these ownership models can be made to meet most, or all the state objectives and they differ in terms of effectiveness and the extent of regulatory intervention required. The only model that would clearly not be able to achieve the state energy goals is grid defection, due to its effects on utility finances, which subsequently affect the utility's ability to invest in clean energy generation and infrastructure that would support distributed energy resources ("DERs"), undermining diversity in resources and grid modernization.

- **Consumer Savings**

Ranking	Description
Positive	Incentivizes customer savings
Neutral	No discernable impact
Poor	Reduces consumer savings

The SB models rank positively. This is for several reasons: 1) the SB's sole purpose is to procure long-term energy at the least cost; 2) the ring-fencing of the incumbent generation assets from transmission and distribution assets would encourage efficiency in generation investments, which would respond to needs identified by the buyer; 3) the establishment of an independent single buyer outside the incumbent utility would incentivize more streamlined and effective procurement processes, generally fostering competition.

Grid defection is ranked poorly, due to the significant rate impact that this model would have on the rates for the remaining utility customers. More specifically, grid defection would result in a substantial increase in costs for remaining utility customers.

All other models are ranked as neutral. For the co-op model, the utility can share surpluses with its members although there is the possibility that the co-op management may not always pursue long-term least-cost initiatives because the co-op's priorities are driven by its members-consumers' interests, and these might not always be the least cost.

- **Enabling a Competitive Distribution System**

Ranking	Description
Positive	Encourages competition in energy services
Neutral	No discernable impact
Poor	Discourages competition in energy services

Both the IDER and SB models rank positively. In the case of the IDER model, the envisioned model effectively captures a broad and diverse range of value streams and services from DERs. This, by necessity, would imply greater competition in generation, particularly at the distribution level. The SB model would similarly encourage greater competition in generation by its procurement model and independent procurement of generation assets. **The grid defection model is also ranked positively here**, because it is directly associated with increased implementation and competition of DERs.

All other models are ranked as neutral, primarily because they would not have any discernable impact on competition, if all other variables are held constant.

- **Reducing Conflicts of Interest in Energy Resource Planning, Delivery, and Regulation**

Ranking	Description
Positive	Separates conflicts of interest in planning and operational control from investment and ownership
Neutral	No discernable impact
Poor	Leads to conflicts of interest in planning and operational control with investment and ownership

The SB (outside the utility) model, IDER, and the co-op model rank positively, since they have no direct incentives to increase investments**.** This is due to the independence of the SB model, generation, and procurement. This also assumes that dispatch is coordinated by an independent entity. Similarly, the IDER model ranks positively because of divestment by the utility of generation assets and the establishment of an independent ISO-like institution. The co-op model ranks positively on conflict of interest due to its customer-owner model of ownership.

For conflicts of interest, the **status quo** (in which KIUC, a cooperative, operates on Kauai Island and the HECO Companies, an IOU, operates on the remaining islands)**, the IOU model, and the hybrid model rank poorly.** The hybrid model ranks poorly due to the potential conflicts in interest between the private sector and governmental co-owners, as private sector investors are assumed to favor utility decisions that favor maximum shareholder returns while government investors are assumed to favor decisions that further state policy goals. Similarly, the Status Quo and the IOU model rank poorly as the utility's returns are tied to its investments. The utility is incentivized to increase its investments, rather than potentially pursue other options.

- **Aligning Stakeholder Interests**

Ranking	Description
Positive	Aligns with interests of local stakeholders
Neutral	No discernable impact
Poor	Contravenes the interests of local stakeholders

The co-op, muni, and IDER models rank positively. For the co-op and muni models, this is due to the influence that the consumers would have in terms of the direction of the utility. Therefore, the interests of the consumers would most likely be aligned with that of the utility. In the case of the co-op, the consumers have a say with regards to the decisions of the co-op management through voting and electing the members of the Board. In the case of the municipal model, ratepayers can influence the decisions of the utility through electing the local officials, who then elect the board members of the utility. In the case of IDER, consumers are empowered to not simply be consumers of energy, but producers as well, due to the markets established by monetizing various value streams from DERs.

For aligning stakeholder interests, **the grid defection model ranks poorly.** This is because of the impact that grid defection would have on lower-income households in terms of rising electricity costs and arguably decreasing reliability. It would also harm the ability of the utility to continue operating in a financially sustainable manner.

All other models rank neutral. As the incumbent model for much of the state, the status quo IOU model is assessed as having a neutral baseline rating. Whereas the co-op, muni, and IDER models can provide greater stakeholder responsiveness due to customer influence in some of the utility's decisions through the appointment of utility leadership or through market activity. Other models such as a new parent (either the B-Corp or the traditional investor new parent), hybrid ownership, and SB are not considered to provide a much greater degree of alignment with stakeholder interests than the status quo. While the new B-Corp parent would require the IOU to consider the impact of its decisions on stakeholders, it would continue to be a for-profit company governed by external investors, much like the status quo and a traditional new parent model. In these models, the continued presence of investor-owned infrastructure is expected to yield similar responsiveness to stakeholder concerns as the incumbent IOU model.

- **Access to Capital**

Ranking	Description
Positive	Increases avenues and attractiveness to capital markets
Neutral	No discernable impact
Poor	Constrains avenues for capitalization

The **Status quo, hybrid, B-Corp., SB, and traditional new parent models rank positively**. This is because of these models, in various fashions, have access to traditional capital markets.

- In contrast, the **muni and co-op models rank neutral.** As discussed in Task 1.2.3, co-ops have access to federal and cooperative programs while munis can utilize tax-exempt debt. Nevertheless, munis may be limited by municipal credit rating and bond capacity. Co-ops must qualify for certain financing programs and are subject to program rules and availability of capital. FMoreover, co-ops generally subordinate capital, so that those who contribute capital neither control operations nor receive most of the benefits. These two principles can limit interest from outside equity investors, though this is made up for by increased access to special federal and utility financing programs.. **Costs of capital**

Ranking	Description
Positive	Unique reductions in the cost of capital relative to the market rates of the status quo for incumbent utilities
Neutral	Rely primarily on status quo market rates
Poor	Unique risks or other major factors that raise the cost of capital

The **co-op and muni models rank positively.** The supporting rationale is that the co-op, subject to its classification as "rural," would be able to borrow funds at below-market rates for purchase and infrastructure improvements. Correspondingly, given the credit ratings of municipalities in Hawaii and the fact that munis can finance through tax-exempt bonds, it is not unreasonable to expect that the muni cost of capital would be lower than market rates. In all other models, financing would occur through market rates.

All other models rank neutral because they would continue to rely on market rates.

5.2 Implementation Costs

- **Likelihood of Increasing Costs from Change in Ownership and Operations**

Ranking	Description
Positive	Negligible costs from changes in ownership and operations
Neutral	Moderate costs of implementation from changes in ownership and operations
Poor	Major costs of implementation from changes in ownership and operations

For the likelihood to increase costs for a change of ownership and operations, **the status quo ranks positively**, due to the lack of changes or transition costs.

The **muni and the hybrid model rank neutral** since the systems are already in place, operations would largely remain the same, and the only aspect that would change is the ownership. There would be no additional infrastructure investment needed as discussed

in Task 1.1.4. For the muni model, the acquisition price paid to the utility would be based on the utility value, and do not include a market premium.

SB, IDER, and B-Corp rank poorly because these models would entail additional costs to set up the ring-fencing mechanisms (SB and IDER) as well as compliance with required metrics (for B-Corp).

Co-op and New Parent models also rank poorly as these models require the utility's agreement to purchase its assets, which presumably would entail offering a premium over market value.

- **Likelihood to increase regulatory oversight requirements**

Ranking	Description
Positive	No need for any PUC oversight
Neutral	The required PUC oversight approximates the status quo
Poor	PUC oversight requirements significantly increase relative to status quo

The muni and grid defection models rank positively because they require no regulation from the PUC (this assumes that the PUC would not regulate a municipal utility in Hawaii, which is the common regulatory practice in the United States).

All the other models, except for the IDER model, rank neutral because they would not drastically change the cost-of-service regulatory framework that has regulated the utilities (this assumes that a co-op would be regulated by the PUC – Hawaii is one of several states where co-ops comply with PUC rate regulation, though in many states, the PUC does not have authority over co-ops). In the case of the SB model, the PUC already regulates the procurement process of the incumbent IOUs as well as the power purchase agreements with the independent power producers ("IPPs") which would not be drastically different from its oversight role with the SB.

The IDER model ranks poorly because it would require an entirely distinct and unique regulatory framework and role for utilities to facilitate the DER services.

5.3 Stability of Rates

- **Rate Volatility**

Ranking	Description
Positive	Reduces factors for potential rate volatility
Neutral	Approximates the status quo of regulated rates
Poor	Increases factors for potential rate volatility

All the models rank neutral, except for the Grid Defection and IDER models, which rank poorly. The IDER model implies greater granularity in the valuation of energy across geography and time, suggesting that there may be more potential rate volatility to

communicate the cost of DERs in a granular fashion. Grid Defection may lead to more rapid rate changes for remaining utility customers to recover the cost of service.

5.4 Operational Risks

- **Reliability of Service**

Ranking	Description
Positive	Improves the potential reliability of electricity service
Neutral	Maintains the reliability of service, with plausible assumptions and considerations
Poor	Undermines the potential reliability of electricity service

All the models rank neutral on reliability on service except for grid defection, which ranks poorly. It is plausible and feasible for each of the ownership models to maintain reliable service with the assumption that they are accompanied with appropriate regulatory measures. It is also impossible to state definitively that one ownership model would perform better than others in this regard. Grid defection would undermine the ability of the utility to make the necessary improvements for maintaining grid reliability due to revenue losses from customers that defect from the grid.

- **Customer Service Quality**

Ranking	Description
Positive	Improves the ability of the utility to provide customer service
Neutral	Approximates the status quo of customer service
Poor	Reduces the ability of the utility to provide customer service

All the models rank neutral on customer service quality except for grid defection. It is plausible and feasible for each of the ownership models to provide good customer service. However, grid defection would undermine the ability of the utility to maintain customer service quality due to revenue losses and thus reducing its ability to hire and train staff to adeptly respond to customer concerns.

- **Staffing Expertise Adequacy**

Ranking	Description
Positive	Preserves the expertise of staff
Neutral	Expertise can be maintained easily and sufficiently
Poor	Serious challenges in maintaining the expertise of staff

The status quo ranks positively as the incumbent utility does not need to hire additional staff to ensure that the utility is running smoothly.

The traditional, B-Corp., hybrid, co-op, SB (inside), and grid defection models all rank neutral. Each of these models could plausibly inherit the existing expertise of the

incumbent IOUs with an appropriate transition plan, and they could maintain such expertise over the long run.

The muni, SB (outside), and IDER models all rank poorly. Even with an appropriate transition plan, the muni model encounters difficulties in retaining expertise over the long run due to civil service restrictions and the challenge of collective bargaining agreements. The SB (outside) model suggests that the State would have to hire a cohort of professionals to run its independent SB model, unlike the SB (inside) model, in which internal experts to the incumbent utilities will run the SB. Likewise, the IDER model suggests that the State would have to hire people with certain expertise to run an ISO-like institution in a rapidly developing field.

5.5 Legal Viability

- **Likelihood of changing legislation and regulations or additional legal requirements**

Ranking	Description
Positive	Requires no regulatory or legislative action
Neutral	Requires regulatory action but no legislative action
Poor	Requires both regulatory and legislative action

The status quo and grid defection models rank positively. There is no additional legislation or regulatory action necessary to implement these models.

The traditional IOU, B-Corp., and co-op models rank neutral. Such an acquisition would presumably undergo the regulatory scrutiny of the PUC but would require no additional legislative action to be implemented.

The hybrid, muni, SB, and IDER models all rank poorly. Each of these models requires legislative or city council action, either to establish the entities, raise funding, alter the regulations, or some combination of these actions, to transition to the new model successfully.

- **Likelihood of Legal Challenges**

Ranking	Description
Positive	Little risk of legal challenges from stakeholders
Neutral	Moderate risk of legal challenges from stakeholders
Poor	Major risk of legal challenges from stakeholders

The status quo ranks positively. It is assumed that maintaining the status quo would result in the lowest risk of stakeholder legal challenges, as the right of Hawaii's current utilities to operate is well established.

The SB, co-op, and grid defection models are ranked neutral. While there is a level of risk of significant legal challenge in any transition in utility ownership, this is expected to

be less severe for co-ops than for other forms of ownership given the precedent of co-ops in Hawaii already. Similarly, the stakeholders' negative reaction to the formation of a single buyer is expected to be less severe than others because there is no change in ownership of physical infrastructure under the SB (inside), only of utility roles and responsibilities. Grid defection is also rated as neutral because there is no structured change in legal ownership akin to a utility acquisition for stakeholders to raise the challenge.

The new parent, hybrid, muni, and IDER rank poorly because these would entail a sale of the utility's assets to utility ownership types that are not yet present in Hawaii. Similar to the failed NextEra acquisition, such an acquisition – whether it be by a corporate entity, B-corporation, or government entity and whether it be for all utility assets or restricted to generation assets - would likely be subject to significant opposition from various stakeholders.

6 Recommended ownership models

The Project Team's analysis identified the top four ownership models that will be further evaluated in the Tasks 1.3 to 1.6. These four models, in order of ranking, are 1) the Co-op model, 2) the Status Quo (that is, an IOU for the majority of the state, with a co-op on Kauai), 3) the Single Buyer (Outside the Utility), and 4) the Single Buyer (Under the Utility). The detailed scores for each model and the results of the ranking analysis are illustrated below in Figure 4.

Figure 4. Conclusions of the Ranking Analysis

Major Category	Minor Category	Weight	IOU (status quo)	New Parent		Hybrid	Coop	Muni	IDER	Single Buyer		Grid Defection
				Traditional	B-Corp					Under utility	Outside utility	
Support for State policy goals	Ability to meet state energy goals	10.0%	2	2	2	2	2	2	2	2	2	1
	Maximize consumer cost savings	10.0%	2	2	2	2	2	2	2	3	3	1
	Enable a competitive distribution system	2.5%	2	2	2	2	2	2	3	3	3	3
	Address conflicts of interest	5.0%	1	1	2	1	3	2	3	2	3	2
	Align stakeholder interests (responsiveness to local community)	10.0%	2	2	2	2	3	3	3	2	2	1
Viability for utility finances	Access to capital	5.0%	3	3	3	3	2	2	2	3	3	1
	Costs of capital	5.0%	2	2	2	2	3	3	2	2	2	2
Implementation costs	Likelihood to increase costs for change of ownership and operations	5.0%	3	1	1	2	1	2	1	1	1	1
	Likelihood to increase regulatory oversight requirements	5.0%	2	2	2	2	2	3	1	2	2	3
Stability of rates	Likelihood of increased rate volatility	10.0%	2	2	2	2	2	2	1	2	2	1
Operational risks	Reliability of service	10.0%	2	2	2	2	2	2	2	2	2	1
	Customer service quality	2.5%	2	2	2	2	2	2	2	2	2	1
	Staffing expertise adequacy (includes leadership)	5.0%	3	2	2	2	2	1	1	2	1	2
Legal viability	Likelihood of changing legislation and regulations or additional legal requirements	10.0%	3	2	2	1	2	1	1	1	1	3
	Likelihood of legal challenges	5.0%	3	1	1	1	2	1	1	2	2	2
Summary of major categories	Support for state policy goals	37.5%	**0.7**	**0.7**	**0.8**	**0.7**	**0.9**	**0.9**	**0.9**	**0.9**	**0.9**	**0.5**
	Viability for utility finances	10.0%	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.2**	**0.3**	**0.3**	**0.2**
	Implementation costs	10.0%	**0.3**	**0.2**	**0.2**	**0.2**	**0.2**	**0.3**	**0.1**	**0.2**	**0.2**	**0.2**
	Stability of rates	10.0%	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.1**	**0.2**	**0.2**	**0.1**
	Operational risks	17.5%	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.3**	**0.3**	**0.4**	**0.3**	**0.2**
	Legal viability	15.0%	**0.9**	**0.5**	**0.5**	**0.3**	**0.6**	**0.3**	**0.3**	**0.5**	**0.5**	**0.8**
Combined Score	**Score**	**N/A**	**0.54**	**0.45**	**0.47**	**0.43**	**0.55**	**0.49**	**0.48**	**0.52**	**0.53**	**0.38**
	Rank	**N/A**	**2**	**8**	**7**	**9**	**1**	**5**	**6**	**4**	**3**	**10**

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It is also interesting to note that even if the Project Team had applied even weights (at 6.66% each) for all the minor categories, the ranking would remain the same.

6.1 Co-op

The highest-ranking utility model in this analysis is the co-op. Pointing to the establishment of KIUC, many stakeholders have expressed support for establishing a similar co-op system on each of their islands. In contrast to the status quo, the co-op model is perceived to be better at aligning stakeholder interests because the consumers are also the owners and it eliminates the "profit" motive inherent to IOUs. Moreover, the co-op has access to lower cost debt financing, when compared to the typical market rate for utilities. However, a transition to the co-op model beyond Kauai would likely require a significant debt-based purchase from the incumbent utility, which may have long-term impacts on ratepayers. Additionally, since co-op leaders are democratically elected by members, the strength of leadership may vary based on the outcomes of these elections.

6.2 Status Quo

The second highest ranking utility model in this analysis is the preservation of the Status Quo, in which KIUC continues to operate as a co-op on Kauai, and HEI continues to operate the HECO Companies on the remaining islands. Clearly, this model benefits from the mere fact that it faces little challenges regarding legal viability and other implementation costs. Moreover, these incumbent utilities have also been successful in meeting the responsibilities of an electric utility as outlined by the PUC. The downside of the Status Quo is that it does not address the serious concerns raised by stakeholders that the HECO Companies serve their shareholders' interests, rather than stakeholders' interests.

Ultimately, it will be necessary to demonstrate measurable benefits for stakeholders from alternative ownership models over the Status Quo before suggesting any change. Also note that upholding the status quo in ownership models, does not necessarily entail the continuation of the status quo in regulatory models, which will be the subject of Task 2 in this project.

6.3 Single Buyer (Outside of the utility)

The third highest ranking utility model in this analysis is the independent single buyer that is outside of the utility model, which is distinguished from the "utility" single buyer model variant, in that the SB is not only ring-fenced from the other business entities of the utility but is outside of the utility.

This model rates highly because of its potential value in addressing several perceived deficiencies of the incumbent utility, such as a conflict of interest within utility operations, fair conduct of the procurement process, independent energy and capacity planning. Described in broad strokes, the SB's role is to procure energy for the long term at least costs, which potentially will help in optimizing the consumer cost savings and generating competition for contracts.

6.4 Single Buyer (Within the utility)

The fourth highest ranking utility model in this analysis is the single buyer that is "within" the incumbent utility. In this case, the single buyer, while owned by the incumbent utility, is

otherwise ring-fenced from the functions of the existing utility in terms of legal status, financial accounts, and operations. This includes separated buildings, branding, employees, and information technology systems.

Like the "outside" single buyer model, this model rates highly because it can address perceived deficiencies of the incumbent utility, such as conflicts of interest within utility operations and the fairness of procurement and planning processes. It is also focused on procuring energy at least cost. Unlike the "outside" single buyer, the SB can draw more readily from existing utility staff and expertise; however, it is consequently subject to a greater risk of conflicts of interest that undermine the mission of the single buyer.

7 Appendix A: Scope of work to which this deliverable responds

Task 1.2.5 Ranking process and rationale for the recommendation of three feasible utility ownership models.

CONTRACTOR shall identify and recommend three feasible ownership models for further consideration. CONTRACTOR should recommend options for the governance structure under each of these ownership models.

DELIVERABLE FOR TASK 1.2.5. CONTRACTOR shall provide its conclusions and all work to support aggregating all of the research and analysis in Tasks 1.1 and 1.2 to make recommendations for the three most beneficial utility ownership models for further consideration. CONTRACTOR shall provide an analytical framework of five to six criteria to rank each ownership model, including, but not limited to, support for state policy goals, viability for utility finances, stable rates, operational risks, legal viability or others as agreed upon with STATE. Analysis shall include ranking scores for each of those criteria to ensure that the assessment is based on objective, pre-determined criteria, and an aggregate score for each ownership model for ranking. CONTRACTOR shall provide a written narrative in MS Word and MS Excel tables showing the ranking and rationale for the score for each criteria used in the assessment and a ranking of the ownership models by aggregate score. CONTRACTOR shall submit deliverable for TASK 1.2.5 to the STATE for approval.

8 Appendix B: List of works consulted

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The Steps, Costs, Timeline, Legal Changes, and Risks for Establishing the Cooperative and Single Buyer Utility Models

Working paper prepared by London Economics International LLC for the State of Hawaii with support from Meister Consultants Group, a Cadmus Company

December 17, 2018

London Economics International LLC, together with Meister Consultants Group, a Cadmus Company ("the Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State achieve its energy goals. As part of the engagement, this working paper provides a discussion of costs, steps, legal considerations, and risks for the four highest ranked ownership models from Task 1.2.5 (listed from the highest to lowest rank): The Cooperative model, the status quo, the single buyer external to the utility, and the single buyer within the utility. These tasks respectively correspond with Task 1.3.1, 1.3.2, and 1.3.3 of the study. To assess the costs, the Project Team evaluated potential acquisition costs, start-up costs, and operating costs. To describe the steps, the Project Team reviewed existing literature on these ownership models, outlined the key tasks involved for each model, and estimated the time necessary for individual steps for establishment and operation. For legal considerations, the Project Team researched the legal requirements and legal changes for the establishment, funding, and operation of each ownership model. Finally, the Project Team describe the likelihood and magnitude of the financial, business, macroeconomic, operational, and governance risks for each ownership model.

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List of acronyms

ASB	American Savings Bank
B	Billion
CEO	Chief Executive Officer
CFC	Cooperative Finance Corporation
CY	Calendar Year
D/E	Debt/equity ratio
DBEDT	Department of Business Economic Development, and Tourism
DCF	Discounted Cash Flow
DER	Distributed Energy Resource
D&O	Decision & Order
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortization
ECAC	Energy Cost Adjustment clause
ECTSF	Electricity Conservation and Supply Task Force
EPS	Earnings Per Share
EV	Enterprise Value
FASB	Financial Accounting Standards Board
FY	Fiscal Year
GAAP	Generally Accepted Accounting Principles
HAR	Hawaii Administrative Rules
HB	House Bill
HECO	Hawaii Electric Company
HEI	Hawaii Electric Industries
HELCO	Hawaii Electric Light Company
HIEC	Hawaii Island Energy Cooperative

HRS	Hawaii Revised Statutes
IPP	Independent Power Producer
IRC	Internal Revenue Code
IRP	Integrated Resource Planning
IRS	Internal Revenue Service
ISO	Independent System Operator
KE	Kauai Electric
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International
M&A	Mergers and Acquisitions
MCG	Meister Consultants Group, a Cadmus Company
MECO	Maui Electric Company
MM	Million
MWh	Megawatt-hour
NRECA	National Rural Electric Cooperative Association
OPA	Ontario Power Authority
P/E	Price/Earnings
PACOM	U.S. Pacific Command
PG&E	Pacific Gas and electric
PPAC	Purchase Power Adjustment Clause
PREPA	Puerto Rico Electric Power Authority
PSIP	Power Supply Improvement Plan
PV	Photovoltaics
PUC	Public Utilities Commission

PURPA	Public Utility Regulatory Policies Act
RE	Renewable energy
RFP	Request for Proposals
RUS	Rural Utilities Service
S&P	Standard and Poor's
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
T&D	Transmission and Distribution
TNB	Tenaga Nasional Berhad
TTM	Trailing Twelve Months
USC	United States Code
USDA	U.S. Department of Agriculture

1 Executive summary

In Task 1.2.3 and 1.2.5, the Project Team provided a high level overview of the legal, technical, and financial feasibiltiy of eight ownership models and ranked them according to those criteria. The four highest ranking models from this analysis in order from highest to lowest rank were the *Cooperative* (*co-op), the status quo, the single buyer (outside the utility), and the single buyer (inside the utility).* Definitions of each of these ownership models are outlined in each of the "key conclusions" paragraphs below. In this subsequent working paper intended to cover Task 1.3.1, 1.3.2, and 1.3.3, the Project Team analyzes each of these ownership models with regards to the following topics:

- The steps, timeline, and costs required to change and establish the model;
- Legal steps or changes necessary to implement the proposed utility legal framework; and
- Financial, business, macroeconomic, operational, and governance risks. For the risks, the Project Team categorizes such risks in terms of its overall *impact* and *probability* in tiers of low, low-medium, medium, medium-high, and high.

The status quo ownership model is characterized by a co-op model on Kauai Island (the Kauai Island Utility Cooperative [KIUC]), and investor owned utilities (IOUs) on the other islands (the Hawaii Electric Company [HECO], Hawaii Electric Light Company [HELCO], and Maui Electric Company [MECO], collectively referred to as the "HECO Companies"). Note that the Project Team evaluates the risks of the status quo model only in terms of the incumbent IOUs, since the Project Team evaluates the risks of the co-op model separately. The key conclusions for the status quo ownership model include the following:

- The status quo ownership model, by definition, requires *no costs*, *no steps*, and *no legal changes.* In effect, the status quo preserves the co-op model in Kauai county and an investor owned utility (IOU) for the other counties.

  However, the preservation of the status quo in terms of ownership does not necessarily entail the preservation of the status quo in terms of regulation. Changes in utility regulation may help ensure that the utilities meet State energy goals; the Project Team will explore these potential regulation changes in Task 2 of the project.

- In terms of potential risks, the utility bears medium probability of *credit risk*[1] (given national trends in credit ratings for IOUs, co-ops, and the single buyer models), medium

[1] Credit risk is defined as "the risk of default on a debt that may arise from a borrower failing to make required payments." The project team defines the *impact* of credit risk as "high."

probability of *competitive risk*[2] (due to the possibility of retail and distribution competition), and medium-high probability of *regulatory risk*[3] (since relative to co-ops, IOUs are under a greater regulatory oversight).

However, the status quo bears relatively low-medium probability of *management risk*[4] and medium probability of *labor availability risk*,[5] since unlike the co-op or single buyer models, the model requires no changes to management and no transitioning or hiring of personnel.

The co-op model is defined as a scenario in which Hawaii ratepayers within a certain geographical area of coverage would form a nonprofit that would take ownership of the utility assets of the HECO Companies. As previously noted, a co-op model is already in place on Kauai Island, and a registered co-op entity exists on Hawaii Island (the Hawaii Island Energy Cooperative, or "HIEC"). The key conclusions for the co-op model[6] include the following:

- The *timeline* of the establishment of the co-op is approximately *24-36 months*. The longest steps of this timeline are the *regulatory approval*, and the *funding, negotiation, and purchase* of assets, which are codependent steps. Historically, final decision and orders (D&Os) on regulatory proceedings alone regarding a transfer in utility ownership have spanned up to 18 months from the initial application.

- The *costs* of establishing the co-op model are primarily constituted by the acquisition cost. Based on an analysis of trading comparables and transaction comparables, the Project Team estimates that the cost of acquiring the HECO Companies could range from $4.1 billion to $4.9 billion dollars. In addition to these methodologies based on comparable trading and transactions, Task 1.6.2 and 1.6.3 will provide an additional valuation of the utilities in Hawaii through a discounted cash flow (DCF) analysis.

  An additional component of the total acquisition cost includes transaction fees, which include legal, banking, and advisory services during the acquisition. Based on a limited sample of transactional fees associated with utility mergers and acquisitions activity, the

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[2] Competitive risk is defined as "the risk of a decline in a utility's competitiveness amongst other electric entities." The project team defines the *impact* of competitive risk as "high."

[3] Regulatory risk is defined as "risk of change in electricity rate regulation and its impact on the utility and its ratepayers." The project team defines the *impact* of regulatory risk as "high."

[4] Management risk is defined as "ineffective, destructive, or underperforming management, which can negatively impact the utility's efficiency, profitability, and/or credit rating." The project team defines the *impact* of management risk as "medium."

[5] Labor availability and skill risk is defined as "the lack of skilled labor to perform the necessary functions of the company." The project team defines the *impact* of labor availability and skill risk as "medium."

[6] These conclusions do not apply to the case of Kauai since the incumbent utility on the island is already a Cooperative.

Project Team estimates that such transaction fees will be approximately 1-2% of the acquisition cost, or $41 million to $98 million, depending on the size of the acquisition.

- As for *legal changes*, the existence of KIUC clearly illustrates that a prior legal framework exists for co-op establishment in Hawaii. No changes to regulation are necessary to establish the co-op; the burden of proof rests on the co-op to demonstrate that it can meet the laws and regulations already in place.

  In this respect, future co-ops will need to adhere to federal tax laws and state statutes to ensure that they qualify as a nonprofit and as a co-op. Such co-ops will also have to meet the standards outlined in federal statute that govern the provision of U.S. Department of Agriculture (USDA) Rural Utilities Service (RUS) funding. Finally, the acquisition must meet the reasonableness and public interest standards of the Public Utilities Commission (PUC), which are described in detail in the KIUC-Citizen's Communications acquisition and the proposed NextEra-Hawaii Electric Industries (HEI) Merger.

- In terms of its relative risk, the co-op model faces a medium-high probability *management risk* and a medium-high probability of *labor availability and skill risk*, since the co-op effectively undertakes all the responsibilities of the incumbent utility, entailing significant undertakings in transitioning the utility and hiring (or retaining) personnel. This rating is applied in comparison to a situation in which the status quo utility continues to operate, and so staff transition risks do not apply.

  The co-op model faces a medium probability of *regulatory risk*, given that co-ops are historically subject to less regulation from the Hawaii PUC relative to IOUs in the status quo and single buyer models, although its rates are still regulated. Moreover, the co-op would have a low probability of *credit risk*, given its access to various sources of low-cost financing. Finally, it would have a low-medium probability of *competitive risk*, since community control over the utility would presumably reduce the likelihood of distribution and retail competition.

The single buyer model is defined as an entity that possesses sole authority over the procurement and planning of energy resources in Hawaii from independent power producers (IPPs) and possibly the incumbent utilities. These functions – procurement and planning – are currently responsibilities of the incumbent utilities. Under the single buyer model, *all* new generation resources must undergo the single buyer procurement process, and the incumbent utilities must follow the planning undertaken by the single buyer. Moreover, the single buyer envisioned in this document is not responsible for system operation, such as dispatch, which remains the responsibility of the incumbent utilities.

The Project Team evaluated two different versions of the single buyer model. The Project Team first evaluated the "inside" single buyer that is still within the utility, but surrounded by appropriate ring-fencing mechanisms, which include separation of single buyer's operations and accounts from the incumbent's other business entities and limited or no sharing of information. Second, the Project Team evaluated the "outside" single buyer, which is an independent entity

outside of the utility, possibly as a government entity or a nonprofit. The key conclusions for the single buyer models include the following:

- A rough approximation of the *timeline* of the single buyer model is 48 months, with significant uncertainty due to the legislative and regulatory processes to establish the single buyer entity. These estimates are drawn from PUC docket proceedings on integrated resource planning[7] and competitive procurement, and legislative action on energy-related issues. The actual timeline of the single buyer for the "inside" or "outside" models could deviate significantly from these estimated timelines due to the novelty of the single buyer approach.

- The *establishment cost* of the single buyer model is also uncertain because Hawaii would be the first adopter of such a model in the United States. Based on the expenditures of a comparable single buyer model in Ontario, Canada, the Project Team estimates that the Year One costs of such a model would be approximately $2.9 million. The operating costs, or $2.3 million, of this total Year One cost is approximately one-third of the annual operating costs of the Hawaii PUC.

  Several caveats to this analysis suggest that this may be a low estimate of the total establishment cost. Such caveats include the relatively higher prices of goods and services in Hawaii as compared to Ontario, the exclusion of leasing/rental costs in Ontario's initial costs, and the likelihood that the costs of a single buyer may not scale in a linear manner according to total procurement needs.

  The costs of the "inside" and "outside" models are comparable. However, the "outside" model will require hiring additional personnel in finance, accounting, human resources and other general support services, and therefore may cost more than the "inside" single buyer, which would continue to rely on the in-house capabilities of the utility for administrative tasks.

- The *legal changes* required for the single buyer model are also uncertain due to the novelty of the model. Both the "outside" and "inside" single buyer models would require a PUC proceeding. The "outside" single buyer model will require legislative action to establish a new entity to undertake the planning and procurement responsibilities of the utility.

  In contrast, it is possible that the PUC could mandate the "inside" single buyer for the utility by revising the Codes of Conduct and Frameworks for competitive procurement and integrated resource planning,[8] with continued funding for the "inside" single buyer through periodic evaluation in rate cases. However, there are likely to be a range of

[7] "Integrated Resource Planning" in this context is intended to also include the Power Supply Improvement Plan processes.

[8] Although the details of the IRP are useful for the purposes of this analysis, it is evolving, and may be replaced by Integrated Grid Planning (IGP). *See*, Docket No. 2018-0165, Order No. 35569, Instituting a Proceeding to Investigate Grid Planning, filed on July 12, 2018.

scenarios (i.e. amendment of the franchise agreement or state funding) that would make legislative action necessary or prudent, even for the "inside" single buyer. Finally, the availability of certain bond offerings and the applicability of workforce regulations depend on whether the single-buyer entity is a public or non-profit entity and whether it will generate any revenue.

- In terms of relative risk, the "outside" single buyer faces high probability of *management risk* and a high probability of *labor availability and skill risk*, since the "outside" single buyer must not only establish and hire personnel for a new entity overseeing procurement and planning processes but will also be the first adopter of such a model in the United States. In contrast, the "inside" single buyer possesses a medium-high probability of management risk and medium labor availability and risk because existing utility resources and expertise can be leveraged for the "inside" single buyer model. The independence of the "outside" single buyer from the utility also contributes to a lower probability of *ownership and governance risk*[9] than the "inside" single buyer.

  Both single-buyer models have a medium-low probability of *credit risk*, or lower than a status quo IOU, assuming that the most creditworthy IPPs are more likely to secure generation contracts. Both single-buyer models, due to increased competition from IPPs, may also encourage higher asset quality in the incumbent IOU, leading to a medium-low probability of *asset quality risk.*[10]

In terms of a general comparison, the single-buyer approach is lower cost than the co-op (due to the entity undertaking a more limited set of responsibilities than the co-op), but possesses greater uncertainty in final cost, timeline, and necessary legal changes. In contrast, the co-op model comes at significantly higher cost, but requires no legal changes in Hawaii for implementation and possesses greater certainty in implementation. Both models possess some degree of management risk and labor availability risk. The status quo, of course, has no costs, required steps, or legal changes, but is accompanied by the risks of the incumbent IOU and co-op ownership structures.

[9] Ownership and governance risk is defined as "the risk of an inability to achieve company objectives due to poor ownership or governance structure." The project team defines the impact of ownership and governance risk as "high."

[10] Asset quality risk is defined as "the risk of the failure to upkeep assets and infrastructure to sufficient quality." The project team defines the *impact* of asset quality risk as "low-medium."

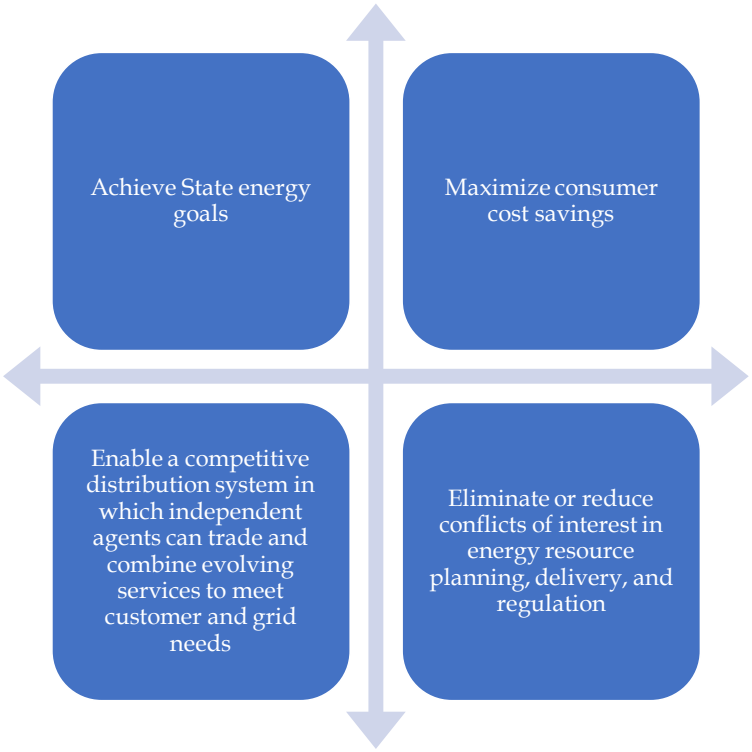
2 Introduction, scope, and structure

2.1 Project description

DBEDT was directed by the State's legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. The Project Team, through a competitive sealed proposals procurement,[11] was contracted to perform this study.[12]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[13] listed in Figure 1.

Figure 1. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

[11] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[12] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[13] House Bill No. 1700 Relating to the State Budget.

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[14]

2.2 Role of this deliverable relative to others in the project

This deliverable corresponds to Tasks 1.3.1, 1.3.2, and 1.3.3 in the project scope of work. It draws from the high-level feasibility analysis in Task 1.2.3 and the top four ranked ownership models in Task 1.2.5. Tasks 1.3.1, 1.3.2, and 1.3.3 specifically require an analysis of 1) the steps, timeline and costs of establishing each ownership model; 2) the legal changes necessary to implement each ownership model; and 3) the financial, business, macroeconomic, operational, and governance risks of each ownership model.

Several of the issues discussed in this deliverable will be subject to further analysis in subsequent Tasks. With regards to the costs of the ownership models, related tasks include:

- **Task 1.4.2. Economic evaluation of ownership and operation of each ownership model.** The Project Team will provide an economic evaluation of ownership and operation, including potential acquisition costs, severance costs, operating and maintenance costs, likely annual capital investments and costs, power supply sources and costs, startup and other nonrecurring costs, among many others.

- **Task 1.6.2. Analysis of how each ownership model would affect cash flows.** The Project Team will provide an analysis describing the cash flows of each model, including an overview of the accounting differences between ownership models (accrual vs cash basis) and the treatment of: 1) operations and maintenance expense; 2) taxes; 3) financing capital improvements; 4) depreciation; and 5) return on invested capital.

- **Task 1.6.3. Estimated revenue requirements under each ownership model through 2045; graphic comparing results.** The Project Team will provide the expected annual revenue requirement under each ownership model through 2045, including the identification of all major cost elements.

With regards to the steps of the ownership models, related tasks include:

- **Task 1.3.4. Assessment of how each ownership model impacts staffing of State agencies and stakeholders.** The Project Team will provide an estimate of the potential impacts a change in ownership model may have on the expertise and staffing requirements of related State agencies and stakeholders.

[14] Hawaii Contract No. 65595. Scope of Services.

- **Task 1.4.3. Assessment of management structure and staffing plan needs under each ownership model, including an assessment on the oversight management and staffing needs for PUC and Consumer Advocate.**[15] The Project Team will develop a management structure and staffing plan for each ownership model and include an estimate of the number of local jobs and associated salaries under each model.

2.3 Structure of this report

This report, which responds to Tasks **1.3.1, 1.3.2, and 1.3.3**, discusses four primary aspects of transitions in utility ownership. The first is a listing of the **practical steps necessary** to transition from the current ownership structure to a new structure, including an estimated timeline for the sequence and duration of these steps. The second are the **costs of such a transition**, including both acquisition and non-acquisition costs incurred in the transition. The third are the **legal changes necessary** to enable a change towards the ownership model. The fourth is an accounting and comparison of the **risks inherent in each ownership model**.

As discussed in the Task 1.2.5 report, this report assesses the formation and risks of four models of utility ownership:

- The **status quo** model (that is, an IOU in Honolulu, Hawaii, and Maui counties, and a co-op in Kauai county);
- A **Cooperative model** on each of the islands;
- A **single-buyer model** in which the single buyer (the entity responsible for overseeing the addition of all new generation capacity through its procurement and planning processes) is **external to the utility**; and
- A **single-buyer model** in which the single buyer is **within the current utility.**

In analyzing potential transitions in utility ownership, the Project Team made a series of assumptions about the specific transition that would occur in the different cases, which impacts the analytical approach taken in this report:

- **Status Quo**. Under the status quo model, there is no transition in utility ownership. Therefore, the discussions of steps, acquisition costs, and legal changes are not relevant for this model and are not included. However, the status quo is included in the risk assessment, so that the risks of alternative models may be compared to that of the status quo. Since the Cooperative model is already separately considered in the risk assessment,

[15] The "Consumer Advocate" refers to the Division of Consumer Advocacy, Department of Commerce and Consumer Affairs of the Hawaii State Government.

the status quo is represented in the risk assessment by the Investor Owned Utility (IOU) model.

- **Cooperative Model**. For the Cooperative model, the Project Team considers the steps, acquisition costs, necessary legal changes, and risks. Since Kauai Island Utility Cooperative (KIUC) is already a Cooperative utility and would not transition if this model were adopted, the Project Team only considers the HECO Companies as the acquisition target in its calculation of acquisition costs.

- **Single Buyer ("Inside" and "Outside" of the Utility).** The Project Team consider two variants of the single buyer model – one where the single buyer is a new entity that is outside of the utility (referred to as the "outside" single buyer), and one where the single buyer is formed within the incumbent utility (referred to as the "inside" single buyer). For both single buyer models, the Project Team considers the steps, costs, legal changes, and risks. However, since the single buyer model does not entail the purchase of any incumbent utility, the Project Team only considers up-front capital expenses and initial operating costs.

Based on this analytical framework, the rest of this report is structured as follows:

- **A brief discussion of the status quo ownership model**. This encompasses a description of the status quo ownership model and an overview of cost factors affecting the ability of the status quo model to achieve the State 100% renewable energy target.

- **Steps, costs and legal changes necessary for a transition to a Cooperative model**. For Costs, the Project Team estimates acquisition and transition costs. For legal changes, the Project Team evaluates legal considerations for the establishment, funding, and regulatory approval of the transfer of assets.

- **Steps, costs and legal changes necessary for a transition to a single buyer model.** Since many aspects of the steps, costs, risks, and legal changes of the "outside" and "inside" utility Single Buyer variants are similar or the same, we discuss these two model variants as part of a single chapter, but we note the areas where the implications of these models diverge. The analysis estimates the initial up-front capital costs and first-year operating costs of the Ontario single buyer. It also covers legal issues pertaining to the establishment, funding, and regulatory approval of the single buyer.

- **Assessment and comparison of risks inherent in the IOU, Cooperative, and Single Buyer ("outside" and "inside") models.** The Project Team evaluated the risks of each model in a separate section to best facilitate comparison across ownership models within certain risk categories.

3 Status Quo Model

The following section will describe the status quo ownership model and relevant cost factors for achieving Hawaii's 2045 100% renewable energy target through the status quo ownership model. The status quo ownership model, by definition, does not entail any steps, costs, or legal changes for creation, and thus the Project Team will not discuss those here.

The status quo utility ownership model in Hawaii is defined by an IOU (Hawaiian Electric Industries) that operates in Oahu, Hawaii, and Maui counties and a co-op (Kauai Island Utility Cooperative) that operates in Kauai county. In terms of regulation, the IOU is subject to "traditional" regulation in which it owns both generation and wires assets and the Public Utilities Commission (PUC) approves electricity rates to recover cost of providing service through those assets. The co-op, in contrast with how cooperatives are most frequently regulated on the mainland, is also subject to rate regulation by the PUC. However, the co-op is exempt from PUC regulation in other respects.[16] For example, unlike the HECO Companies, KIUC is exempt from the Competitive Bidding Framework, and is also not required to provide power supply improvement plans to the PUC for approval. These and other KIUC exemptions from PUC regulation will be described in the legal section of the co-op chapter.

However, the Project Team notes that the preservation of the status quo in terms of ownership models does not necessarily entail the preservation of the status quo in terms of regulation; it is possible for the State of Hawaii to implement regulatory approaches to ensure that the utilities achieve the State energy goals, while preserving the status quo ownership model. The Project Team will analyze potential avenues of regulatory reform in the second task of project work.

Many cost factors weigh on the ability of the status quo ownership model to achieve the 100% renewable energy target by 2045. The December 2016 PSIP from the HECO Companies outlined some of the key cost factors that influence the overall achievement of its target. These factors include:

- Lowered costs in both grid scale and residential distributed energy resources (DERs) and consequently, strong growth in its projected market share of generation assets;
- The cost of grid modernization needed to facilitate the uptake of DERs;
- Preservation of the flexibility to adapt to breakthrough technologies or fluctuating prices leads to uncertainty in long-term cost projections;
- The possibility of additional infrastructure upgrades, such as an inter-island transmission line would lead to greater up-front infrastructure costs but lower generation costs over the long term;

[16] HRS 269 § 31(b). More discussion of this KIUC exemption under this statute is provided in Section 4.5.4 below.

- Electrification of transportation potentially lowering electricity costs by encouraging greater renewable integration and load-shifting; and

- The desires and needs of various stakeholders, particularly the prospect of increased competition in distribution and retail electricity from initiatives (i.e. efforts from entities such as Paniolo Power) and requests with regards to resources (i.e. community opposition to the siting of wind power or the use of geothermal resources).

Most of these resource factors are not unique to the status quo and would be applicable to the other ownership models; for example, increasing use of DERs is likely to affect co-ops as much as it will affect the incumbent IOU. Grid modernization will likely be necessary over the long term in all models to facilitate the growth of such DERs. In the case of the single buyer, the resource requirements are likely to be comparable to the status quo ownership model, but the planning and procurement of such resources may differ. The following sections will outline in further detail the impacts that these proposed changes in the ownership model may have on the costs of achieving the 100% renewable energy vision.

4 Cooperative ("Co-op") Ownership

Prospective co-ops on each of Hawaii's islands can draw lessons from KIUC's acquisition of Kauai Electric from Citizen's Communications in 2002. While the acquisition process for KIUC spanned approximately three years,[17] the duration of a future co-op acquisition could be shorter, due to general knowledge of the process of KIUC's establishment and increased familiarity among the local population and energy stakeholders with the co-op model. For the formation of Cooperatives more broadly, the U.S. Department of Agriculture (USDA) notes that the process can take up to two years.[18]

In some respects, the creation of the co-op is similar to the formation of a nonprofit, and the potential acquisition of Hawaii Electric Company, Inc. (HECO), Maui Electric Company, Ltd. (MECO), and Hawaii Electric Light Company, Inc. (HELCO) (hereinafter referred to collectively as the "HECO Companies") assets is not unlike other utility mergers and acquisitions. However, the unique customer-owner membership structure of the co-op distinguishes it from other nonprofit entities. This model requires deeper customer engagement than the other ownership models and additional effort by co-op leadership in certain initiatives (i.e. membership outreach, recruitment, and engagement) to ensure success in formation and operation.

The following sections will outline the acquisition costs of the co-op purchase of the HECO Companies and the steps involved in establishing the co-op, including their estimated cost and timeline. It will then describe the legal requirements and feasibility of prospective co-ops in Hawaii.

4.1 Acquisition Costs

In the scenario in which a co-op or multiple co-ops acquire the HECO Companies, the acquisition cost will include the value of the assets, transaction costs, and transition costs. This report determines the value of assets through two methodologies: trading comparables (otherwise referred to as "trading comps") and comparable transactions. Transaction and transition costs are determined through empirical analysis of prior comparable merger and acquisition activity. These two methodologies provide a range of estimates for the total acquisition cost of the HECO Companies. Note that an additional third method of valuation – the discounted cash flow approach – will also be provided in Task 1.6.2 and 1.6.3.

To evaluate acquisition costs, this report considers the scenario of one co-op, or multiple co-ops, purchasing the HECO Companies in each county, which are roughly approximated through the

[17] KIUC was officially formed in November 1999 to purchase Kauai Electric by Citizens Communications. In 2000, the PUC proceeded to deny the acquisition of Kauai Electric by KIUC, prompting a subsequent renegotiation and regulatory proceeding in 2002 that culminated in the approval of the acquisition. The final acquisition occurred on November 1, 2002. This suggests that a timeline for subsequent acquisitions by prospective co-ops could be shortened through sufficient preparation for regulatory proceedings.

[18] U.S. Department of Agriculture, "How to Start a Cooperative," presentation slides, no date cited, available at: https://www.rd.usda.gov/files/publications/How%20to%20Start%20a%20Co-op.pdf.

subdivisions of HECO, HELCO, and MECO. Since KIUC is already a co-op, this analysis does not consider a purchase of KIUC as a part of this envisioned scenario.

Box 1. Key Financial Terms and Definitions

This box outlines the key terms and definitions in the following financial analysis:

- **Earnings Before Interest, Taxes, Depreciation, and Amortization ("EBITDA"):** EBITDA is a measure of profitability. It indicates earnings prior to the impact of the tax environment, financing decisions (or capital structure, in terms of debt versus equity), and depreciation of assets. It is calculated as the operating profit, plus the amortization expense and the depreciation expense. It is also calculated as the net profit plus interest, taxes, depreciation, and amortization.

- **Earnings Per Share ("EPS"):** EPS indicates the amount of profit, or net income, allocated per share of common stock in a given period. The EPS in this report utilizes the weighted average of diluted shares for 2016, since the number and quantities of available shares can change over time due to company repurchasing, reissuing, and other actions. Diluted shares reflect the total number of shares if all options and convertible securities are exercised.

- **Enterprise Value ("EV"):** EV indicates the total value of a firm, or the total sum of all claims by both shareholders and debtholders. It is measured as market capitalization plus debt, preferred shares, and minority interest, minus total cash and cash equivalents. One common way of characterizing EV is the total value of purchasing the company in its entirety, based on share price and current debts. This is also the deal value of a merger or acquisition of the entirety of the target company.

- **Equity Value:** Equity value, or market capitalization, is the value of a company available to shareholders. This contrasts with EV, which also includes the value from debtholders. Relative to EV, Equity Value is EV plus total cash and cash equivalents, minus debt, preferred shares, and minority interest.

- **Net Income:** Net income is the difference between revenues and cost of business, *including* all depreciation, amortization, interest, and taxes. It is not equivalent to EBITDA. It indicates the final profit that is available to shareholders.

- **Price/Earnings ("P/E") Ratio:** The P/E ratio indicates the market price per share, as indicated by market trading, divided by the earnings per share ("EPS"). It indicates the price an investor must pay to earn one dollar of earnings from the company in a given time period.

- **Trailing and Forward:** The term "trailing" and "forward" indicate the period of time under consideration for a financial measure. This report uses these terms in the context of P/E ratios, but these terms can apply to other measures as well. The trailing measure

utilizes financial data from the previous 12 months. The forward measure can cover the next 12 months, or for a certain period of time, such as a calendar or fiscal year.

For trailing months, one common acronym is TTM, which stands for Trailing Twelve Months. It indicates a measure that covers the previous twelve months. For the purposes of this report, the TTM for evaluating the HECO Companies is defined as Calendar Year 2016 (CY2016).

This analysis also uses forward P/E ratios for the next two calendar years (CY2018-CY2019) because forward estimates have statistically provided better predictions of value.[19] Such ratios typically utilizes the average of projected earnings by industry analysts of the company under consideration. However, this analysis also includes 2016 P/E ratios due to their empirical validity.

Source: Investopedia, Dictionary, see terms for "market value of equity," "enterprise value," "earnings per share," "differences between forward p/e and trailing p/e" net income," "EBITDA," available at: https://www.investopedia.com/. Additional description describes the analysis of the Project Team.

4.1.1 Valuation Approaches

The following section describes three methods for valuing the assets of the HECO Companies. The first approach describes the discounted cash flow analysis, which will be provided in Tasks 1.6.2 and 1.6.3. The second approach compares the price and earnings data of comparable publicly traded utility companies to the price and earnings data of the HECO Companies. The third approach uses prior comparable mergers and acquisitions activity to determine the "fair" market value of the HECO Companies. The second and third approaches – *trading comparables* and *comparable transactions* - utilize a combination of various multiples from a sample of similar companies to value the HECO Companies. These three approaches are industry-standard approaches for valuing companies. A brief description and comparison of each of these methodologies follows:

- The **discounted cash flow ("DCF")** analysis considers the time value of cash flows through a discount rate, which reflects the opportunity cost to generate cash flows. These cash flows are "discounted" over time to the present day to generate a present value. The discounted cash flow analysis is an intrinsic valuation approach because it is based on the fundamental characteristics of the firm, or cash flow, in this instance. Fundamentals of the firm are defined as growth rates in earnings and cashflows, payout ratios, and risk.

- In contrast, the **trading comparables (trading comps) analysis** is not an intrinsic valuation approach because it relies on market valuations of similar publicly traded companies and hence does not rely entirely on fundamentals of the target company. This approach

[19] Liu, Jing and Nissim, Doron and Thomas, Jacob K., "Equity Valuation Using Multiples", August 2000. Available at SSRN: https://ssrn.com/abstract=241266 or http://dx.doi.org/10.2139/ssrn.241266.

evaluates key measures or ratios from similar publicly traded companies that provide a benchmark for valuing the assets of the target company.

- Finally, **comparable transactions analysis** is based upon prior merger and acquisitions activity similar to the company under consideration. Hence, it is also not an intrinsic valuation approach. These precedent transactions can encompass companies that are not publicly traded. Like the comparable market trading analysis, a comparable transactions analysis utilizes various measures or ratios to value the target company.

Comparable (whether trading comparables or comparable transactions) valuation approaches offer several benefits beyond a glance at the stock price of HEI. First, as individual assets may be overvalued or undervalued in the market, it is expected that similar asset classes should bear relatively similar valuations when considered as a group, and so the average valuations of assets similar to the HECO Companies (i.e. utilities in possession of generation, transmission, and distribution assets) will provide additional information on the expected valuation of the HECO Companies. Second, utilizing HEI stock prices alone would also conflate its utility assets and its non-utility assets (primarily American Savings Bank). Finally, the stock price of HEI does not adequately capture the full value of utility assets since it only captures the price of equity ownership, and not the full enterprise value ("EV").

However, there are several caveats to a valuation approach based on comparable companies. Since the comparable company approach is a "non-intrinsic" approach towards company valuation, it is subject to transient market conditions, or factors outside of the control or ownership of the company in question, such as market fluctuations over time. Moreover, it may be difficult to determine exactly what is a "comparable" company to the HECO Companies, given that some companies may possess characteristics (unregulated assets, differing regulatory environments, etc.) that affect their valuation. That said, analyses based on comparable companies are a widely accepted methodology for valuation, in part because of their use of publicly available data.[20]

Using these two methodologies, this analysis provides a range of possible acquisition prices to approximate a "fair" market value for assets of the HECO Companies. These numbers bear the most relevance for a potential acquisition of the HECO Companies in their totality; it is less relevant for the single-buyer models, since the incumbent utility will retain ownership over its assets, but will no longer have control over the energy procurement and potentially planning functions.[21]

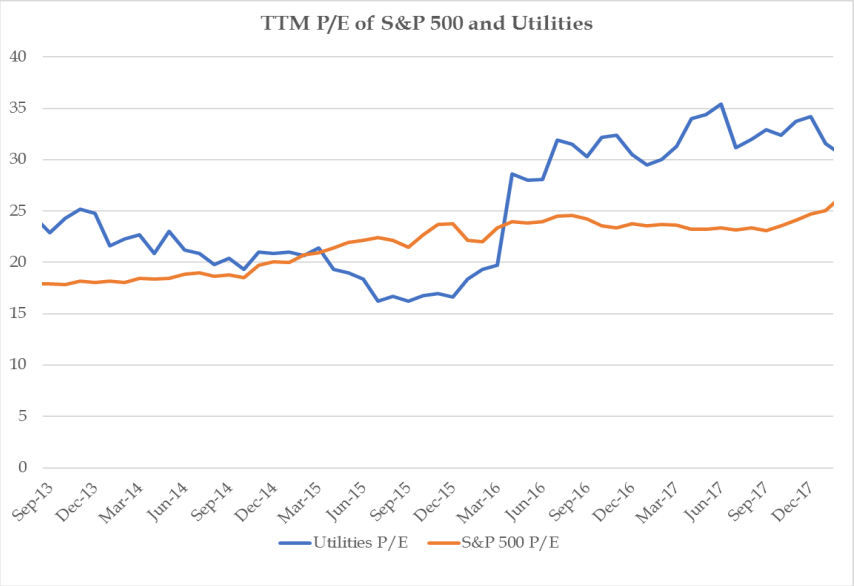
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[20] See the J.P. Morgan comparable company analysis of the proposed 2014 HEI-NextEra Merger in NextEra Energy, Inc., "Form S-4 Registration Statement," January 8, 2015, available at: https://www.sec.gov/Archives/edgar/data/753308/000119312515005172/d846219ds4.htm.

[21] As noted above, there are many potential variants of the Single-Buyer model. It is possible to implement a variant of this model in which the utility would retain planning responsibilities, though in this case their efforts must

For historical context, the proposed transaction value (which is equivalent to EV) of NextEra's proposal to acquire HEI was $4.3 billion dollars in 2014, which included the assumption of HEI debt and excluded the cost of purchasing American Savings Bank.[22] However, prior acquisition offers do not necessarily correlate with current value, since market conditions and the fundamental characteristics of the HECO Companies may have changed over the past three years. Moreover, consistent with the broader stock market, publicly traded utility companies have experienced a significant rise in forward prices relative to earnings (See Figure 2).[23]

Figure 2. TTM P/E of S&P 500 and Utilities Sector



Source: S&P500 P/E data is from multpl.com, accessed on February 11, 2018. Utilities P/E data is taken from GuruFocus Sector Valuation, accessed on February 11, 2018.

4.1.1.1 Trading Comparables Analysis

An analysis based on trading comps seeks to estimate the HECO Companies' enterprise and equity values based on various financial ratios from a peer group of utilities. For trading comps, the Project Team utilized 2016 data from the Energy Information Administration to narrow down a list of utility companies that are comparable to the HECO Companies. Utilities were selected

be closely coordinated with the Single Buyer's energy procurement responsibilities. In this analysis, we assume that the Single Buyer would assume planning responsibilities.

[22] NextEra Energy, "NextEra Energy and Hawaiian Electric Industries to Combine," December 3, 2014, available at: http://www.nexteraenergy.com/news/contents/2014/120314.shtml.

[23] See Figure 4 and Figure 24 of Yardeni Research, Inc., "Stock Market Briefing: S&P 500 Sectors & Industries, Forward P/Es," January 3, 2018, available at: https://www.yardeni.com/pub/mktbriefsppesecind.pdf.

based on: whether the utility is bundled or unbundled with generation assets (only bundled utilities were selected), whether the utility or parent is publicly listed (for data availability), whether the total amount of sales measured in MWh in 2016 is comparable to the HECO Companies (within a band of 75% to 125% of the HECO Companies' total sales in MWh), adjustments based on parent ownership characteristics (excluding any ownership that were multinational, not pure-play utilities, or were an order of magnitude larger in revenue than the HECO Companies), and whether the credit rating was comparable (only those within the medium investment grade bracket were included). Figure 3 outlines the process of narrowing the sample and the number of trading comparables.

Figure 3. Narrowing Down Trading Comparables

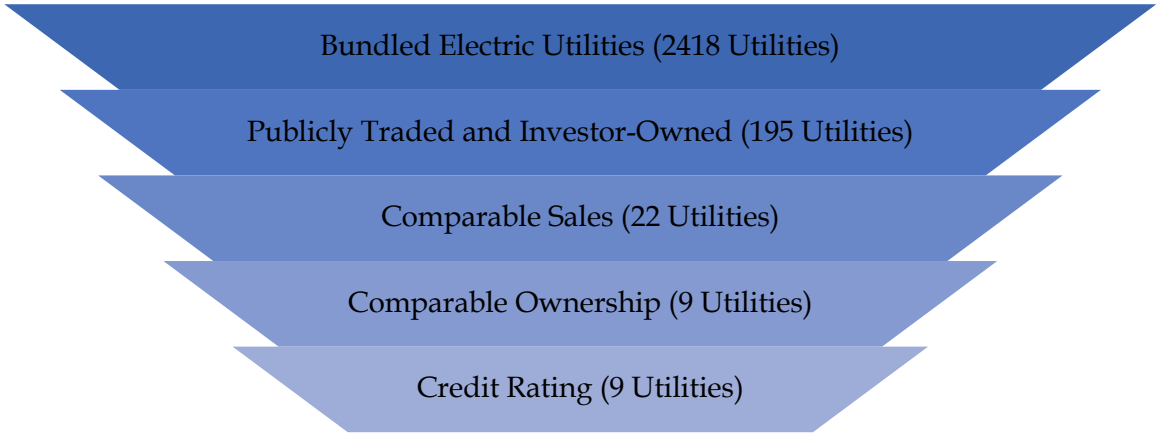


Figure 4 outlines the final selection of trading comparables, their generation capacity, 2016 Sales in MWh, location, and credit rating. Note that these companies were also included in the sample utilized for the J.P. Morgan trading comps analysis in 2014 to support the valuation of HEI at the time of the proposed NextEra merger. Figure 5 outlines the CY2016 EV/EBITDA ratios, P/E ratios for CY2016, and analyst average forward P/E for 2018 and 2019 of the trading comps. The forward estimates from J.P. Morgan's 2014 analysis for 2015 and 2016 are highlighted in yellow for comparison. The forward and historical P/E ratios and the EV/EBITDA ratio will be used to value the HECO Companies.

These ratios, applied in the context of the HECO Companies, provide a balanced indicator of firm value. EV/EBITDA provides a measure of earnings independent of capital structure for the entirety of the firm's value, including both debt and equity. EV, by definition, includes both debt and equity value. EBITDA, also by definition, is an account of earnings before interest, and hence is independent of the effects of capital structure on earnings. In doing so, this ratio provides a level basis of comparison for valuing utilities that may otherwise differ in capital structure. In

contrast, P/E ratios provide a basis of comparison for the relative cost to acquire an equivalent amount of earnings from the company after all intervening factors, including capital structure, are considered.

Figure 4. Characteristics of Comparable Publicly-Listed Utilities

Utility Name	Generation Capacity (MW)	2016 Sales (MWH)	Location	Credit Rating
ALLETE, Inc.	1,932	9,002,262	WI, MN	A3
Alliant Energy Corp. (Wisconsin Power and Light)	2,481	10,874,507	WI	A2
Avista Corp.	1,862	8,509,330	MT, ID, WA	Baa1
EL Paso Electric Co.	2,080	7,812,491	NM, TX	Baa1
Great Plains Energy, Inc. (Greater Missouri Operations Co.)	2,074	8,028,772	MO	Baa1
Northwestern Corp.	1,249	7,442,278	WY, SD, MT	A3
PNM Resources (Public Service Co. of NM)	2,481	8,951,524	NM	Baa3
Westar Energy Inc.	2,481	9,810,701	KS	Baa1
Wisconsin Energy Corp. (Wisconsin Public Service)	2,481	10,859,844	WI	A3
Hawaiian Electric Industries	1,669	8,845,335	HI	Baa2

Source: Credit Rating from Moody's. Sales and Location Data from EIA-861 Utility Surveys. Generation Capacity from 10-K forms or annual reports for all utilities and does not include IPP generation capacity.

Note that the forward 2018 and 2019 P/E ratios are approximately 20% higher than the forward 2015 and 2016 P/E ratios in the J.P. Morgan analysis (see the columns highlighted in yellow). The widespread increase in P/E ratios likely reflects a broader market-wide increase in stock prices relative to earnings over the past three years. With all other factors held constant, this higher P/E ratio indicates a basis for a potentially higher valuation of the HECO Companies relative to the valuation conducted in advance of the HEI-NextEra Proposal in 2014. A further analysis based on the 2016 and forward 2018 and 2019 P/E ratios (based on the average of industry analysts' estimates) following in the next two sections.

Figure 5. Forward P/E and EV/EBITDA of Comparable Publicly-Listed Utilities

Utility Name	P/E (2018E)	P/E (2019E)	P/E (2015E)	P/E (2016E)	P/E (CY2016)	EV/EBITDA (CY2016)
ALLETE, Inc.	20.6	19.1	16.2	14.9	23.1	10.6
Alliant Energy Corp.	19.6	18.6	17.5	16.6	24.3	12.7
Avista Corp.	25.1	23.3	17.3	16.9	24.0	9.5
El Paso Electric Co.	20.9	19.5	17.6	14.2	21.5	9.3
Great Plains Energy Inc.	18.0	16.4	15.1	13.8	19.1	9.0
NorthWestern Corporation	16.9	17.0	16.5	15.3	16.5	11.9
PNM Resources	22.9	19.3	18.6	16.0	25.0	9.7
Westar Energy Inc.	19.8	17.8	15.9	15.5	20.8	11.2
Wisconsin Energy Corporation	19.3	18.2	18.3	17.4	21.9	10.7
Median	19.8	18.6	17.3	15.5	21.9	10.6
Mean	20.4	18.8	17.0	15.6	21.8	10.5

Note: Data highlighted in yellow reflects Forward P/E ratios from J.P. Morgan analysis in 2014. Years followed by "E" indicate that this was an estimate of forward earnings. Hence P/E (2015E) was J.P. Morgan's forward estimate of the P/E ratio at the time of its 2014 analysis. The prefix "CY" before a year indicates that the metric is based on a calendar rather than a fiscal year.

Source: Forward P/E (2018E) and Forward P/E (2019E) data is from Thomson and Reuters I/B/E/S. Forward P/E (2016E) and Forward P/E (2015E) data is from the S-4 registration statement of NextEra Energy Inc. P/E (2016), and EV/EBITDA (2016) data is from YCharts as of January 11, 2018.

4.1.1.1.1 2016 P/E Comparison

In 2016, the net income attributable to common shareholders from the HECO Companies was approximately $142 million.[24] Similar to the J.P. Morgan analysis, this analysis deducts $20.5 million from net income; this reflects HEI corporate level-expenses that do not generate revenue and are not captured in financials of the HECO Companies and hence should not be included as part of the value of the utilities. This number is sourced from the average of similar corporate level deductions in the J.P. Morgan valuation analysis.[25] The deduction entails a cumulative net income of $122 million in 2016 for the HECO Companies, which divided by 108,865,000 weighted average diluted shares, yields a 2016 EPS for the HECO Companies of $1.12. For each of the specific utilities, after including the overhead deduction according to their relative contribution

[24] HEI, 2016 10-K Form, "Annual Report Pursuant to Section 13 or 15 (d) of the Securities Exchange Act of 1934," available at: http://www.hei.com/Cache/1500096268.PDF?O=PDF&T=&Y=&D=&FID=1500096268&iid=1031123

[25] Form S-4 Registration Statement, NextEra Energy, January 8, 2015, available at: https://www.sec.gov/Archives/edgar/data/753308/000119312515005172/d846219ds4.htm. The Project Team averaged the estimates of corporate level deductions and adjusted for inflation.

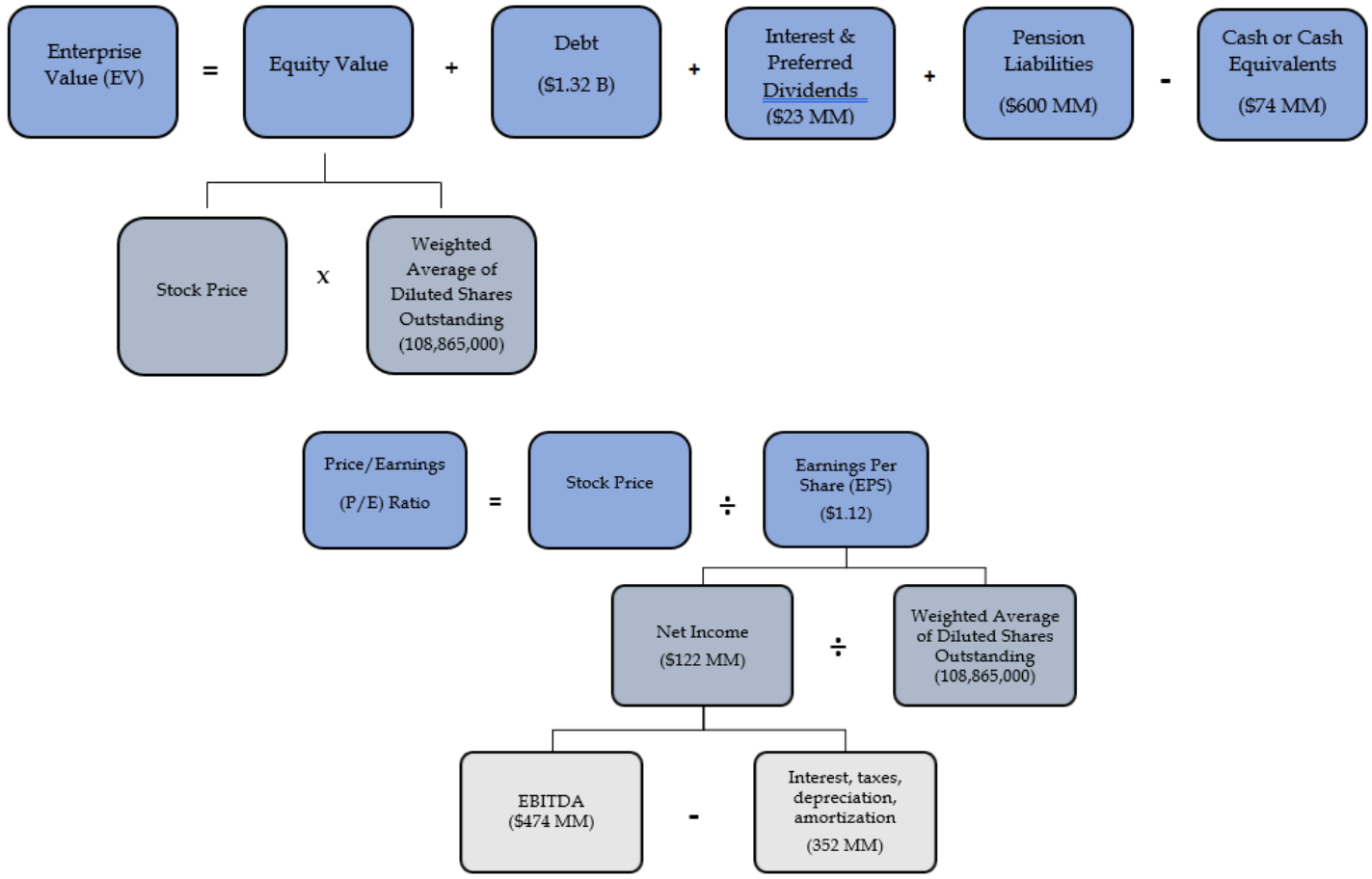
to net income, HECO yielded an EPS of $0.79, and HELCO and MECO both yielded an EPS of $0.17.[26]

Applying the median 2016 P/E ratios from the trading comps to these EPS values yields $24.44 per share for the HECO Companies. This is approximately equivalent to the price offered by the NextEra for the HECO assets at $25 per share.[27] To calculate the equity value of the company, our analysis multiplies the value per share by the outstanding number of diluted shares. To then calculate the EV of the company, our analysis adds the CY2016 long-term debt of the company ($1.32 billion), pension liabilities ($600 million), interest and preferred dividends ($23 million), and subtracts cash and cash equivalents ($74 million). Thus, the median 2016 P/E of the trading comparables yields an EV of approximately $4.5 billion, and an equity value of roughly $2.7 billion. In comparison, the EV of the NextEra Proposal was $4.3 billion.

[26] All 2016 figures for HEI were calculated based on the reported net income of the 2016 10-K form submitted by HEI for the fiscal year ending on December 31, 2016, "Annual Report Pursuant to Section 13 or 15 (d) of the Securities Exchange Act of 1934," available at: http://www.hei.com/Cache/1500096268.PDF?O=PDF&T=&Y=&D=&FID=1500096268&iid=1031123

[27] Although NextEra's final price was $33.50 per share, that included an $8 per share payment for ASB, and a $.50 payout per share to HEI shareholders. See "NextEra Energy and Hawaiian Electric Industries to Combine," NextEra Energy, Press Release, December 3, 2014, available at: http://www.nexteraenergy.com/news/contents/2014/120314.shtml.

Figure 6. Calculating the EPS, Equity Value, and Enterprise Value



Note: All figures encompass CY2016 and are from the 2017 10-K Reporting of HEI. EBITDA, Net Income, and hence the Earnings Per Share figures are adjusted for corporate overhead that is not included in utility financial projections.

The EPS figures also yields relative valuations for each of the individual HECO Companies. The median 2016 P/E of the trading comparables yields an approximate EV of $3.2 billion for HECO, $680 million for HELCO, and $666 million for MECO. The final summation of this valuation, including on a per share basis, is illustrated in Figure 7 below.

Figure 7. 2016 P/E Valuation of HECO, HELCO, and MECO (Trading Comparables)

Company	Trailing P/E Ratio	Enterprise Value	Equity Value	Per Share Valuation
HECO	Median	$3,182 MM	$1,868 MM	$17.16
	Mean	$3,179 MM	$1,865 MM	$17.13
HELCO	Median	$680 MM	$397 MM	$3.65
	Mean	$679 MM	$397 MM	$3.64
MECO	Median	$666 MM	$395 MM	$3.63
	Mean	$666 MM	$394 MM	$3.62
HECO Companies	**Median**	**$4,528 MM**	**$2,661 MM**	**$24.44**
	Mean	**$4,523 MM**	**$2,656 MM**	**$24.40**

4.1.1.1.2 Forward 2018 and 2019 P/E Valuations

This analysis now determines the forward P/E valuation of the HECO Companies. The first task is to determine the projected share of future earnings from the HECO Companies versus American Savings Bank (ASB). To determine the projected EPS for HECO, HELCO, and MECO, this paper averaged their relative contribution to the net income of HEI over the past five years (see Figure 8). The HECO Companies over the past five years constitute about 69% of net income for HEI each year. In terms of the individual HECO Companies, about 48% of net income is from HECO, with the remaining 21% contribution divided between HELCO and MECO. The band of the total utility contribution fluctuates around 69% with an upper limit of 73% and a lower limit of 63%.[28]

The forward EPS estimate for CY2018 is $1.83/share for all HEI including ASB and other activities. For CY2019, this forward EPS estimate rises to $1.87/share.[29] Using the above ratio of 69%, this suggests a forward EPS estimate of $1.27 per share for 2018 and $1.30 per share for 2019 for the HECO Companies (excluding ASB and other HEI activities). Again, the forward P/E valuation deducts $20.5 million from net income attributable to shareholders for overhead and other corporate expenses. This yields an overhead-adjusted forward EPS of $1.08 per share for 2018 and $1.11 for 2019 for the HECO Companies (see Figure 9).

[28] All data taken from respective 10-K forms submitted by HEI from 2012-2016. Available on the SEC Edgar website.

[29] Nasdaq.com Yearly Earnings Forecasts for stock ticker "HE," Accessed on January 16, 2018.

Figure 8. Relative Contribution of HECO, HELCO, and MECO to HEI EPS

	2016	2015	2014	2013	2012	Average
HECO Companies	0.71	0.71	0.73	0.68	0.63	**0.69**
HECO	0.50	0.49	0.51	0.45	0.45	0.48
HELCO	0.11	0.11	0.10	0.11	0.10	0.11
MECO	0.11	0.11	0.12	0.12	0.08	0.11
American Savings Bank	0.29	0.29	0.27	0.32	0.37	**0.31**

Source: Calculated using data from 10-K forms submitted from CY2012 to CY2016.

Figure 9. Trailing EPS and Forward EPS Estimates for 2018 and 2019

	2016 EPS	Forward EPS (2018e)	Forward EPS (2019e)
HECO Companies	$1.12	$1.08	$1.11
HECO	$0.79	$0.75	$0.77
HELCO	$0.17	$0.16	$0.17
MECO	$0.17	$0.17	$0.17

The median forward 2018 P/E ratios from the sample of comparable companies yields an total EV of the HECO Companies of $4.2 billion. This EV is divided into $2.9 billion for HECO, $637 million for HELCO, and $629 million for MECO. Figure 10 illustrates the per share valuation, equity value, and EV for each of these companies according to the median 2018 P/E forward estimates from the trading comps. For the HECO Companies, this is the equivalent to $21.38 dollars per share.

Figure 10. Forward 2018 P/E Valuation (Trading Comparables)

Company	P/E Ratio (2018e)	Enterprise Value ($)	Equity Value ($)	Per Share Valuation
HECO	Median	$2,928 MM	$1,614 MM	$14.83
	Mean	$2,973 MM	$1,658 MM	$15.23
HELCO	Median	$637 MM	$355 MM	$3.26
	Mean	$647 MM	$365 MM	$3.35
MECO	Median	$629 MM	$358 MM	$3.29
	Mean	$639 MM	$368 MM	$3.38
HECO Companies	**Median**	**$4,195 MM**	**$2,327 MM**	**$21.38**
	Mean	**$4,258 MM**	**$2,391 MM**	**$21.96**

The median 2019 P/E from our trading comparables yields a total EV of HECO Companies of $4.1 billion. This EV is divided into $2.9 billion for HECO, $624 million for HELCO, and $615 million for MECO. Figure 11 illustrates the per share valuation, equity value, and EV for each of

these companies according to median 2019 P/E forward from the trading comps. For the HECO Companies, this is equivalent to $20.55 per share.

Figure 11. Forward 2019 P/E Valuation (Trading Comparables)

Company	P/E Ratio (2019e)	Enterprise Value	Equity Value	Per Share Valuation
HECO	Median	$2,866 MM	$1,551 MM	$14.25
	Mean	$2,887 MM	$1,573 MM	$14.45
HELCO	Median	$624 MM	$341 MM	$3.14
	Mean	$628 MM	$346 MM	$3.18
MECO	Median	$615 MM	$344 MM	$3.16
	Mean	$620 MM	$349 MM	$3.20
HECO Companies	**Median**	**$4,104 MM**	**$2,237 MM**	**$20.55**
	Mean	**$4,135 MM**	**$2,267 MM**	**$20.83**

These figures generally align with the range of per-share results of the J.P. Morgan analysis using forward estimates, although they were for different years of comparison. The analysis of J.P. Morgan yielded approximately $19.45 to $21.90 per share based on an estimated CY15 forward EPS and approximately $20.85 to $23.65 per share based on estimated CY16 forward EPS.

4.1.1.1.3 2016 EV/EBITDA Valuation

Finally, this analysis utilizes CY16 EV/EBITDA to value the HECO Companies. From CY2016, the total EBITDA for the HECO Companies was approximately $490 million.[30] For EBITDA, this analysis deducts $16.3 million for corporate-level expenses, resulting in an adjusted EBITDA of $474 million.[31] The median CY16 EV/EBITDA ratio of 10.6 from the trading comps yields an equivalent EV of $4.9 billion.[32] To determine equity value, our analysis subtracts long-term debt ($1.32 billion), pension liabilities ($600 million), interest and preferred dividends ($23 million) and adds cash and equivalents ($74 million) in CY16 to yield an equity value of approximately $3 billion.[33] With 108,865,000 weighted average diluted shares outstanding, the median CY2016 EV/EBITDA ratio yields a price of $27.78 dollars per share.

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[30] HEI, 2016 10-K Form, "Annual Report Pursuant to Section 13 or 15 (d) of the Securities Exchange Act of 1934," available at: http://www.hei.com/Cache/1500096268.PDF?O=PDF&T=&Y=&D=&FID=1500096268&iid=1031123

[31] Form S-4 Registration Statement, NextEra Energy, January 8, 2015, available at: https://www.sec.gov/Archives/edgar/data/753308/000119312515005172/d846219ds4.htm. The Project Team averaged the estimates of corporate level deductions and adjusted for inflation.

[32] This is the "benchmark" enterprise value that implies changes in equity value. The impact of debt and other holdings on financial statements remains the same.

[33] All figures from the HEI 10-K Form.

The mean-median EV/EBITDA values in the J.P. Morgan analysis ranged from 8.2 to 8.8. In contrast, our analysis yields a mean-median EV/EBITDA value of 10.1 to 10.5, or approximately a 20-25% increase. One possible explanation for this increase is a change in market conditions since 2014, leading to rising P/E values and an increase in the market capitalization of firms, hence an increase in the EV. Alternatively, this increase could be a result of higher volumes of debt held by utilities due to lower interest rates, or even a decrease in overall EBITDA.

This figure also yields a valuation for HECO, MECO, and HELCO. Using data from 2016 HEI 10-K reporting, this analysis calculates the corresponding EBITDA for each of the HECO Companies to determine a corresponding EV. The results are approximately $3.4 billion for HECO, $849 million for HELCO, and $692 million for MECO (See Figure 12).

Figure 12. EV/EBITDA Valuation for CY2016 (Trading Comparables)

Company	EBITDA	EV/EBITDA Ratio	Enterprise Value	Equity Value	Per Share Valuation
HECO	$335 MM	Median	$3,351 MM	$2,037 MM	$18.71
		Mean	$3,400 MM	$2,086 MM	$19.16
HELCO	$85 MM	Median	$849 MM	$567 MM	$5.21
		Mean	$862 MM	$580 MM	$5.32
MECO	$69 MM	Median	$692 MM	$421 MM	$3.87
		Mean	$702 MM	$431 MM	$3.96
HECO Companies	**$490 MM**	**Median**	**$4,892 MM**	**$3,024 MM**	**$27.78**
		Mean	**$4,963 MM**	**$3,096 MM**	**$28.44**

These figures also generally align with the range of per-share results of the J.P. Morgan analysis using forward estimates, though they correspond to different years of comparison. The analysis of J.P. Morgan yielded approximately $21.25 to $25.90 per share based on CY2015E EBITDA and approximately $24.90 to $30.30 per share based on CY2016E EBITDA.

4.1.1.1.4 Results of the Comparative Trading Approach

Our analysis averages these four valuations for an approximate valuation from trading comps. An average of the median valuations from the 2016 P/E, 2018 forward P/E, 2019 forward P/E, and 2016 EV/EBITDA multiples yields approximately $23.54 per share or a total purchase price for utility assets of $4.4 billion (See Figure 13). Adjusted for inflation, this is roughly 2% less than NextEra's proposed purchase price of the HECO companies in 2014.[34]

Based on the median ratios from the sample of trading comparables, the valuation of HECO Companies could range from $20.55 to $27.78 per share. This is a higher band than the J.P. Morgan analysis, which concluded $19.45 to $23.65 per share. This is unsurprising, given that the forward P/E ratios are higher than J.P. Morgan's forward P/E ratios by approximately 20%. The

[34] Except where specified elsewhere, values reported in the assessment are in nominal dollars.

EV/EBITDA ratio is also higher than J.P. Morgan's EV/EBITDA ratio by approximately 20-25%. The increase in both ratios suggests a higher valuation.

Figure 13. Results of Analysis of Trading Comparables

	Average Enterprise Value	Average Equity Value	Average Cost Per Share
HECO	$3,082 MM	$1,768 MM	$16.24
HELCO	$697 MM	$415 MM	$3.81
MECO	$651 MM	$380 MM	$3.49
HECO Companies	**$4,430 MM**	**$2,562 MM**	**$23.54**

Finally, it is worth noting that potential rises in the interest rate may decrease the equity price of utilities. This is because rising interest rates would make bonds more attractive to investors, drawing investment away from equities in the utility sector. Moreover, the cost of debt may increase, lowering returns to equity holders, and thus lowering the stock prices of utilities.[35]

4.1.1.2 Precedent Transactions (M&A) Analysis

The precedent transactions approach seeks to value the HECO Companies based on prior merger and acquisition activity involving peer utilities. Using available data from the mergers and acquisitions sample set utilized in Task 1.2.2, the Project Team compiled a sample group of comparable mergers and acquisitions of utility assets. In compiling this sample set, the Project Team sought to narrow down to mergers and acquisitions that 1) included only bundled utilities, 2) encompassed the entirety of the company, 3) were friendly acquisitions, 4) occurred in the last five years, and 6) had available data. The resulting sample of mergers and acquisitions, and their relevant multiples are illustrated in Figure 14. Transactions also included in the J.P. Morgan analysis are highlighted in yellow. Note that the date is the *effective* date of the merger (and not the announcement date), which explains why some mergers after 2014 were included in the J.P. Morgan analysis.

Figure 14. EV/TTM EBITDA and Equity Value/TTM Net Income for Comparable Transactions

[35] See "To what extent are utility stocks affected by changes in interest rates?," July 7, 2015, Investopedia, available at: https://www.investopedia.com/ask/answers/070715/what-extent-are-utility-stocks-affected-changes-interest-rates.asp.

Target Company	Acquiring Company	Effective Date	EV (Deal Value)	EV/TTM EBITDA	Equity Value/TTM Net Income
Empire District Electric Co	Liberty Utilities Co	1-Jan-17	$2.4 B	10.8	26.3
TECO Energy Inc	Emera Inc	1-Jul-16	$10.4 B	11.6	71.2
UIL Holdings Corp	Iberdrola USA Inc	16-Dec-15	$4.7 B	11.4	27.2
Cleco Corp	Investor Group	13-Apr-16	$4.7 B	10.3	21.1
Integrys Energy Group Inc	Wisconsin Energy Corp	29-Jun-15	$9.1 B	11.3	18.0
Pepco Holdings Inc	Exelon Corp	23-Mar-16	$12.2 B	7.7	23.3
UNS Energy Corp	Fortis Inc	15-Aug-14	$4.5 B	9.2	18.1
NV Energy Inc	MidAmerican Energy Holdings Co	19-Dec-13	$10.4 B	10.3	16.9
CH Energy Group Inc	Cascade Acquisition Sub Inc	27-Jun-13	$1.5 B	10.4	20.9
Median				**10.4**	**21.1**
Mean				**10.3**	**27.0**

Source: All Data from Thomson and Reuters. Deals highlighted in yellow were also included in the J.P. Morgan comparable transactions analysis.

4.1.1.2.1 EV/EBITDA Comparison

Valuing the HECO Companies according to EV/EBITDA of comparable transactions is similar to the methodology for deriving the EV/EBITDA from trading comps. Instead of using trading comps, the analysis compares the EV and EBITDA from the HECO Companies to previous merger and acquisition activity of peer utilities.

Again, the total EBITDA for HECO Companies was $490 million in CY2016, from which $16.3 million is deducted for corporate-level expenses, resulting in an adjusted EBITDA of $474 million. The median EV/EBITDA multiple of the comparable transactions yields an equivalent benchmark EV of $4.9 billion. Our analysis again subtracts long-term debt, pension liabilities, interest, and preferred dividends, while adding cash and cash equivalents to yield an equity value of approximately $3.1 billion. This is equivalent to approximately $28.17 dollars per share.

Our analysis also determines the EV and share price of the individual HECO Companies based on this metric. Using the median EV/TTM EBITDA ratio from the comparable transactions, our analysis yields a total EV of $3.4 billion for HECO, $857 million for HELCO, and $698 million for MECO (See Figure 15).

Figure 15. EV/TTM EBITDA Valuation (Comparable Transactions)

Company	EV/TTM EBITDA	Enterprise Value	Equity Value	Per Share Valuation
HECO	Median	$3,380 MM	$2,066 MM	$18.98
	Mean	$3,354 MM	$2,040 MM	$18.74
HELCO	Median	$857 MM	$575 MM	$5.28
	Mean	$850 MM	$568 MM	$5.22
MECO	Median	$698 MM	$427 MM	$3.92
	Mean	$698 MM	$427 MM	$3.92
HECO Companies	**Median**	**$4,934 MM**	**$3,067 MM**	**$28.17**
	Mean	**$4,896 MM**	**$3,029 MM**	**$27.82**

4.1.1.2.2 Equity Value/Net Income Comparison

The median Equity Value/TTM Net Income ratio of our comparable transactions also lends insight into the potential value of the HECO Companies. The Equity Value/TTM Net Income provides a ratio of the value of equity, which is equivalent to market capitalization or the total value of shares, relative to how much net income will be available to shareholders after all other obligations and debts are paid.

For the equity value to net income ratio, the net income for the HECO Companies in 2016 was $142 million.[36] As previously mentioned, this analysis adjusts this net income for corporate overhead expenses of $20.5 million, yielding an adjusted net income of $122 million. The median Equity Value/TTM Net Income ratio for the totality of our data set thus yields an equity value of $2.6 billion, and EV of $4.4 billion, and a price of $23.59 per share. For the individual HECO Companies. This yields an EV of $3.1 billion for HECO, $666 million for HELCO, and $653 million for MECO (See Figure 16).

Figure 16. Equity Value/TTM Net Income Valuation (Comparable Transactions)

Company	Equity Value/TTM Net Income	Enterprise Value	Equity Value	Per Share Valuation
HECO	Median	$3,117 MM	$1,803 MM	$16.56
	Mean	$3,623 MM	$2,308 MM	$21.20
HELCO	Median	$666 MM	$384 MM	$3.52
	Mean	$773 MM	$491 MM	$4.51
MECO	Median	$653 MM	$381 MM	$3.50
	Mean	$759 MM	$488 MM	$4.49
HECO Companies	**Median**	**$4,436 MM**	**$2,568 MM**	**$23.59**
	Mean	**$5,155 MM**	**$3,288 MM**	**$30.20**

4.1.1.2.3 Results of Comparative Transactions Approach

[36] HEI 2016 10-K form.

The final results of the comparative transactions analysis are shown in Figure 17. The average share price of the two median ratios analyzed above yields a share price of $25.88 for the comparative transactions analysis, or approximately $4.7 billion for all utility assets. Again, this is within the range of $21.60 to $29.45 per share from J.P Morgan's analysis. However, like the comparable trading analysis, the Equity Value/TTM Net Income and the EV/TTM EBITDA ratios are both higher than the J.P. Morgan analysis:

- J.P. Morgan's analysis utilized 9.9 for the median EV/TTM EBITDA, while this analysis utilized 10.4 for EV/TTM EBITDA, or 5% higher than J.P. Morgan's ratio.
- For EV/TTM EBITDA, J.P. Morgan's Analysis utilized 19.7 for the Equity Value/TTM Net Income, while this analysis utilized 21.1 for Equity Value/TTM Net Income, or 7% higher than J.P. Morgan's ratio.

An increase in both these ratios was likely a contributing factor to the higher share price relative to the overall determination of J.P. Morgan. Some of the possible explanations for this general increase have already been discussed. Explanations include the increase in market capitalization and the increase in equity value since 2014.

Figure 17. Results of Comparative Transactions Analysis

	Average EV	Average Equity Valuation	Average Cost per Share
HECO	$3,249 MM	$1,935 MM	$17.77
HELCO	$761 MM	$479 MM	$4.40
MECO	$675 MM	$404 MM	$3.71
HECO Companies	$4,685 MM	$2,817 MM	$25.88

4.1.2 Transaction Costs and Transition Costs

Other sub-categories of the acquisition cost include transaction costs and transition costs. Transaction costs are defined as the cost of bringing the merging entities into an agreement and obtaining approval for the merger. These costs could include legal, regulatory, and investment banking fees. In contrast, transition costs include the costs to execute the consolidation. These include employee relocation, early retirement, and separation payments.[37] Data for transition costs are difficult to determine since cost allocation can be opaquely described in public documents, potentially categorized as part of the acquisition or transition cost of the asset, or classified as other cost categories or budget line items. On the other hand, transaction costs are sometimes publicly included as part of the merger process because regulators may seek to exclude such costs from utility revenue requirements.

[37] Scott Hempling, "Mergers and Acquisitions: Competition and Cost-Benefit Analysis," February 2001, p. 12, available at: http://www.scotthemplinglaw.com/files/pdf/ppr_mergers_and_acquisitions0201.pdf.

This report determines estimated transaction costs by evaluating a handful of prior transaction costs as a relative percentage of the EV of the target firm. From these handful of instances, one can approximate the legal, regulatory, and investment banking fees for the transaction at hand. The following cases were chosen based on availability of transaction cost data in docket proceedings. The transaction cost data included in the analysis is as follows:

- In the case of KIUC's acquisition of Kauai Electric, the transaction costs were $2.5 million in 2002 dollars, which is approximately 1.2% of the $215 million deal value.[38]

- The $1.5 billion acquisition of CH Energy Group by Fortis Inc. in 2012 incurred a transaction cost of approximately $15 million, or 1% of the deal value.[39]

- The $4.1 billion Northeast Utilities/NSTAR merger incurred a transaction cost of approximately $67.9 million, or about 1.6% of the deal value.[40]

- In the case of Iberdrola's acquisition of Energy East, the total transaction cost was approximately $24 million, or 0.53% of the deal value.[41]

- Finally, for Great Plains Energy acquisition of Aquila, transaction costs were $65 million for a $1.7 billion transaction, or 3.82% of the total deal value.[42]

These transaction costs are summarized in Figure 18. The median of these costs is 1.16%, while the mean is 1.63%. Given the above data, it is reasonable to assume that ownership model changes that involve a purchase of utility assets should expect a transaction cost of 1-2% of the deal value. Of course, this can vary, depending on how complicated the transaction is, the friendliness of the

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[38] "Kauai Island Utility Co-op: Financial Planning Model, Description of Schedules," Application for Approval for approval of the sale of certain assets of Citizens Communications Company, Kauai Electric Division and related Matters, Docket 02-0060, March 15, 2002, Available on the Hawaii Public Docket.

[39] CH Energy Group & Central Hudson Gas and Electric Corp, Annual Financial Report for the period Ended December 31, 2013, p. 40.

[40] Hartford Courant, "Northeast Utilities to buy NSTAR For $4.1 Billion In Stock, Creating Giant Utility," October 18, 2010, available at: http://articles.courant.com/2010-10-18/business/hc-ap-northeast-utilities-nstar-1018-20101018_1_nstar-shareholders-nstar-and-nu-nstar-ceo,

For specific transaction costs, see Robert Keegan, "Northeast Utilities/NSTAR Merger, D.P.U. 10-170 – Compliance Filing Regarding Transaction Costs, July 10, 2012, available at: http://170.63.40.34/DPU/FileRoomAPI/api/Attachments/Get/?path=10-170%2f71112nstcmpf.pdf.

[41] "Iberdrola S.A. Acquisition of Energy East: Information Request" PSC Case No. 07-M-0906, August 31, 2007, p.1, available at: http://www.dps.ny.gov/07M0906PolPnlEx2Att1.pdf

[42] Post-Hearing Brief of Joint Applicants Great Pains energy Inc., Kansas City Power and Light Co. and Aquila Inc., Case No. EM-2007-0374, p. 15, available at: https://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=515460705

transaction, its legal and regulatory challenges, billing practices of retained entities, and other considerations.

Figure 18. Transaction Cost Percentage of Transaction Value

Target	Acquiror	Transaction Value	Transaction Cost	Percentage
Citizens Communications	Kauai Island Utilty Cooperative	$215 MM	$3 MM	1.16%
CH Energy Group	Fortis Inc.	$1,500 MM	$15 MM	1.00%
NSTAR	Northeast Utilities	$4,170 MM	$68 MM	1.63%
Energy East	Ibredola	$4,500 MM	$24 MM	0.53%
Aquila	Great Plains Energy	$1,700 MM	$65 MM	3.82%
Median				**1.16%**
Average				**1.63%**

Sources: See footnotes to the bullet points described above.

4.1.3 Conclusion on Total Acquisition Cost

Using the dollar per share valuations outlined in the preceding analysis, this analysis determines that the acquisition cost, excluding transaction costs, can range from $20.55 to $30.20 per share, or $4.1 billion to $5.1 billion for all the HECO Companies. In the case of the purchase of individual HECO Companies:

- The acquisition cost (excluding transaction costs) of HECO is estimated to range from $14.25 to $18.98 per share, or $2.9 billion to $3.4 billion in EV.
- The acquisition cost (excluding transaction costs) of HELCO is estimated to range from $3.14 to $5.28 per share, or $624 million to $857 million in EV.
- The acquisition cost (excluding transaction costs) of MECO is estimated to range from $3.16 to $5.28 per share, or $615 million to $698 million in EV.

If the transaction cost is 1.16% of the total EV (the median of the above transaction cost figures), the total acquisition cost minus any transition costs could range between $4.2 to $5 billion. A summary of the three approaches, their ranges of value per share and EV of are included in Figure 19.

Figure 19. Range of Acquisition Cost Findings for the HECO Companies

Methodology	Low EV	High EV	Low $/Share	High $/Share
HECO	$2,866 MM	$3,380 MM	$14.25	$18.98
HELCO	$624 MM	$857 MM	$3.14	$5.28
MECO	$615 MM	$698 MM	$3.16	$5.28
HECO Companies	$4,104 MM	$4,934 MM	$20.55	$28.17

There are several caveats to this analysis. First, the non-intrinsic methods of valuation are subject to temporary fluctuations in the market, and thus arguably become less applicable over time. Such market fluctuations might affect the cash flows of the utility, affecting the intrinsic factors of the HECO Companies. The DCF analysis is also predicated on assumptions regarding growth and capital expenditure that may be similarly uncertain or variable. In a negotiated acquisition, these assumptions will be subject to negotiation and debate.

Second, in the scenario in which a co-op decides to purchase only one utility, but the rest of the HECO Companies are left under the ownership of HEI, the incumbent may value characteristics of the collective grouping of utilities that are not captured in the previous analysis. These can include synergies between companies or capabilities that may not be clearly obvious from the utility's financial statement. The incumbent utility may then require compensation for the loss of these synergies.

These caveats noted, this analysis provides a preliminary estimation of the value of the HECO Companies based on the industry-accepted methodologies for valuation. These numbers are meant to provide some guidance on the costs that prospective co-ops should expect when seeking to purchase some or all the HECO Companies.

4.2 Steps necessary to establish the co-op model

The following section outlines the steps necessary to establish the co-op model. It describes the requirements for the success of each step and the role of each step in establishing the co-op. Figure 20 offers a summary of the numerous steps to establish a Cooperative. Some of these steps are likely to overlap during the creation of the co-op, and the sequential nature of the steps will vary based on the island and context. For example, Hawaii Island already possesses a registered co-op entity,[43] and islands may also differ in terms of knowledge of and interest in the co-op model.

Unlike the single buyer model, the creation of co-ops has a long history in the United States and corresponding literature base. There are several useful resources to guide the steps involved in the creation of co-ops. The National Rural Electric Cooperative Association (NRECA) has published a series of technical assistance guides on co-op formation, including the associated studies, evaluations, and projects that may be undertaken in the establishment the co-op and its

[43] Hawaii Island Energy Cooperative has already registered to operate as a co-op on Hawaii Island. However, it does not currently own any generation, transmission, or distribution assets, and is seeking to acquire such assets from the incumbent utility.

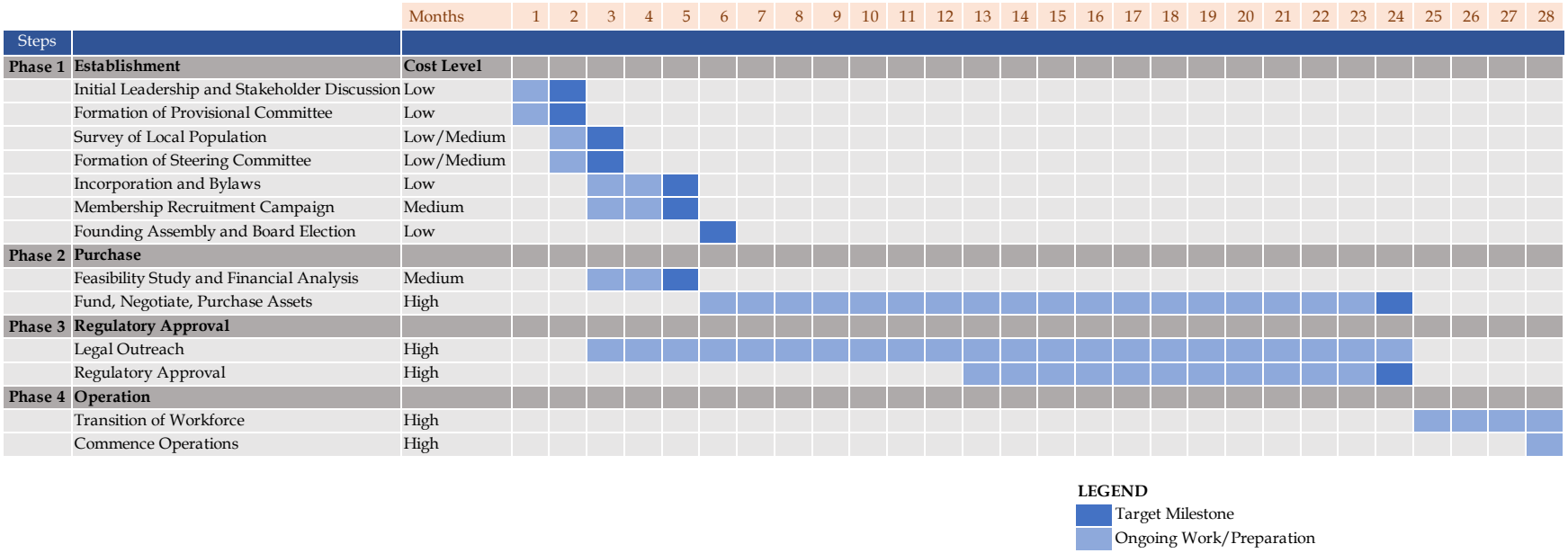
projects, although some of the insights may be more useful for international, rather than domestic audiences.[44] The second major source of resources is the USDA, which has published numerous reports on the various aspects of co-op ownership, albeit many of them are not specific to electric co-ops.[45] The following analysis draws heavily from these resources, recalls the history of co-op formation in Hawaii, including the docket proceedings of the 2002 KIUC acquisition and its preceding events, and confirms this analysis through interviews with policy experts and experienced practitioners, including individuals at KIUC.

Because of the wide variability in cost outcomes and the general unpredictability of potential factors that might affect formation costs, the following analysis classifies the cost of each step as either "low," "medium," or "high," with a *low* classification as reasonably falling under $10,000, *medium* as reasonably falling between $10,000 to $250,000, and *high* as any cost that is greater than $250,000. More specific estimates for these ranges are provided when supporting data is available. These cost estimates are made with the assumption that all the HECO Companies are being acquired, and are intended to represent the totality of the transactions. As Figure 20 illustrates, the costs generally tend to escalate further into the process of the co-op formation. The final steps of negotiating, funding, purchasing, and navigating the regulatory and workforce processes, are work-intensive and potentially very costly.

[44] For NRECA resources on establishing and running Cooperatives, see the numerous modules within the NRECA, "Guides for Electric Cooperative Development and Rural Electrification," No Date Cited, available at: http://www.nrecainternational.co-op/what-we-do/Cooperative-development/Cooperative-development-guide/.

[45] For an extensive repository of resources for establishing and running Cooperatives, see the "Publications for Cooperatives" section of the United States Department of Agriculture Rural Development, available at: https://www.rd.usda.gov/publications/publications-Cooperatives.

Figure 20. Example Steps and Timeline for Co-op Establishment



*Note: This Figure provides a hypothetical 28-month timeline for the creation of a co-op. It will be subject to the intervening factors outlined throughout this chapter.

4.2.1 Step 1: Initial Leadership and Stakeholder Discussion

Projected Cost: Low (<$10,000)
Projected Timeline: 1-2 months

The first step in the formation of a Cooperative is discussions amongst community leaders on the need for a Cooperative. This involves: 1) clearly defining the problem with the incumbent utility or electricity service, 2) describing the options (of which the co-op will be one option) for solving the problem, and 3) identifying whether and why a Cooperative is the preferable pathway for solving that problem. These preliminary discussions should include the stakeholders and community leaders that would eventually sustain and support the transition. In securing the stakeholders' participation, these dialogues help encourage stakeholder buy-in to the co-op model and gauge the landscape of interests for the creation of the co-op.

The costs of such initial leadership and stakeholder discussion are negligible and are hence classified as *low* cost. The timeline should at least plan for a month for invitations, events planning, and gathering feedback during the initial leadership discussion. This is only an approximate estimate; depending on the circumstances, the initial group of leaders involved in establishing the co-op model may want multiple sessions to resolve disagreements or compare potential solutions.

The scale at which this stakeholder discussion occurs in Hawaii could vary. Theoretically, a new Cooperative utility could form to serve the entire state, one or several islands, or a distinct service area on a single island.

4.2.2 Step 2: Formation of a Provisional Committee

Projected Cost: Low (<$10,000)
Projected Timeline: 1-2 months

If stakeholders identify the co-op as the preferred option, the next step in the formation of the co-op is for community leaders to form a Provisional Committee that would engage in initial project scoping. While the number of members of the Provisional Committee can vary, this Provisional Committee ideally would 1) possess requisite expertise in business formation (including business, legal, advocacy and engineering expertise) and 2) be selected or even elected from the initial participants to reflect and establish the consensus-driven governance mechanism of the co-op. Early use of these consensus-driven mechanisms for decision-making (i.e. through holding a vote) will help ensure that the formation of the co-op retains legitimacy throughout the various steps of its formation.

This Provisional Committee would be tasked with the essential work of defining the key characteristics of the co-op, gathering the information necessary for co-op approval, and

establishing initial management functions and procedures to delegate tasks among volunteers. Some of the key questions that the Provisional Committee should eventually seek to answer are:[46]

- What is the service territory of the proposed co-op?
- How can the co-op acquisition be financed?
- What capacities are necessary to own and operate the co-op? How can they be developed?
- What is necessary to achieve regulatory approval of the co-op acquisition?
- What are the desired objectives of the co-op (in terms of energy mix, costs, and rates, etc.)?
- What is the general community sentiment on establishing a co-op?

Are there any political challenges or hindrances to co-op formation and operation?

This is by no means a comprehensive list of questions and others are likely to emerge. At this stage, the Provisional Committee does not necessarily need thoroughly developed answers to these questions; more in-depth answers will emerge from subsequent feasibility analyses and the development of the business plan. However, the Provisional Committee ideally should be prepared to comment and provide a general vision regarding these key questions since they inform the viability of the Cooperative throughout the approval and subsequent operation.

At this point in time, the sole cost of the formation of Provisional Committee will likely be the time spent by the Committee to form the idea of the Cooperative, including any additional costs for setting up meetings. The Provisional Committee will also need to continue organizing exploratory meetings with Committee members and interested participants until the first annual meeting, or the founding assembly meeting. Absent donations or initial seed funding, these costs may come out of pocket for the initial leadership team and stakeholders, and potentially reimbursed later through membership fees. Regardless, these costs are likely to be *low* and are classified as such. While the formation of the Provisional Committee may vary from island to island, an estimate of one to two months of preparation is reasonable.

If helpful, the Provisional Committee should also seek an advisor to help guide them throughout the subsequent task of managing the creation of the co-op. Ideally, such an advisor would have experience in establishing co-ops in similar circumstances to the formation of a co-op in Hawaii (such as in the purchase of pre-existing assets, a diverse local population, etc.). Such an advisor would help prevent the co-op from making costly mistakes that could extend its timeline for formation.

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[46] For a more extensive guide, see NRECA, "Module 2: Guide for the Creation of Electric Cooperatives," available at: http://www.nrecainternational.co-op/wp-content/uploads/2016/11/Module2GuidefortheCreationofElectricCooperatives.pdf

4.2.3 Step 3: Survey the Local Population

Projected Cost: Low-Medium ($1,000-$40,000)
Projected Timeline: approx. 1-2 months

Following the formation of the Provisional Committee, one of the following major tasks is to survey the broader local population for views on a prospective co-op, what they might desire from a co-op, among other topics. Part of this survey will likely include education of the broader community on the prospective co-op. Important functions that this step serves are as follows:

- it gauges the acceptability of the co-op with the community;
- it informs community members of the prospect of co-op formation;
- it potentially assists with future membership recruitment and participation; and
- it helps align future business plans and financial analyses by discovering community preferences on potential changes in rates, capital contributions, etc.

Like most future steps, the Provisional Committee and prospective members should discuss the results of the survey and determine whether to continue with the formation of a co-op through a consensus vote. Generally, the Provisional Committee should seek a survey response that indicates that a greater percentage of the population supports the co-op than those who oppose. A significant portion of the population might also be undecided or uninformed on what a co-op is. If a significant portion of the local population opposes the idea of the co-op, then the formation of the co-op will potentially face regulatory challenges and potential threats to long-term sustainability.

The cost of such a survey will vary according to the sample size (i.e., the number of total responses), the means of communication, the length of the questionnaire, and the nature of the targeted population. For example, an internet-only survey could cost approximately $1.00 per response,[47] while a more direct phone survey could cost approximately $40 per response.[48] Depending on the desired sample size and degree of error, this could amount to a range from $1,000 to $40,000 if the survey desires a statistically rigorous and representative sample size. Given these numbers, this step could either be a *low* or *medium* cost, depending on the requirements and methodology involved. Such a survey would likely take at least one and a half months, including subsequent discussion and a vote on the survey results.

Finally, the Provisional Committee (and eventually the Steering Committee) should consider continuing surveys at key junctures of the co-op formation. While this should certainly include the initial ideation of the co-op, the Steering Committee (outlined in the following section) may

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[47] Quote from SurveyMonkey, a widely utilized online polling and survey platform. Accessed December 12, 2017.

[48] Entrepreneur.com, "Conducting Surveys and Focus Groups," available at: https://www.entrepreneur.com/article/55680#.

also want to consider additional surveys following subsequent marketing and recruitment campaigns as appropriate for the population of each service territory.

4.2.4 Step 4: Formation of a Steering Committee

Projected Cost: Low-Medium (<$100,000), subject to any compensation and contracting
Projected Timeline: approx. 2 months

Following confirmation of interest and support for a prospective co-op, NRECA and USDA both recommend the creation of a Steering Committee that will guide the Cooperative through its subsequent stages.[49] The Steering Committee should be more representative in its makeup and ambitious in its responsibilities than the Provisional Committee. In terms of its membership, the Steering Committee should represent all the major population areas, segments of society, and ethnic or racial groups that are present within the Cooperative service area. In terms of responsibilities, the Steering Committee is the key entity overseeing the technical, legal, and financial development of the co-op, and thus should possess expertise that might have otherwise not been present in the Provisional Committee. A short list of potential tasks is as follows:

- Incorporate and draft the bylaws of the co-op;
- Plan and delegate tasks involving the establishment of the co-op;
- Determine capital requirements and raise capital;
- Determine membership requirements and recruit members;
- Obtain all legal approvals for the transfer of assets;
- Educate the public about the co-op and its purpose;
- Plan and organize the Founding Assembly to vote on the bylaws and elect initial Board members.

As illustrated by these tasks, the Steering Committee is the main entity that manages the transition towards ownership and operation of utility assets. It serves as the point of communication between other stakeholders (the government, independent power producers, community organizations, etc.) and the local population invested in the creation of the co-op. It is also tasked with seeking technical assistance as appropriate.

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[49] See USDA, "Understanding Cooperatives, How to Start a Cooperative," April 2011 Revision, Available at: https://www.rd.usda.gov/files/CIR45-14.pdf

Also See NRECA "Executive Summary," Guides for Electric Cooperative Development and Rural Electrification, http://www.nrecainternational.co-op/wp-content/uploads/2016/11/Module2GuidefortheCreationofElectricCooperatives.pdf

The operating costs of the Steering Committee can vary. Absent significant initial seed capital, perhaps in the form of donations, initial membership dues, grants, or loans, members of a Steering Committee will mostly likely be volunteers. Thus, the costs related to the formation of the Steering Committee and performing its tasks are plausibly *low* to *medium* in magnitude. These Steering Committee members often go on to serve as board members of the co-op. Generally, co-ops should seek to allocate at least one month at a minimum for the formation and first gathering of the Steering Committee, particularly if they seek a representative group with the appropriate capabilities to guide the co-op through the previously mentioned tasks. At these initial Steering Committee meetings, members should strive to clearly outline the tasks at hand and the individuals responsible for those tasks.

At this stage, the Steering Committee should also consider reaching out to other Cooperatives and its broader network. This can involve institutions such as the National Rural Electric Cooperatives Association (NRECA) or other Cooperatives that own similar assets or have been recently established. NRECA was instrumental in the formation of KIUC by establishing training classes, bringing in leadership from other Co-ops, and gathering grassroots community support for the co-op.[50] For example, KIUC is a member of Touchstone Energy Cooperatives, which serves as a national network of electric Cooperatives that can provide resources and leverage partnerships. Such repositories of knowledge are one of the unique advantages of electricity co-ops.

4.2.5 Step 5: Legal Outreach

Projected Cost: High (>$250,000), subject to billing practices and legal contingencies
Projected Timeline: Ongoing

After its formation, the Steering Committee should retain legal counsel to assist them with the task of scoping out the various regulations that they will need to meet to 1) legally exist as an entity, and 2) legally acquire, own and operate the assets[51] of the HECO Companies, or any portions thereof: HECO, MECO, and HELCO. From the outset, the co-op should actively reach out and engage the PUC, the Consumer Advocate and other governmental entities on the various tasks necessary for the formation of the co-op. Some of these tasks will include:

- Drafting of the Articles of Incorporation and Bylaws;
- Necessary legal and regulatory requirements for the transfer of assets to the co-op;
- The determination of tariffs or other relevant rules;

[50] Dennis Hollier, "Who Should Own Hawaii Electric?" October 2015, Hawaii Business, available at: http://www.hiec.co-op/docs_and_pdfs/1510-who-should-own-hawaii-electric.pdf.

[51] See discussion in Section 4.2.9 below.

- Applicable employment regulations.

The legal costs of establishing the co-op are subject to a broad range of considerations that make an estimate of final costs difficult. Most law firms will charge by an hourly rate, although others may seek instead a percentage of the total acquisition value. Moreover, the legal challenges can vary considerably, leading to significant differences in total rates. There is also not a generally reliable source for the extent of the legal costs. Although a more thorough breakdown of costs is unavailable, in the case of KIUC, approximately $2.5 million in 2002 dollars was allocated for transaction costs, of which legal costs were a partial component.[52] This is approximately the equivalent of $3.5 million in 2017 dollars. For this analysis, the Project Team includes legal costs as part of the 1.5% transaction cost of the transaction value, suggesting that at this stage, the costs of legal advising would be *high* in magnitude.

4.2.6 Step 6: Feasibility Studies and Financial Analysis

Projected Cost: Medium-High (>$10,000), subject to competitive procurement and deliverable quality
Projected Timeline: 2-3 months

Following its establishment, the NRECA and USDA both recommend that the prospective co-op undergo a series of feasibility studies and planning to determine the financial sustainability of the co-op and prepare materials for regulatory and funding approval. If necessary, the Steering Committee should contract a consulting firm with expertise in the relevant areas to conduct these analyses. Ideally, the Steering Committee would procure these studies through a competitive procurement process. At a minimum, these studies should cover the following topics:[53]

- **Market analysis.** With a market analysis, the prospective co-op seeks to evaluate whether the existing market of energy producers and consumers is sufficient to justify the costs that would be involved in the co-op's acquisition and subsequent operation of utility assets. This analysis should include the total number of consumers, different consumer segments (in terms of residential, commercial, and industrial, among other characteristics), projected growth in these market segments, barriers to entry, the regulatory environment, broader trends in energy production and consumption, and any other relevant factors.

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[52] A specific breakdown of these transition costs was unavailable in the docket proceeding.

[53] The following list is drawn from NRECA, "Module 4: Business Plan for Electricity Cooperatives," available at: http://www.nrecainternational.co-op/wp-content/uploads/2016/11/Module4BusinessPlanforElectricCooperatives.pdf, "Module 5: Methodology for Evaluating Feasibility of Rural Electrification Projects," available at: http://www.nrecainternational.co-op/wp-content/uploads/2016/11/Module5MethodologyforEvaluatingFeasibilityofRuralElectrificationProjects.pdf and "Module 6: Willingness to Pay and Economic Benefit Analysis," available at: http://www.nrecainternational.co-op/wp-content/uploads/2016/11/Module6ConsumerWillingnesstoPayandEconomicBenefitAnalysisofRuralElectrificationProject.pdf

- **Willingness-to-pay analysis.** The co-op should also assess the willingness of the market participants to pay for various energy services. This information can be gathered through surveys or other research methods, but it should strive to yield an estimate of what consumers are a) currently paying for their energy services and 2) willing to pay assuming certain scenarios or actions that may occur because of the co-op transition or under co-op ownership. This will provide a sense of whether the transition will remain politically feasible and whether the transition towards the co-op can accomplish certain goals.

- **Engineering analysis.** The Steering Committee should commission an engineering analysis to verify the potential costs of owning and operating the new system and any other contingencies that may arise. For example, one potential scenario that would benefit from an engineering analysis involves separation costs if that the co-op is only acquiring a certain subsection of a broader electricity grid on an island. This would be especially significant in the case of the physical severance of the two systems, which may require duplication of facilities or infrastructure.[54] In this case, a thorough engineering analysis would be necessary to verify such separation costs.

- **Financial analysis.** With a more thorough understanding of the costs involved in the acquisition and operation of utility assets, the willingness-to-pay, and the market for energy services, the Steering Committee should then conduct a more thorough and comprehensive financial analysis that assesses how the co-op can be financially solvent. Ideally, the financial analysis should acknowledge the capital structure of the co-op and illustrate a plan to convert debt to equity over time based on realistic assumptions. Such a plan should also illustrate prudent management of financial risks. In addition to the business plan, this financial analysis will be necessary to illustrate due diligence and acquire funding from prospective lenders.

- **Business plan.** Finally, the Steering Committee must develop a business plan that comprehensively integrates the financial analysis, risk analysis, willingness-to-pay analysis, engineering analysis, and any other necessary factors or considerations. The formation of a business plan should encourage co-op members to rigorously address every aspect of the transition and operation of the co-op. Moreover, such a business plan is necessary to show to potential lenders that co-op members have undergone the due diligence necessary to operate the utility business. Ideally, plans will address at a minimum: management, operations, marketing, power supply and delivery, regulatory approvals, and the implementation timeline.

The timeline and costs of these steps can vary significantly, but they are likely to be at least *medium* in magnitude, assuming that co-op leadership desires deliverables that are rigorous and well-supported. For most electricity systems, it is not unreasonable to expect that these deliverables could take approximately up to three to six months total, from procurement of consulting services to final approval. Similarly, the costs of these analyses can vary according to their quality. Ideally,

[54] There is also the possibility of administrative segregation, which is generally less costly than physical separation. In this case, utilities share information and retail billings of one utility are provided by the other utility.

the Steering Committee will procure such proposals through a competitive request for proposals and will secure a contractor that possess the expertise to evaluate these issues.

Following each of these deliverables, the Steering Committee should undergo a series of evaluative steps. The first step is to thoroughly analyze the report or deliverables of each of these steps, examine assumptions, methodologies, and other critical data, and determine whether the deliverable is acceptable. If it is not acceptable, the Steering Committee should voice its concerns and seek an updated deliverable. If it is acceptable, then the Steering Committee should hold a public meeting with prospective members of the Cooperative to discuss the outcomes of the study. After subsequent discussion of each deliverable, the Steering Committee should hold a vote on next steps, particularly whether to proceed with the co-op formation or explore other solutions.

4.2.7 Step 7: Incorporation and Bylaws

Projected Cost: Low (<$10,000)
Projected Timeline: 2-3 months

If the market and membership potential is promising, and there are clear avenues for capitalization, the Steering Committee should proceed with incorporating the co-op entity. On the Big Island, the Hawaii Island Electricity Cooperative (HIEC) is already an established Cooperative that could undertake ownership of the utility. On other islands, community leaders would need to incorporate a Cooperative entity. Generally, the legal task of incorporating a co-op is straightforward; however, incorporation requires determining who shall be the officers, incorporators, etc., among other substantive determinations. This step constitutes the "legal" step of establishing the co-ops' legal entity under Hawaii law. Box 2 outlines the legal requirements of the Articles of Incorporation, which shall be filed with the State of Hawaii Department of Commerce and Consumer Affairs. The Articles of Incorporation typically closely model the language of the statutory requirements, given that its task is relatively simple.[55] In contrast, the Bylaws can be substantially more elaborate than the statutory language.[56]

Box 2. Legal Requirements: Articles of Incorporation

[55] *See* HRS § 421C-11.5.

[56] *See* HRS § 421C-12.

The following excerpts the relevant section from the legal requirements for the Articles of Incorporation of a Cooperative in Hawaii from Hawaii Statute. Note that KIUC was incorporated without stock:[57]

> *(a) Articles shall be certified and executed by each of the incorporators, if natural persons, and by the president and secretary of the association, before any officer authorized to take acknowledgments, and shall contain the following:*
>
> 1) *The name of the association which shall contain the term "Cooperative" or some abbreviation thereof notwithstanding section 421-5;*
> 2) *The mailing address and zip code of its principal office, which shall be in the State, the street address of the association's initial registered office, and the name of its initial registered agent at its initial registered office;*
> 3) *The purposes and powers of the association;*
> 4) *The duration of the association;*
> 5) *The number, names, and titles of the initial officers and directors, or similar officers;*
> 6) *The names and addresses of the incorporators, and if organized with stock, a statement of the number of shares subscribed by each, which shall not be less than one, and the class of shares for which each subscribed;*
> 7) *If organized with stock, the total authorized number of shares and the par value of each share, if any; and if more than one class of stock is authorized, a description of the classes of shares, the number of shares in each class, the relative rights, preferences, and restrictions granted to or imposed upon the shares of each class, and the interest-dividends to which each class shall be entitled; and*
> 8) *If organized without stock, whether the property rights and interest of each member are equal or unequal, and if unequal, the rule by which the rights and interest shall be determined.*
>
> *(b) The articles may also contain any other provisions, consistent with law for regulating the association's business or the conduct of its affairs. [L 1984, c 217, §4; am L 1988, c 373, §23; am L 2003, c 124, §46]*

Source: HRS § 421C-11.5 (2016).

The next task is to draft the bylaws of the co-op. This task will likely require more effort than incorporation; again, while the task of drafting bylaws is relatively straightforward, the underlying issues involving the bylaws require more deliberation. While the Box 3 below illustrates the statutory requirements for the bylaws, each of these requirements can require

[57] HRS § 421C-3 allows for a co-op to be organized with or without stock. Further, this statute provides that if the co-op is organized with stock, the co-op shall require a certain amount of common stock to be purchased from the co-op in order to permit stockholder voting and membership privileges (subject to HRS § 41C-20). No class of stock except common stock may grant voting and membership privileges. If the co-op is organized without stock, the co-op shall require a membership fee or amount of membership capital to be paid in, in order to permit the member voting and membership privileges by means of issuance of a membership certificate.

elaborating procedures or details substantially beyond the model language. KIUC, for example, is on the seventh revision of its bylaws, demonstrating how its utility management is continually adapting to new circumstances.[58] Some of the provisions contained in the KIUC bylaws cover the following:[59]

- *Membership requirements*, including eligibility, fees, conditions for inactivity, expulsion, termination, withdrawal, and the effects of these conditions on voting rights, holdings, electricity service, and other contracts.[60]

- *Provisions for the meetings of members,* such as the provision of annual and special meetings, the requisite timing for notices of such meetings, and the methods of advertising for such meetings.[61]

- *Procedures for voting*, including the number of votes allocated to each member, the rights of each member to vote on motions, resolutions or amendments, the procedures for voting, and requirements for vote counting (i.e., by independent third party). [62]

- *Quorum requirements*, which outline how many members or Board members are necessary to generate a vote at one of the meetings.[63]

- *Director requirements*, including the qualifications, number, nomination (whether through a committee or member petition), selection, compensation, and removal. This also includes the role, responsibilities, and authorities of the directors at annual, regular, and special meetings, and their authority to conduct other tasks, including developing additional committees, bonds, and assurance, agreements, accounting, etc. [64]

- *Officer requirement*s, including their election, removal, duties, compensation, and responsibilities.[65]

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[58] Kauai Island Utility Cooperative, "Seventh Revised and Restated By-Laws of Kauai Island Utility Cooperative, March 28, 2009, available at: http://website.kiuc.co-op/content/bylaws ("Seventh A&R Bylaws of KIUC").

[59] *Id.*

[60] *See* Article I of the Seventh A&R Bylaws of KIUC.

[61] Article II of the Seventh A&R Bylaws of KIUC.

[62] *Id.*

[63] *Id.*

[64] Article III of the Seventh A&R Bylaws of KIUC.

[65] Article V of the Seventh A&R Bylaws of KIUC.

- *Management of patronage capital,* including its distribution, allocation of losses, allocation of revolving capital, refunds, transfers, maximum percentages allowed, etc.[66]

- *Amendments to the bylaws*, including processes and vote requirements.[67]

Box 3. Legal Requirements. Bylaw Requirements on Co-ops in Hawaii

The following excerpt outlines the statutory requirements of the bylaws of the co-ops in Hawaii:

> *§421C-12 Bylaws; contents. The bylaws shall contain:*
> *(1) The maximum amount or percentage of capital which may be owned or controlled by one member;*
> *(2) A provision that in all decisions to amend the articles or bylaws, as the case may be, the members shall be informed of those decisions at least thirty days in advance through a mailing or a prominent notice at all association locations;*
> *(3) The method and terms of admission to membership and the disposal of members' interests on termination of membership for any reason;*
> *(4) A provision stating that a majority of the directors, or five per cent of the members or two hundred fifty members, whichever is less, may submit a petition in writing and demand a special membership meeting, which shall be called by the secretary within thirty days of that demand;*
> *(5) A provision that notice for all meetings shall be made through posting prominent signs at all association locations or by mailing to the last known address of each member or director. Notices for special meetings shall specify the purpose of the meeting;*
> *(6) A provision that associations shall not discriminate on their acceptance of members on a basis of race, gender, religion, income, marital status, or nationality; and*
> *(7) A provision stating that within a specified period of time, any action taken by the directors must be referred to the members for approval or disapproval if demanded by petition by at least five per cent of the members or two hundred fifty members, whichever is less, or by majority vote of the directors; provided that rights of third parties which have vested between the time of action by the directors and approval or disapproval by the members shall not be impaired. [L 1982, c 97, pt of §2; am L 1984, c 217, §5; am L 2001, c 129, §65]*

Source: HRS § 421C-12 (2016)

Although some of these categories track closely to the statutory requirements, they are also substantially more detailed, particularly in outlining the responsibilities officers and directors. Determining the substance of these bylaws is subject to deliberation within the co-op and may evolve over time. Therefore, it is also incumbent on co-op members to consider the process for deliberation and discussion on concerns regarding the bylaws.

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[66] Article VII of the Seventh A&R Bylaws of KIUC.

[67] Article X of the Seventh A&R Bylaws of KIUC.

In terms of timeline, the Articles of Incorporation is a straightforward task and can be completed relatively quickly. However, it is more difficult to generate an estimate of bylaw formation since it is subject to contextual factors, particularly with regards to the ability of stakeholders to agree on certain processes. The actual cost of filing these fees are low. For an electricity Cooperative without a capital stock, the cost of filing Articles of Incorporation with the Hawaii State Government is only $25 and an additional $25 for expedited review.[68] Therefore most of the cost of drafting the bylaws will likely result from the legal fees of retaining a lawyer to draft the text of the bylaws, as well as the actual time and money spent meeting to deliberate over the bylaws, which are likely to be *low* in magnitude due to the straightforward nature of the task.

4.2.8 Step 8: Membership Recruitment Campaign

Projected Cost: Medium (<$100,000)
Projected Timeline: 2-3 months

While this report describes membership recruitment as a step that follows the Articles of Incorporation and the Bylaws, membership recruitment should be an ongoing process throughout the establishment of the Cooperative. This is because membership in the co-op is an essential metric and determinant of success. The campaign to recruit members plays an indispensable role in ensuring the long-term sustainability and implementation feasibility of the Cooperative model.

To an extent, membership in the Cooperative is an indicator of political acceptance within the local community. If the Cooperative is not politically accepted amongst the local population, then it is more likely that the acquisition effort will be subject to a variety of stipulations and objections during the approval process with the PUC. If the co-op lacks political support among the local community, it will be subject to long-term challenges to its sustainability. Some examples include possible legislative action or a hostile takeover.

That noted, since there is no retail choice in Hawaii, membership might not have significant effects in terms of revenue gathered from energy services. Consumers within a certain territory would have to purchase energy from an operational Cooperative utility regardless of whether they are a member. Still, their membership confers many benefits, and the co-op should strive to communicate those benefits to the prospective members and encourage their active participation.

Several methods can assist with the recruitment of membership into the co-op; these range from surveys, focus groups, community workshops, door-to-door recruitment, marketing campaigns, among others. As a rule, the membership of co-op should strive to mirror the constituents of the service population in terms of diversity of the population. This helps to confer legitimacy to the co-op and ensures that it adequately represents the desires of all its customers.

The total cost of such membership recruitment campaign will vary by ambition, preexisting interest, the size of the co-op, and the fees that the co-op charges for membership. Moreover, the

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[68] Hawaii Department of Commerce and Consumer Affairs, "Fees/Hawaii Business Corporation Act, Chapter 414," No Date Cited, available at: http://cca.hawaii.gov/breg/registration/dpc/fees/

timeline of membership recruitment can begin from the early stages of co-op formation and continues past the first day of operation of the co-op. For timeline, this report outlines that membership should begin after the initial community leadership meetings, but should be more significant and engaged leading up to the founding assembly meeting. The cost could be defrayed by relying primarily on the time and efforts of volunteers and supporting networks such as NRECA. However, a more extensive marketing effort would be costlier, and these costs are likely to at least be *medium* in magnitude if the co-ops seek adequate participation from the 1.5 million population of Hawaii.

4.2.9 Step 9: Founding Assembly Meeting and Election of the Board

Projected Cost: Low (<$10,000)
Projected Timeline: 1 month

Following an extensive membership recruitment campaign, the Steering Committee should organize a Founding Assembly meeting for the two significant steps of 1) electing an initial board of governors and 2) approving the bylaws of the organizations. While the cost of holding this founding assembly meeting and an election is likely to be *low* in magnitude, the utmost care should be taken in organizing and holding this meeting. In addition to the steps above, the Founding Assembly meeting should gather feedback from community stakeholders. Given the significance of this meeting, co-op members should strive for broad inclusion in this meeting. Broader participation in this meeting will help ensure the legitimacy of the co-op and secure its political support.

The Steering Committee should prepare rules for debate over these key steps. The Steering Committee should also outline procedures for the vote on these two tasks and should document the content of the deliberation at this initial meeting.

After the Board of Directors is elected, it should meet as soon as possible to:

- Hold elections for the officer positions of the Cooperative;
- Delegate responsibilities to each member of the Board; and
- Craft an implementation plan for the Cooperative, which includes:
    - Identifying required capabilities and staffing;
    - Establishing brick and mortar facilities for the co-op;
    - Complying with all necessary accounting and business practices;
    - Hiring a manager(s) to undertake these responsibilities;
    - Obtaining advisory services as needed; and
    - Acquiring utility assets.

The next few sections will outline some of the steps involved in the acquisition process. While this report dedicates more attention to the funding and purchase of utility assets, co-ops should also prepare these additional in-house capacities to ensure that they can undertake utility responsibilities when the time comes and to justify the acquisition to the PUC.

The initial timeline of this step should be approximately one month for adequate advertisement of the initial founder's meeting. The subsequent tasks of the Board of Governors will likely evolve over time, but the initial, subsequent meetings, hiring of managers, and securing a brick and mortar facility should take approximately two months. The costs of these subsequent tasks will be variable and subject to the size and capabilities of the prospective co-op.

4.2.10 Step 10: Fund, Negotiate, and Purchase Assets

Projected cost: $4-5 billion, subject to negotiation and valuation (see prior section on acquisition costs)
Projected timeline: 14-25 months, including the regulatory approval process.

The next step is to fund, negotiate, and purchase the HECO Companies. This step requires extensive engagement with prospective lenders, such as the USDA's Rural Utilities Service, the National Rural Utilities Cooperative Finance Corporation, and the National Cooperative Services Corporation. While the capital structure of the prospective utility may vary, generally co-op entities will undertake debt to 1) cover the initial cost of the purchase of the utility; 2) provide working capital for all transitional expenses; and 3) cover the transaction costs. This report outlines estimates for these costs in greater detail in prior sections.

These loan programs have unique requirements and rates. Some of these requirements may require that the Cooperative in question meets the requirements of being "rural" as defined in the federal legislation. Additional rules may require that the co-op provides a significant amount of up-front capital, although this is not necessarily required for co-op funding; for example, KIUC was virtually entirely leveraged at its inception. Finally, the co-op must be able to produce a rigorous business plan and financial analysis that illustrates that they will be able to cover their debt in addition to any potential scenarios or risks that may arise.

One unique aspect of Hawaii is that the State legislature has determined that co-ops can be funded using special purpose revenue bonds.[69] In June 2016, Governor Ige signed House Bill 2231 into law, which clarified the authority of the State government to issue bonds for the purpose of funding Cooperatives.[70] However, as with all special purpose bonds, there is a political condition

[69] Under the Hawaii State constitution, special purpose revenue bonds are "bonds payable from rental or other payments made to an issuer by a person pursuant to contract and secured as may be provided by law […]." They can only be authorized for specific facilities or assist certain entities. These entities include utilities that serve the general public. See "Types of Bonds Authorized by the Constitution, "Hawaii State Department of Budget and Finance," available at: http://budget.hawaii.gov/budget/about-budget/state-debt/.

[70] H.B. 2231, June 21, 2016, available at: http://www.hiec.co-op/docs_and_pdfs/Governor-David-Ige-Signs-HB-2231.pdf.

-- a two-thirds vote of the members of each house of the Legislature must authorize the use of special purpose revenue bonds.[71]

With the assurance of funding, the co-op may approach the incumbent utility and propose a purchase of utility assets. For the subsequent negotiation, the co-op should retain legal counsel, including third-party valuation and analysis. For example, in the NextEra merger, J.P. Morgan and Citigroup provided valuation and financial advisory services and Skadden, Arps, Slate, Meagher & Flom and Wachtell, Lipton, Rosen & Katz, two law firms, provided the legal support for HEI and NextEra, respectively. The process will involve multiple engagements and interactions between the Boards of HEI, the potential co-op, legal counsel, and financial advisors.

This negotiation process falls into multiple steps, including the signing of confidentiality agreements, exchanging of information, due diligence, an initial transaction and negotiation of high-level terms, and subsequent rounds of negotiations as needed. These steps should explicitly address all necessary approvals, including stakeholder or shareholder approval, regulatory approval, among others. These discussions and stipulations must eventually pass Board approval of each of the respective companies, before finally signing an agreement representing the final intent and terms of the acquisition.

This process could take approximately seven months total from raising capital to the final agreement. For reference, the entire process for NextEra to reach an agreement with HEI over the proposed merger transaction took approximately seven months from the initial offer by NextEra Energy in May 2014 to the final agreement in December 2014.[72] The purchase itself will be the costliest step, as illustrated in the cost acquisition analysis preceding this section, suggesting with little uncertainty a *high* magnitude of cost.

Box 4. RUS Electric Infrastructure Loans and Loan Guarantees Program

The RUS Electric Program provides loans and loan guarantees to finance construction or purchase of generation, transmission, and distribution facilities, or to support demand-side management, energy efficiency programs, and renewable energy systems. This includes on-lending for energy efficiency improvements and small-scale renewables on the customer side of the meter. RUS Electric Program has nearly 700 borrowers in 46 states, a $46 billion loan portfolio, and $5.5 billion annual loan budget. Its functional structure consists of three offices: Office of Loan Origination and Approval, Office of Portfolio Management and Risk

[71] For general legal authority governing state bonds, see Chapter 39A of the Hawaii of the Hawaii Revised Statute, "State Bonds," available at: https://www.capitol.hawaii.gov/hrscurrent/Vol01_Ch0001-0042F/HRS0039/HRS_0039-.htm.

[72] Form S-4 Registration Statement, NextEra Energy, January 8, 2015, available at: https://www.sec.gov/Archives/edgar/data/753308/000119312515005172/d846219ds4.htm.

Assessment, and Office of Policy, Outreach, and Standards. RUS Electric Program offers several loan products:

1. **Hardship Loans –** 5% interest rate for up to 35 years;

2. **Municipal Rate Loans –** Interest rates are based on the rates available in the municipal bond market, but borrowers are required to seek supplemental financing for 30% of their capital requirements;

3. **Treasury Rate Loans –** Interest rates at the prevailing market rates for US Treasuries; and

4. **Guaranteed Loans –** The Federal Financing Bank ("FFB"), an instrument of the Treasury Department, provides the loans, which are guaranteed by RUS. The interest rates on guaranteed loans are based on the market rate for a US Treasury of the same maturity, plus 0.125%.

The RUS also possesses several grant programs, which will not be covered in depth here; these include the Rural Economic Development Loan & Grant ("REDLG") program, the Rural Cooperative Development Grant ("RCDG") program, and High Energy Cost Grants.

Source: U.S. Department of Agriculture, "Electric Infrastructure Loan & Loan Guarantee Program," no date cited, available at: https://www.rd.usda.gov/programs-services/electric-infrastructure-loan-loan-guarantee-program.

4.2.11 Step 11: Regulatory Approval

Projected cost: High ($6 million-$7.5 million for all the HECO Companies)
Projected timeline: 1 year (7-18 months), subject to PUC decision-making

Following the approval of an agreement by both HEI and the co-op, the two parties must apply for a "Change of Control" in the utility to the PUC. This process will subject the proposed co-op to the scrutiny of the public and other interested stakeholders. As noted in Task 1.2.3, the PUC may evaluate the transaction through the standards developed through the cases of the KIUC acquisition and the HECO acquisition, particularly those related to public interest.

The application for a proposed "Change of Control" in the utility must undergo a thorough regulatory approval process. Some of the steps, key terms, and avenues of engagement for this process are outlined below:[73]

- **Application.** In its application, the applicants will typically outline the background of the applicants, envisioned benefits from the Change in Control, commitments to community

[73] For a further outline of the regulatory procedures, see Hawaii Administrative Rules Title 6, Chapter 61, Rules of Practice and Procedure Before the Public Utilities Commission," available at: http://puc.hawaii.gov/wp-content/uploads/2013/04/Chapter-6-61.pdf/.

stakeholders, "requested relief" (which includes approval of the application itself, and any other proposed regulatory changes), how the proposed transaction will meet the standards of Change in Control, whether certain costs will be passed onto consumers, among others concerns. Generally, as discussed in more detail below, the standard to review a proposed change of control is (1) whether the acquisition is reasonable and in the public interest and (2) whether the acquiring utility is fit, willing, and able to perform the service currently offered by the utility to be required.[74]

- **Motions to Intervene.** Interested stakeholder parties can subsequently submit motions to intervene[75] or participate without intervention[76] that indicate their intent to intervene or participate in the regulatory process. After parties have filed a motion to intervene or participate, the PUC will make a determination on the extent a movant may intervene or participate in the proceeding. Motions to Intervene or participate are required to be filed within twenty (20) days of the application for Change of Control.[77]

- **Information Requests.** Often, parties or participants may request information from the applicants to assist in their evaluation of the proposed the transaction. These parties may include special interest groups, other companies, and state government agencies, such as county governments, or Divisions and Departments of the Hawaii State government. The respondents typically must provide this information unless there is a basis to object to the request. If a party desires to keep certain information confidential, such party may request that the PUC issue a Protective Order.[78]

- **Testimony.** Parties and experts may provide oral or written testimony to the PUC, assessing certain characteristics of the proposed transaction. This testimony is frequently accompanied with exhibits, data, and other information that may shape the final decision of the PUC on the transaction.

- **Hearings.** While the PUC is not required by law to hold hearings, the PUC will likely hold hearings on the proposed transaction. These hearings can be "public listening" sessions in which PUC staff listen to the audience, or they can be "evidentiary hearings" in which experts or relevant parties will bring in materials to evaluate and offer their opinions on aspects of the transaction. These hearings are usually matter of public record (except for

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[74] *See* Order No. 33795, Dismissing Application without Prejudice and Closing Docket, filed in Dkt No 2015-0022 ("Order 33795"), on July 15, 2016, at 37, available at: https://puc.Hawai'i.gov/wp-content/uploads/2016/07/FINAL.ORDER_.33795.Docket2015-0022.pdf

[75] Hawaii Administrative Rules ("HAR") §6-61-55: "Intervention 1. (a) A person may make an application to intervene and become a party by filing a timely written motion in accordance with sections 6-61-15 to 6-61-24, section 6-61-41, and section 6-61-57, stating the facts and reasons for the proposed intervention and the position and interest of the applicant."

[76] HAR § 6-61-56(a): "The commission may permit participation without intervention."

[77] HAR § 6-61-57.

[78] HAR § 6-61-50.

confidential material) and are transcribed as transcripts that become available in the public docket.

- **Orders.** Throughout this process, the PUC will issue orders related to key issues that may arise. Finally, when the all the evidence has been received and the allotted time for deliberation and discussion has concluded, the PUC will evaluate the various arguments and evidence presented during the proceeding, and issue an order declaring its final decision and rationale.

Additional avenues for public engagement include:

- **Public Comments.** One avenue by which citizens can submit their perspectives is through public comment. These public comments can be emailed in and are recorded in the docket as a matter of public record.

- **Letters.** Letters to the PUC as another form of "public comment" is another avenue by which interested parties can reach out and voice their concerns. These letters are also typically recorded in the docket as a public record.

The length and cost of the regulatory proceeding are subject to the substance of the proceeding; in some cases, the PUC may find it justified to extend the timeline of decision-making. The costs can be substantial due to the legal and financial advising fees throughout this period. As previously noted, the transaction fees for KIUC were approximately $2.5 million total in 2002 or $3.4 million converted to 2017 dollars. For this reason, this step is classified as *high* cost. From our previous analysis, if we apply a 1.5% transaction fee to the total transaction value range of $4 billion to $5 billion, that yields approximately $6 to $7.5 million in transaction costs.

This timeline for approval can vary significantly. In the case of the HEI-NextEra merger, it took approximately 18 months from application to final order of the PUC to reach a decision, which rejected the merger. Although NextEra and HEI chose not to pursue this route, they could have possibly escalated to the courts for another determination. It is entirely possible that a smaller acquisition by a co-op could be less contentious, and therefore cost less and possibly be resolved more quickly. In the case of the KIUC-Citizens' Communications merger, it took approximately 7 months from the application in March 2002 to final approval in September 2002. For the purpose of providing a discrete timeline, this analysis suggests at least one year for regulatory approval.

One important issue is whether the co-op will continue to be regulated by the PUC. Recently, KIUC has sought to become progressively independent from PUC oversight over rate regulation,[79] which is similar to co-op regulation in other states. That said, even if the co-op seeks to exempt itself from PUC regulation, the co-op will likely still be subject to regulation regarding basic reliability and safety rules. Regulation of the co-op as a "public utility" under HRS Chapter

[79] KIUC Strategic Plan Update 2016-2030 (Adopted January 31, 2017), available at: http://website.kiuc.coop/sites/kiuc/files/documents/StrategicPlan_2017.pdf at 5, 7.

269 will also have to be considered to ensure that the co-op is sufficiently regulated in order to impose policy objectives such as renewable energy goals.[80]

4.2.12 Step 12: Workforce and Organizational Transition

Projected cost: High (>$250,000)
Projected timeline: 3 months minimum

After the application has been approved, the co-op could start to develop the workforce transition plan. Ideally, most of the staffing will be transferred over through a transition plan with the incumbent utility, but even with a transition plan, there are likely to be hiring needs. In the case of the Big Island, the Hawaii Island Energy Cooperative (HIEC) has expressed plans to hire and transition the legacy employees to the new co-op, which would also be the most likely strategy in other cases of co-op acquisition of HEI assets.

The Project Team noted that there might be different approaches or philosophies towards the workforce that could impact long-term hiring. For example, a local co-op may wish to hire greater numbers from its local community, rather than having workers from the mainland. Factors related to workplace culture between a co-op and an IOU may also have an impact on the willingness of the workers to stay over the long term.

Ideally, the Board should craft a strategic plan that:

- Defines the mission and values of the organization;
- describes targets and timelines for success; and
- outlines strategies to achieve those targets.

With this strategic plan, the Board should hire general managers that can support and implement the strategic plan. The general manager should then adjust hiring and workforce decisions as appropriate to ensure that the co-op can meet its long-term goals. This includes defining the structure of the organization and outlining responsibilities of departments and roles with clarity and specificity. These are all significant steps that will be costly, including multiple hires, disrupted work schedules, and time and energy spent by upper management. This is likely to be a cost that is *high* in magnitude.

4.2.13 Step 13: Transition Operations

Projected cost: High (>$250,000)
Projected timeline: Ongoing

The final step is to transition operations. If necessary, the co-op may wish to sign an agreement with the incumbent utility to determine timelines for implementation, particularly for

[80] See Section 4.5.4, below for additional discussion on this topic of regulation of the co-op as a public utility.

administrative tasks. For example, KIUC and Citizen's Communications signed a transition services agreement that encompassed a range of responsibilities, from budgeting to management of projects and assets. Over time, the co-op may need to readjust its strategy to accommodate unanticipated hurdles and changes. The history of KIUC, particularly its early turnover in CEOs and management, illustrates that the co-op may have to realign its business plan to adapt to changing circumstances.

4.3 Unique cost factors for achieving the 100% RE vision

The unique cost factors for co-ops are primarily tied to their status as entities that are run by the customers; therefore, the desires of the local population will be the major cost factor for achieving the 100% RE vision. This could either amplify or mute the cost of achieving 100% RE, depending on the extent of regulation, the desires of the local population, and the effectiveness of the management of the co-op. None of these factors, perhaps except for regulation, can be predicted with absolute certainty. This analysis does not provide a conclusion on whether the co-op model is better or worse at achieving the 100% RE vision, and instead outlines potential factors that may differentiate the co-op from other ownership models.

In terms of the desires of the members, the customer-owner structure of the co-op may allow the local community greater control over the technologies and approach towards the 100% RE target. In a co-op model, consumer-owners would have a direct influence over the deployment of various renewable technologies, each of which will possess their own unique tradeoffs (i.e. cultural and environmental concerns of geothermal resources, the aesthetic concerns of wind resources, grid cost recovery and defection concerns of rooftop solar, etc.). This creates opportunities to achieve the 100% RE vision in a manner that best aligns and reflects the opinions of island residents. However, this does also create a new avenue for objections to new renewable generation projects, potentially increasing the costs and timeline of achieving the 100% renewable energy target.

One unique characteristic of co-ops is their potential ability to secure low-cost capital through federal or Cooperative lending programs (which could allow for lower-cost generation resources, should utilities opt to develop and own these resources themselves,[81] as well as lower cost of necessary grid improvements). The rates of RUS loans and other potential sources for co-ops are near the long-term Treasury rate with a minor adder, which typically tends to be less expensive than the market-based rates. In contrast, IOUs may have to borrow debt at rates that incorporate the risk of their assets to a greater degree. These public sources of capital for co-ops may provide a source of low-cost funding to achieve the 100% RE vision. However, such funding is subject to a variety of conditions and requirements that will be elaborated on in the legal feasibility section.

In terms of public cost, one advantage of the co-op is that most of its excess operating revenues are returned to the customer-owners in the form of capital credits, therefore keeping the cash flows from the utility generally within Hawaii. In contrast, the equity cash flows of an IOU return to investors who may or may not be within Hawaii. In terms of a public cost-benefit for the

[81] As a point of reference, KIUC owns 25.5 MW of the 83.9 MW of renewable resources (30%) currently active on the island. KIUC website, http://website.kiuc.coop/renewables (accessed October 31, 2018).

jurisdiction of Hawaii, with all other factors held constant, this may suggest that the served population would experience greater returns under a co-op system than a system owned by investors. On the flip side, however, there will be significant upfront costs to acquire and operate the system.

One final potential factor for achieving the 100% RE goal is the future of co-op rate regulation under the PUC. For examples, unregulated co-ops could possibly adopt new and innovative technologies more quickly. However, this does have the downside that absent outside intervention, the co-op may be more prone to incurring significantly higher rate increases to support these costly new technologies or perhaps risky experiments in failed innovation. A lack of rate regulation could thus contribute to either a rise or decrease in the cost of achieving the 100% RE target, subject to a variety of intervening factors.

4.4 Conclusion on steps and associated cost

The formation of a co-op can broadly be characterized into the phases of (1) establishment, (2) purchase, (3) regulatory approval, and (4) subsequent operation. The following briefly summarizes the timeline and costs of each of these phases. For a thorough overview of these phases, please see Figure 20. Note that these phases are not discretely divided in terms of timeline. Many steps will overlap and are co-dependent on the successes of others.

1) **Establishment.** The initial establishment of the co-op encompasses initial leadership discussions, membership recruitment and engagement, incorporation and bylaws drafting, and the formation of provisional and steering committees. While leadership discussions, incorporation and bylaws drafting, and formation of committees are not costly, they are complicated and of utmost significance, because they implicate all the subsequent steps.

   The costlier characteristics of initial establishment involve membership outreach and feasibility studies for the purchase of the utility. The membership outreach should be thorough and extensive and may require a significant effort from volunteers and marketing. The feasibility studies should be thorough, comprehensive, and rigorous, and require consultants or contractors with the required capabilities and expertise.

   This phase should span about six to nine months total, with some of the tasks, such as membership recruitment spanning longer as necessary for success.

2) **Purchase**. The purchase of the utility encompasses a range of tasks such as the development of business plans, the raising of capital, negotiation over the purchase of the assets, and closing the deal. Many of these steps are co-dependent. For example, the business and feasibility analyses will be necessary to persuade financiers the capitalize the project. Negotiations will be constrained by the desires of financiers. Finally, closing the deal is subject to the subsequent step of regulatory approval.

   The purchase of the co-op is by far the costliest phase since it involves the actual purchase of the utility. Based on our discounted cash flow, comparable trading, and comparable transactions analysis. The total transaction value may be greater than the $4.3 billion suggested in the NextEra merger proposed in 2014. Our analysis indicates that the range

for the purchase of the utilities might encompass $20.55 to $30.20 per share, or $4.1 billion to $5.1 billion for all the HECO Companies.

This phase can encompass approximately nine months in total with significant variation based on the nature of the transaction and legal and regulatory issues that may arise.

3) **Regulatory approval**. As previously noted, the purchase of the co-op hinges on regulatory approval. Often, much of regulatory approval depends on the thoroughness of the steps taken prior to the regulatory proceeding in the establishment and purchase phases. For example, if stakeholder outreach and engagement are not genuine and thorough, there is a greater likelihood of objections throughout the regulatory approval process. If the financing has not been thoroughly vetted for sustainability, the PUC is likely to reject the merger, as the case of KIUC's initial offer for Citizens Communications in 2000.

   Based on an empirical analysis of prior transaction costs, the potential transaction costs involved in purchasing all the HECO Companies could range from $6 million to $7.5 million, based on transaction values from $4 billion to $5 billion, if we assume that the transaction costs are 1.5% of the total transaction value.

   This phase is potentially the longest of all the phases and will overlap significantly with the purchase phase. An approximate estimate is 12 months but can vary significantly.

4) **Operation**. Finally, the subsequent operation is costly, but it also allows the co-op to finally earn a return on its investment. Operations will likely commence approximately 2 years after the initial conception of the co-op. The costs for this step are also the most indeterminate, based on the vision of the co-op, the number of employees transitioning in and out of the company, and the competency of management. The employee requirements of a co-op entity will be described in subsequent tasks.

The establishment of a co-op is not a light undertaking due to the potential cost of acquisition, potential legal challenges, and ongoing deliberations necessary for success. However, the model has experienced success and has translated into benefits for consumers in Hawaii, as evidenced by the establishment of KIUC and its progressive decrease in electricity rates over time. That noted, the experience of KIUC is not necessarily an indicator of future results. The co-op model also possesses unique characteristics – low-cost capital, consumer control, and differing regulatory requirements – that implicate its ability to achieve the 100% RE vision of Hawaii.

4.5 Legal Considerations

In the process of forming a co-op, the leadership and members should comply with all relevant federal, state, and local laws and regulations that define and regulate the prospective co-op. Some of the prior "steps" have touched on the legal requirements of establishing a Cooperative, such as the provisions for incorporation and bylaws under Hawaii State statute. This section will further outline and elaborate on the requirements in U.S. federal tax law, the Code of Federal Regulations (CFR), Hawaii statutes, and their effects on co-op organization and operation.

KIUC's formation and acquisition of Kauai Electric provides a prior case example for co-op acquisition and operation of electric utility assets in Hawaii. However, unlike with State courts,

the Hawaii PUC is only bound by qualified role of *stare decisis*, so this case example may not be binding to the PUC, but it may serve as a precedent.[82] That noted, this section will clarify the legal requirements of the co-op and whether additional regulatory changes, if any, are necessary to support the establishment of the co-op model on any of the islands in Hawaii. This analysis concludes that while alterations in regulation or legislation are not *necessary* to form the co-op, there are opportunities to craft regulations that can support vulnerabilities for co-op formation on Hawaii islands, particularly for instances in which the co-op would serve a nonrural area.

4.5.1 Legal Issues Pertaining to the Establishment of the Cooperative Model

The following section will describe the general legal requirements for co-op formation. It will proceed by outlining the principles embedded in the definition of a Cooperative in U.S. tax law, the regulation of co-ops in Hawaii statute, and the requirements for nonprofit 501(c)(12) status. As co-op proponents seek to establish respective co-ops in their jurisdictions, they should seek to adhere to the principles outlined below to ensure that the entity will be legally classified as a co-op and have access to its associated benefits.

4.5.1.1 Legal Requirements of a Cooperative Per U.S. Tax Law

In Puget Sound Plywood, Inc. v. Commissioner (1966), the U.S. Tax Court defined a Cooperative as: "[…] an organization established by individuals to provide themselves with goods and services or to produce and dispose of the products of their labor. The means of production and distribution are those owned in common and the earnings revert to the members, not based on their investment in the enterprise, but in proportion to their patronage or personal participation in it."[83] The case further outlined the principles of a Cooperative as follows:[84]

1. **Democratic Control**. The organization must periodically hold democratically conducted meetings with members, with election of officers must be on a one member, one vote basis. In Etter Grain Company, Inc. v. United States (1972), the United States Court of Appeals for the Fifth arrived at a similar definition, stating that a Cooperative must operate "according to a model of a widely-based participatory democracy in which all the members are able to exercise a franchise of equal strength."[85]

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[82] Application of Hawaiian Elec. Co., Inc., 81 Hawai`i 459, 467, 918 P.2d 561, 569 (1996), as amended (July 11, 1996) ("PUC's adjudicatory powers can have a precedential effect and be used to guide the PUC in future decisions.")

[83] Puget Sound Plywood, Inc. v. Commissioner, 44 T.C. 305 (1966), acq. 1966-2 C.B. 6.

[84] For an overview of the legal definition of Cooperatives, see Tyrus Thompson, "Introduction to Cooperatives," October 21, 2011, Presentation, American Bar Association, available at: https://www.americanbar.org/content/dam/aba/events/taxation/taxiq-fall11-thompson-intro-co-ops-slides.authcheckdam.pdf.

[85] Etter Grain Company, Inc. v. United States, 462 F.2d 259, 263 (5th Cir. 1972).

2. **Operation at Cost.** The organization must allocate all excess operating revenues among the members. As the Tax Court explained in Ford-Iroquois FS, Inc. v. Commissioner (1980) further explained, operation at cost is "rendering economic services, without gain to itself, to shareholders or to members who own and control it."[86]

3. **Subordination of Capital.** Those who contribute capital neither control the operations nor receive most of the pecuniary benefits. In practice, this has meant that members elect the board of directors, rather than equity investors. The members control and own the savings or monetary benefits rather than the nonmember shareholders or equity investors. This has traditionally meant limitations on dividends and returns on capital.

While the definition of the co-op in Puget Sound Plywood, Inc. v. Commissioner tends to be most frequently cited by the IRS and in subsequent case law, additional legal definitions of co-op in other treatises comport with these definitions and qualifications. For example, see "The Organization and Operation of Cooperatives," by Israel Packer, which provides a legal treatise on the definition and operation of Cooperatives that aligns with the definitions outlined above. These three principles tend to guide the overarching legal framework by which other entities determine whether an entity and its activities can legally qualify as those of a "Cooperative," and serve as the legal foundation for determining whether an entity is a Cooperative.

4.5.1.2 Legal Requirements of a Cooperative Under Hawaii Law

In Hawaii, co-ops are guided by HRS, Chapter 421C on Consumer Cooperative Associations, with an exception of superseding decision-making by the PUC, which may waive or exempt legal or regulatory requirements of a co-op under HRS § 269-31(b).[87] According to HRS § 269-31(c), the co-op must be:

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[86] Ford-Iroquois FS, Inc. v. Commissioner, 74 T.C. 1213, 1219 (1980), also see Buckeye Power, Inc. v. United States, 38 Fed. Cl. 154, 161 (1997).

[87] HRS § 269-31(b) provides:

> Notwithstanding any provision of this chapter or any franchise, charter, law, decision, order, or rule to the contrary, the public utilities commission, sua sponte or upon the application of an electric Cooperative, may waive or exempt an electric Cooperative from any or all requirements of this chapter or any applicable franchise, charter, decision, order, rule, or other law upon a determination or demonstration that such requirement or requirements should not be applied to an electric Cooperative or are otherwise unjust, unreasonable, or not in the public interest. Notwithstanding the above, the public utilities commission and the consumer advocate shall at all times consider the ownership structure and interests of an electric Cooperative in determining the scope and need for any regulatory oversight or requirements over such electric Cooperative. To the extent any other provision of this chapter or any franchise, charter, law, decision, order, or rule is contrary to or otherwise conflicts with this section in any manner, the provisions of this section shall govern and apply.

- owned by its members;[88]
- formed pursuant to HRS, Chapter 421C;
- operated on a not-for profit basis;[89]
- authorized pursuant to a legislatively granted franchise or other legislative authority to provide electricity services to its members or a designated service area; and
- governed by a board of directors who are members of the co-op and elected according to applicable bylaws.[90]

HRS Chapter 421C further defines a Cooperative as an entity in which

- each member has one vote and only one vote, except for cases of provisions for member organizations;[91]
- the maximum rate of return for membership capital is limited; [92] and
- the allocation of net savings is allocated in a manner that benefits the general welfare of all members or is made in proportion to their patronage.[93]

As written, these definitions conform with the definition of co-ops in U.S. Tax Case Law and the Internal Revenue Code (IRC), with some additional stipulations that clarify voting in the case of member organizations, and how net savings can be allocated to serve the purpose of the co-op.

Box 2 and Box 3 have highlighted the legal requirements for incorporation and bylaws, and thus will not be repeated here. Additional issues touched upon within Chapter 421C include specifications on the removal of directors, removals of officers, voting, limitations on interest-

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[88] *See also* HRS § 421C-1.

[89] *See also* HRS § 421C-19.

[90] *See also* HRS § 421C-12.

[91] HRS § 421C-14 further clarifies the procedure by which member associations can allocate a vote. These organizations must be organized on a Cooperative basis (see the three standards outlined above) and can apportion votes according to number of individual members or the size of dollar volume of direct transactions between the member and secondary association.

[92] HRS § 421C-19 further clarifies this limit. Interest-dividend interest on share or membership capital shall not exceed the current annual Consumer Price Index percentage increase, or eight per cent, whichever is greater. Total interest-dividends distributed for any single period shall not exceed thirty per cent of the net savings for that period.

[93] HRS § 421C-25 further clarifies the allocation and distribution of net savings, which includes allocation to a surplus fund, interest-dividends, an educational fund, or a patronage fund, with specific percentages and stipulations.

dividends, issuance of stock, membership, expulsion, bookkeeping, among many other topics that affect in much greater detail the bylaws, management, and operation of the co-op itself. These additional topics, if followed, also closely align with the legal requirements of Cooperative nonprofit status as per IRC 501(c)(12), which is described in the following section.

Generally, none of these legal requirements in the Hawaii Revised Statutes form de facto constraints on the ability of co-ops to acquire and operate electric utility assets on any of the islands, nor do they outright contradict other sources of co-op law, such as those stipulated in IRC. It is not necessary to make amendments to HRS, Chapter 421C to accommodate prospective co-op entities on each of Hawaii's islands.

4.5.1.3 Legal Requirements of Cooperative Nonprofit Status Per IRC 501(c)(12)

One potential benefit of co-ops is their ability to organize as nonprofits under U.S. federal tax code. In the Miscellaneous Revenue Act of 1980, the U.S. Congress included provisions that allowed electricity co-ops to qualify for IRC 501(c)(12) status,[94] which exempts them from federal income tax.[95] This ability to achieve nonprofit status implicates their financial sustainability over the long-term. It also can become a significant factor in determining the "fitness" of the co-op to undertake utility responsibilities during the PUC proceeding that governs the transfer of utility assets. Achievement of this status requires that:

1. 85% of income must come from members for the sole purpose of meeting losses and expenses each year;

2. the co-op must meet the organizational and operational requirements and revenue rulings relevant to the co-op entity; and

3. the entity must provide one or some of a designated list of qualifying activities.

Each of these provisions, or tests during an audit, is clarified through subsequent legal guidance. In the case of the **income test**, the IRS has specified that income generally means gross income, which is defined as gross receipts less the cost of goods sold, trade discounts, allowances of goods sold and refunds on returned goods.[96] However, Cooperatives do not have to deduct the costs of goods sold from gross sales to calculate the 85-percent member income test.[97] In addition, this income test must be calculated annually, so it is possible that the entity under consideration could not qualify for 501(c)(12) in one year, but do so in the following year. In the case in which member

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[94] Miscellaneous Revenue Act of 1980, P.L. 96-605, section 106(a), 94 Stat. 3523 (1980).

[95] Internal Revenue Manuals, Part 7, 7.25.12, Organizations Exempt Under IRC 501(c)(12).

[96] Rev. Rul. 80-86, 1980-1 C.B. 118.

[97] 58 Fed. Reg. 25587.

income falls below the 85-percent threshold, the organization is no longer exempt and must file a corporate tax return.[98]

Moreover, each item of income is classified as member income, nonmember income, or excluded income. As for the definition of "member income," the income must be provided through entities that can be defined as members and must be paid for the list of designated activities. If the income does not fall into this definition, it is considered either "nonmember income," or "excluded income" if it falls within one of the activities described below. To be considered a member, an entity must be able to participate in the co-op's management and share in patronage capital.

For excluded income, Congress excluded through subsequent Acts the income for electricity Cooperatives from loan prepayment, open access transactions that are approved or accepted by FERC, nuclear decommissioning transactions, or any asset exchange or conversion transaction.[99] The IRS also clarified that qualified co-op entities could potentially exclude income from qualified pole rentals.[100] Government grants from either state or federal agencies may also be excluded as income, provided that such grants meet certain requirements.[101]

Finally, examples of nonmember income include items such as interest from nonmember sources, rental income, the installment sales of assets, income from nonmember patrons, and dividend income from for-profit entities that are not members.[102]

With regards to the **organizational and operational test**, in Rev. Rul. 72-36, 1972-1 C.B. 151, the IRS elaborated on the organizational and operational requirements of the co-op to become a 501(c)(12) entity.[103] Note that these requirements generally comport with the requirements present in the HRS , Chapter 421C. These requirements include:

- Adequate records of each member's rights and interests in its assets;

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[98] Rev. Rul. 65-99, 1965-1 C.B. 242.

[99] Technical Miscellaneous Revenue Act of 1988, P.L. 100-647, section 2003(a)(2)(C)(ii), 102 Stat. 3598 (1988).

[100] IRC Section 501(c)(12)(B)(ii) and (C)(i).

[101] These requirements include: The grant must become a permanent part of the co-op's working capital structure; it cannot be compensation for a specific quantified service for the transferor by the transferee; it must be bargained for; it must result in benefit to the transferee in an amount commensurate with its value; and it must typically be used in or contribute to the production of additional income and its value assured in that respect.

[102] See the IRS, "Audit Technique Guide – Local Benevolent Life Insurance Association, Mutual Irrigation and Telephone Companies and Like Organizations – IRC Section 501(c)(12)," no date cited, available at: https://www.irs.gov/pub/irs-tege/atg_local_ben_life_ins_assn.pdf.

[103] Rev. Rul. 72-36, 1972-1 C.B. 151.

- Distribution of any savings to members in proportion to the amount of business done with them based on the "operation at cost" principle;

- No retention of more funds than necessary to meet current losses and expenses;

- No forfeit of a member's right and interest in the organization upon termination of membership;[104]

- Distribution of the gains from the sale of any appreciated assets to all persons who were members during the period that the organization owned the assets, in proportion to the amount of business done by the members during that period.

Finally, for the **"activities" test**, electrical service is included as one of these designated activities, so co-ops that provide this service should qualify for this test. However, the IRS outlined some specific exclusions that are not included in qualifying activities for electric utilities, and therefore would not count as member-based income. Activities that do not count include:

- Financing the purchases of electrical appliances;[105]

- Sale by a nonprofit Cooperative of electrical materials, equipment, and supplies, as well as the provision of equipment manufacturing, repair, and testing services to its members;[106]

- The sale of propane by trucks.[107]

None of these tests suggest any reason that there might be de-facto hurdles to the ability of any co-op on Hawaii's islands to achieve tax-exempt status. Plausibly, co-ops on all the islands should be able to achieve Cooperative status in terms of federal tax law if they are able to achieve the principles and stipulations outlined above, some of which are required by virtue of the requirements in HRS , Chapter 421C. Note that these requirements do not require that the entity in question register as a Cooperative under State statute, although Hawaii does have statute that governs the existence of Cooperatives. This statute, as described above, does specifically outline that the entity should operate on a nonprofit basis, and achieving 501(c)(12) status is one means of demonstrating nonprofit status via IRC.

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[104] Rev. Rul. 78-238, 1978-1 C.B. 161.

[105] Consumers Credit Rural Electric Co-op. Corp. v. Commissioner, 37 T.C. 136, 143 (1961), aff'd 319 F.2d 475 (6th Cir. 1963).

[106] Rev. Rul. 65-201, 1965-2 C.B. 170.

[107] Rev. Rul. 2002-54, 2002-2 C.B. 527. Many co-ops have for-profit subsidiaries that provide propane sales; according to IRS Revenue Rulings, these would not qualify as a designated activity of a Cooperative.

4.5.2 Legal Issues Pertaining to Federal Funding

The following section outlines the key legal considerations involved in securing funding for prospective co-ops from RUS. This paper will not cover all the funding sources available to co-ops. Note that co-ops do not *necessarily* have to be RUS borrowers. However, this section will devote its analysis to RUS Electricity programs, given their significant prevalence as both a low-cost funding source for rural co-ops, their relationship to other funding sources including potential funding from the Cooperative Finance Corporation (CFC), and their unique status as a government-based funding source, and their historical significance in contributing to demonstrating "financial fitness" during regulatory approval in Hawaii due to their low interest rates.[108] Furthermore, this section will situate the steps involved in co-op formation in the context of the legal requirements for RUS funding.

4.5.2.1 Legal Definitions of "Rural Areas"

Generally, RUS funding is available only for those projects or entities that serve areas that qualify as "rural." As explained in Task 1.2.3, this poses some limitations on funding co-ops on the islands with larger populations, such as Oahu, Maui, the Big Island, and even Kauai.[109] With regards to RUS funding, Electricity Program loans are generally only available for rural areas, with "rural areas" defined as *an area other than* a city, town, or unincorporated area of more than 20,000 in population,[110] which would allow for island-wide Cooperatives on Molokai and Lanai, both of which have populations less 20,000.

The definition of "rural" or "rural area" in 7 U.S.C. 1991(a)(13)(G) includes a provision that states that "within the areas of the County of Honolulu, Hawaii . . . the Secretary [of the U.S. Department of Agriculture] may designate any part of the area as a rural area if the Secretary determines that the part is not urban in character, other than any area included in the Honolulu Census Designated Place[.]"[111] Currently, Eligible Borrowers for the State of Hawaii includes "all areas within the State are considered rural, except for the Honolulu CDP [Census Designated Place] within the County of Honolulu.[112] This suggests that RUS could fund Cooperatives on all the islands other than Oahu.

4.5.2.2 Legal Requirements for Loan Submission and Evaluation

To receive funding from RUS, co-op applicants must meet the legal requirements outlined in the Code of Federal Regulations. During this period, the steps taken to evaluate the co-op's feasibility

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[108] RUS funding can serve as a catalyst for available short-term loan funding from the CFC, including bridge loans. See Letter from the National Rural Utilities Cooperative Finance Corporation to the Office of the Comptroller of the Currency, Board of Governors of the Federal Reserve System, June 21, 2011, p. 3, available at: https://www.fdic.gov/regulations/laws/federal/2011/11c47ad74.pdf.

[109] Population of these islands are all greater than 20,000. See www.census.gov.

[110] 7 CFR 1710.2, emphasis added.

[111] 7 U.S.C. § 1991 (a)(13)(G).

[112] *See* Guaranteed Loanmaking and Servicing Regulations, 81 FR 35984-01; 7 CFR. § 4279.108(c)(4).

will undergo scrutiny by RUS. This includes any engineering analysis, financial analysis, and the business plan formation that are been described in the previous steps. To provide a loan, RUS must reach its required findings as outlined in 7 CFR § 1710.151 and summarized in Box 5 below.

Box 5. Required Findings for RUS Electric Loans

The following bullet points outline the required findings of the Administrator before approving an electric loan or loan guarantee. This evaluation and decision must be supported by the co-op's documentation in its application. With regards to the below, some of the notable requirements include stipulations on improvements for non-rural areas. This could bear implications for co-ops, particularly on the more populous islands such as Maui and Oahu, that might intend to serve areas that might not otherwise qualify as rural.

1. **Area Coverage:** The borrower must provide adequate electricity service to the widest practical number of rural users during the life of the loan;

2. **Feasibility:** The loan is feasible, will be repaid on time according to its terms, which can be subject to further revaluation by the Administrator if any significant changes occur;

3. **Security:** RUS will possess first lien on the borrower's total system or other adequate security, and financial and managerial controls will be outlined in all documents;

4. **Interim Financing:** If RUS funding will be replacing interim funding, there must be satisfactory evidence that the funding was used for its intended purpose;

5. **Facilities for non-rural areas:** If there are funds are used to provide any benefits for non-rural areas, the borrower must provide satisfactory evidence that such funds are necessary and incidental to supporting electrical service for rural beneficiaries;

6. **Facilities to be included in the rate base:** In regulated states, the borrower must provide an opinion of counsel that the state regulatory authority will not exclude from the rate base any of the facilities included in the loan request.

Source: 7 CFR § 1710.151

According to Federal Code, the primary support documentation that *must* be included with any loan application includes:

- **Load Forecasts:** The document provides an understanding of future system loads, the factors influencing those loads, and future load estimates. It provides a basis for projecting kWh sales and revenues, and for engineering estimates of plant additions required to meet

the forecasted loads.[113] Ideally, such load forecasts will have been developed through the engineering feasibility analysis and contextualized through the market analysis.

While all utilities must submit a load forecast at the time of application if their loan is for an amount greater than $50 million (which would likely be all prospective co-ops), for those utilities with a total utility plant of greater than $500 million, such utilities are required to keep an ongoing and updated load forecast, which could potentially distinguish the operational requirements of a co-op that seeks to cover a larger island such as the Big Island, Maui, or Oahu versus a co-op that covers Molokai or Lanai.

- **Construction Work Plans:** This document specifies the construction and capital improvements necessary to meet the load forecast while maintaining reliability and quality. All utilities, regardless of size, must maintain up-to-date long-range engineering plans approved by their boards of directors. These Construction Work Plans must adhere to the various standards and procedures outlined by the RUS in its associated regulations.

- **Long-Range Financial Forecasts:** This document should illustrate the due diligence of the board and management to ensure the financial sustainability of the co-op. It should also include the projected financial outcomes of any future planned actions. In some cases, RUS may require a sensitivity analysis on a case-by-case basis, considering the number and type of large power loads, projections of future borrowings and interest, projected loads and revenues. This may be another distinguishing factor between co-ops that serve rural versus more densely populated contexts.

- **Environmental Studies Report:** This report evaluates the environmental impact that the construction work plans may have on the environment. Depending on the intended action and outcomes, the RUS may require additional environmental studies.

In all cases, any necessary state regulatory approvals must be made before the approval of any loans that are greater than $25 million, require an Environmental Impact Statement, or for any demand side management, energy conservation programs, and on and off grid renewable energy systems. As such, the legal feasibility of regulatory approval of a co-op acquisition informs the legal feasibility of any RUS funding for all the co-op entities under consideration.

4.5.2.3 Legal Requirements for Operations and Management

There are numerous other requirements for borrowers outlined in federal regulation that span a variety of topics. These cover the scope of the utility activities, ranging from construction, employment, and workplace practices. More broadly, they intend to link and streamline co-op operations with broader federal law. The following outlines the standards that are applicable to the operations of the borrower, both in terms of workforce maintenance, as well as other relevant standards and considerations:

[113] 7 CFR § 1710.152.

- *Nondiscrimination Policies:* The RUS requires all Electric borrowers to conform with principles related to Title VI of the Civil Rights Act, Section 504 of the Rehabilitation Act, and Age Discrimination Act. This generally suggests no discrimination in rates, services, membership applications, employment practices, consumer financing programs, or in bidding or negotiation process.[114]

- *Lobbying:* Borrowers must comply with relevant restrictions on lobbying activities;[115]

- *Drug-free Workplace:* Borrowers must comply with the Drug Free Workplace Act of 1988;

- *Insurance and Fidelity Coverage*: Borrowers must have adequate insurance and fidelity coverage as outlined in the relevant statutory code;

- *Debarment and Suspension:* Borrowers must comply with certain requirements on debarment and suspension;

- *Uniform Relocation Act*: In cases that involve relocation of residences or business, borrowers must comply with the requirements of the Uniform Relocation Act.

These legal requirements are unsurprising, given that RUS is a federal entity and will thus seek to ensure that its funding conforms with the existing rules and regulations of the federal government. None of these eliminate the possibility of the co-op, although they may lead to more scrutiny over the internal metrics of the organization.

4.5.2.4 Assessment of RUS Lending Requirements and Regulatory Opportunities

RUS lending requirements may have differential effects on prospective co-ops on each of the islands. Some co-ops might not be able to secure RUS funding if they seek loans for populations that are not in rural areas, although they may be able to secure funding from other sources. Based on the size of the loan, additional requirements may be imposed, such as ongoing updates of load forecasts. Finally, these loans require substantial documentation and requirements after loan approval that impose an ongoing workload for all co-ops, regardless of size or location.

Again, none of these regulations de facto exclude the possibility of a co-op on any of the islands. However, they do present opportunities to craft regulations that might support entities that might not otherwise be able to acquire federal funding due to limitations on rural funding. Some approaches for this case are regulations that mitigate certain risks of operating in urban environments or leveraging the provisions of HB 2331 to support state government funding for co-ops seeking to operate in urban environments.

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[114] Rural Utilities Service, "Nondiscrimination Among Beneficiaries of RUS Programs," Bulletin 1790-1, January 28, 2000, Available at: https://www.rd.usda.gov/files/UEP_Bulletin_1790-1.pdf.

[115] 7 CFR 3018.

4.5.3 Legal Issues Pertaining to Regulatory Approval of Utility Purchase

As noted in Task 1.2.3, the transfer of utility assets from an IOU to a Cooperative is subject to PUC approval under its statutory authority outlined in HRS § 269-7, -17, and -19.[116] The PUC would likely apply criteria similar to the criteria applied in the KIUC and NextEra matters. In the proposed NextEra acquisition, the PUC followed a test under HI Rev. Stat § 269-19 that it had earlier used to evaluate the KIUC transfer: "(1) whether the acquiring utility is fit, willing, and able to perform the service currently offered by the utility to be acquired, and (2) the acquisition is reasonable and in the public interest."[117] However, the approach for applying these two standards has transformed since the KIUC acquisition.[118] This is the primary test applied to any proposed acquisition of a Hawaii public utility.

The following sections will outline the concerns pertaining to these standards and how those concerns are addressed. It will begin by outlining the Rules of Practice and Procedure before the Public Utilities commission, as outlined in Chapter 6-61 of the Hawaii Administrative Rules. It will then focus on both standards in turn, highlighting the key issues that may affect the final decisions of PUC. In doing so, it will illustrate that legal feasibility cannot be evaluated independent of the substantive characteristics of the merger under consideration; as in the case of the KIUC acquisition of Kauai Electric, and the shuttered NextEra-HECO merger, the financial, operational, technical characteristics of the entities and the transaction will be subject to PUC scrutiny for regulatory approval.[119]

For this analysis, we only consider the scenario in which a friendly transaction occurs, meaning such a transaction is not opposed by HEI. As noted in Task 1.2.3, there is a theoretical possibility of the state government utilizing eminent domain to acquire IOU assets and transfer them to a co-op, which would likely spark a debate over the "public interest" in acquiring and transferring the assets of IOUs to Cooperatives. It would also likely spark an eminent domain court proceeding and extensive litigation. The following analysis will focus on the procedures and legal

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[116] Depending on the nature of the transaction, different statutory authorities could be implicated. Generally, HRS § 269-19 applies to the mergers and consolidation of public utilities. Although HRS 269-19 could be read as only transactions between public utilities, it was applied in the KIUC docket and the HECO/NextEra case despite in both cases, neither acquiring entity was a Hawaii "public utility" under HRS Chapter 269. The PUC also has broad investigative powers under HRS § 269-7, which allows the PUC to examine, among other things, the condition of each public utility, the value of its physical property, the issuance of stocks and bonds, and the relationship the public utility has with others. Lastly, PUC approval is required under HRS § 269-17, for any public utility to issue stock, bonds, notes, and other evidences of indebtedness. Thus, if the proposed transaction involves any of the foregoing, then PUC approval must also be sought under HRS § 269-17. Lastly, HRS 269-17.5, applies to transactions where more than 25% of the issued and outstanding voting stock of a public utility is held by a foreign corporation, single nonresident alien, or held by any person. If the transaction meets these criteria, it would be subject to PUC's prior approval.

[117] Order No. 33795 at. 34-35.

[118] While there were other standards included in the NextEra decision, these additional standards – such as concerns of the financial size of the HECO Companies – were tailored to the context of NextEra and IOUs, bearing less relevance for prospective co-ops.

[119] *See, e.g..*, Order No. 33795 at 45-260.

standards that will arise in the context of PUC approval, which likely would be relevant in either a friendly or hostile acquisition, given that in either case, the PUC retains the authority under HRS §§ 269-7, -17, -17.5, -19, and other applicable law, to approve such transfers.

4.5.3.1 Rules of Practice and Procedure

Generally, all docket proceedings before the PUC follow the guidelines established in HAR § 6-61, or the "Rules of Practice and Procedure before the Public Utilities Commission," and HRS, Chapter 91, on "Public Proceedings and Records." Subchapters 1 through 4 of HAR § 6-61 outline General Provisions, General Requirements in Proceedings before the Commission, Agency Hearing Procedures, and Intervention, Participation, Protest, and the role of the Consumer Advocate. Subchapter 6 contains information relevant to Applications and Petitions generally, and Subchapter 7 contains information relevant to Applications for Certificates of Public Convenience and Necessity or Permits. While this analysis will not describe the minutia of HAR Chapter 6-61 that govern the processes of agency hearings, it will emphasize that HAR Chapter 6-61 provides the legal basis for the procedural decision-making of the PUC and interested parties.

Subchapter 10 provides details on the form and content of applications that would be required to apply for approval of a proposed co-op. Subchapter 10 of HAR 6-61 covers "Applications to Sell, Lease, or Encumber Public Utility, Water or Motor Carrier, Property or Rights; to Merge or Consolidate Facilities; or to Acquire Stock of Another Public Utility, Water Carrier, or Other Regulated Company Subject to Commission Jurisdiction."[120] This subchapter describes the general characteristics of an application for such merger or acquisition activity, as well as required information. This includes a description of the transaction, the property involved, the character of the business performed, the rationale for entering the transaction and the justifying facts, the agreed purchase price and terms of payment, and accompanying documents, including financial statements and a proposed deed of sale.

As for the actual docket proceeding, the nature of proceedings varies according to the characteristics of the transaction. For example, the procedure for the KIUC Acquisition in 2002 is outlined in Box 6; it was arguably more straightforward than the proposed NextEra merger in 2015, given that it had been preceded by a failed initial docket proposal. Thus, the ensuing alterations to the agreement had already incorporated some of the concerns of the community, and it had Consumer Advocate's support and the County in partial support.[121]

In the case of the NextEra Merger, the procedure was a "contested case" procedures under HRS, Chapter 91.[122] The PUC held proceedings pursuant to those procedures, in which the PUC stated

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[120] HAR 6-61 Subchapter 10. http://puc.hawaii.gov/wp-content/uploads/2013/04/Chapter-6-61.pdf

[121] Decision and Order No. 19658, filed in Docket No. 02-0060, on September 17, 2002 ("KIUC D&O") at 19 and 24

[122] Order No. 33795 at 38.

that all parties were afforded an opportunity for hearing after reasonable notice.[123] Moreover, the PUC directed the Parties involved to submit to the PUC a procedural order for the formal hearing process, and utilized these submissions as part of the basis of its eventual determined procedure.[124]

In part from regulations governing public proceedings, the orders and decisions of the PUC, and the contentious nature of the transaction itself, the NextEra merger docket was subject to the suggestions of various parties. The PUC addressed numerous motions suggesting alterations to the procedure, including extensions and motions to merge the docket with other preexisting dockets. This contrast suggests that legal feasibility, which is a function of challenge and debate during the docket process, reflects in part general community and political acceptance. Box 7 provides a contrasting example of the regulatory process for the NextEra-HECO merger.

Box 6. The Regulatory Procedure for the KIUC Acquisition

While historical process does not constitute precedent, the regulatory schedule included in the procedural schedule of the docket measure for the KIUC and Citizens Communication Company application in 2002 provides an illustrative approach towards the regulatory procedure for a change in control for a prospective co-op acquisition of utility assets. The process for the KIUC acquisition encompassed these steps in the following order:[125]

[123] *See* Order No. 33041, Order Establishing Forma Evidentiary Hearing Dates and Location, filed in Dkt No 2015-0022, on August 4, 2015.

[124] HRS § 91-9.

[125] Hawaii Public Utilities Commission, Procedural Order 19397, filed in Docket No. 02-0060, on Mar 31, 2002, as amended by Order No. 19530, filed in Dkt No 02-0060, on August 21, 2002.

Date	Action
3/15/02	Initial submission of application
4/09/02 5/08/02	Submission of Information Requests (IRs) by the Consumer Advocate, the County, other relevant entities (i.e. the Department of the Navy)
5/15/02 5/22/02	Responses to IRs by the applicants (approximately three weeks after the submission of the IR under consideration)
5/22/02	Public Hearings
5/29/02 7/5/02	Continued IRs by all entities and Responses to IRs
7/10/02	A meeting to discuss responses to discovery and any potential concerns that may have arisen from the review of the responses to discovery
7/19/02	Preliminary Position Statements
8/2/02 9/3/02	Supplemental IRs by all entities and Responses to Supplemental IRs
9/12/02	Final Position Statements
9/17/02	Order No. 19658 approving the KIUC transaction
10/30/02	Decision and Order No. 19755 approving amendments related to financing

Like the NextEra proposal, discovery was a continuous process that occurred throughout the proceeding. Moreover, although the PUC is not legally obligated to hold public hearings on docket items regarding changes in control, it decided to do so nonetheless, in part due to its determination that this was an issue that substantially affected the public interest.

Box 7. The Procedure for the NextEra-HECO Acquisition

In contrast, the HECO-NextEra Merger was encompassed many more discrete steps, with the PUC breaking each of the key phases of the proceeding into distinct processes. There were a significantly greater number of Orders from the PUC outlining next steps and more intervention by interested parties. In the end, the PUC rejected the NextEra-HECO acquisition.

Dates	Actions
1/29/15	Application filed by HECO and NextEra
3/2/15	Commission issues Order No. 32695, initiating the instant proceeding, establishing standards of review, an initial statement of issues and initial procedures
3/19/15	Commission issues Order No. 32726, which governs the classification, acquisition, and use of trade secrets, and other confidential information
4/1/15	Commission also issues Order No. 32739, "Establishing Issues and Initial Procedural Schedule, and Addressing Related Matters."
4/13/15	Deadline for the Direct Testimony of Applicants
7/20/15	Deadline for Answer and Direct Testimony of Intervenors
8/4/15	Commission issues Order No. 33041, "Establishing Formal Evidentiary Hearing Dates and Location, Dates for Certain Procedural Matters, and Public Listening Session Dates and Locations."
8/10/15	Deadline for answering and testimonies for the Consumer Advocate
8/31/15	Deadline for Responsive Testimony by Applicants Limited to Responding To Answering and Direct Testimony by Intervenors and Consumer Advocate
9/11/15	Commission issues Order No. 33116, "Establishing dates for additional pre-filed testimony and modifying certain procedural dates," which set forth additions and modifications to the current procedural schedule
9/30/15	Deadline for discovery
10/7/15	Deadline for rebuttal testimony from consumer advocate and intervenors
10/20/15	Deadline for all procedural motions
10/30/15	Commission issues Order No. 33296, "Addressing the four procedural motions filed on October 20, 2015"
11/6/15 11/16/2015	Parties filed their final lists of pre-filed testimony and exhibits with the commission
11/30 12/16	Formal evidentiary hearing dates
1/4/16	Commission issues Order No. 33429, which established further procedures, in addition to other steps
1/13/2016-1/29/16	Deadlines for the consumer advocate and intervening parties to issue IRs to applicants and DOD regarding the new and modified commitments, responses and rebuttals
2/1/16 3/1/2016	Evidentiary hearings
3/7/16	Commissions issues Order No. 33570, outlining the deadline dates and procedures to govern the post-evidentiary phase
3/31/16	Deadline for post-evidentiary briefs
7/15/2016	Decision and Order, "Dismissing application without Prejudice and Closing Docket."

Source: NextEra-HECO Merger Docket No. 2015-022.

4.5.3.2 Legal Considerations for Fitness, Willingness, and Ability

The standards or rationale that the PUC will institute in determining fitness, willingness, and ability will not necessarily be exactly aligned across docket cases; it is probable that some of the same issues will arise in future acquisition docket cases. For this reason, our analysis draws on the PUC decision in the 2002 KIUC acquisition of KE to extrapolate the factors that led the PUC to determine that KIUC was "fit, willing, and able" to undertake the role of a utility previously served by Citizens Communications. It then compares it to the more recent approach of the 2015

NextEra proposed merger with the HECO Companies. The rationale underling the PUC's decision to approve the KIUC merger included the following:[126]

- **Financial fitness**: According to the final decision and order, KIUC exhibited financial fitness through its projected debt service coverage ratios, equity buildup, and free cash flow balances based on RUS loan financing and rates.[127] This assessment was supported by the Consumer Advocate and the Department of the Navy, with the Consumer Advocate noting that the assumptions and methodologies exhibited conservatism.[128]

  Financial fitness was further illustrated by $25 million and $60 million proposed secured lines of credit from the CFC for working capital and for emergency purposes in the events of natural disasters, respectively. [129]

- **Willingness**: According to the final decision and order, KIUC exhibited willingness through its extensive renegotiations with Citizens to amend the original agreement and address concerns raised by the PUC, the Consumer Advocate, the County, and the Department of the Navy.[130] KIUC illustrated further willingness through the hiring of consultants and experts and its financing commitments, field audits, and investigations of all pertinent details.[131]

- **Ability:** The Consumer Advocate in the case of KIUC articulated several additional standards in addition to financial resources to judge the "ability" of KIUC to undertake the role of the utility.[132] According to the Consumer Advocate, KIUC should demonstrate that it could: 1) provide the technical expertise to maintain and operate the utility, 2) successfully transition from KE in support systems and service providers, and 3) have the necessary plant facilities to produce and deliver electricity.[133]

  To fulfill these standards, KIUC offered a transition plan for existing workers with equivalent positions and same compensation level and entered into employment agreements with the members of the management team. KIUC also committed to

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[126] KIUC D&O at 16-30.

[127] KIUC D&O at 16.

[128] *Id.*

[129] *Id.*

[130] *Id.* at 16-17.

[131] *Id.* at 17

[132] *Id.*

[133] *Id.*

becoming a member of NRECA and utilize the resources of other Cooperatives to provide high quality electrical service.[134]

In contrast, in the NextEra decision, the PUC adopted a more structured approach for determining "fitness, willingness and ability." One notable change is that in the NextEra decision, "fitness, willingness, and ability," was followed by "to properly provide safe, adequate, reliable electric service at the lowest reasonable cost in both the short and long term,"[135] whereas in the KIUC case, it was followed by "to perform the services currently offered by the utility to be acquired."[136] After evaluating NextEra according to this structured approach, the PUC concluded that the Applicants have demonstrated that NextEra is fit, willing, and able to fulfill the responsibilities of the HECO Companies.[137] These four standards were:

- Whether the proposed transaction would result in more affordable electric rates;
- Whether the transaction would result in an improvement in service and reliability for the customers of the HECO Companies;
- Whether the transaction would improve management and performance;
- Whether the transaction would improve the financial soundness of the HECO Companies.[138]

There are no changes necessary to this legal framework to accommodate new co-ops; it is plausible that any new co-op could potentially utilize the same approach that KIUC took to achieve PUC approval, achieving and applying the factors outlined in the KIUC decision to the four standards outlined in the NextEra decision. That said, the standards may differ in evaluation given the 100% renewables target by 2045 that has arisen since the KIUC acquisition. In this sense, financial fitness, willingness, and ability will likely need to be framed not simply in the ability to provide safe and reliable energy services, but also in the context of achieving the State's long-term energy goals.

4.5.3.3 Legal Considerations for Reasonableness and the Public Interest

Like the "fitness, willingness, and ability" test, this legal analysis will now extrapolate some of the reasoning for the PUC's determination that the transaction was reasonable and in the public interest. The positive conclusions, supported not only by the Applicants, but also the Consumer Advocate and the Department of the Navy, concluded that the amended agreement, the use of

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[134] *Id.* at 18.

[135] Order No. 33795 at 249.

[136] KIUC D&O at 6.

[137] Order No. 33795 at 254.

[138] *Id.* at 249-254.

KE's current rates, the acquisition of assets, and the transfer of the franchise were all reasonable and in the public interest. They concluded this based on the following reasons:

- A reasonable purchase price was supported through arms-length and fair negotiations;
- There was no stated intention to seek a rate increase now or in the foreseeable future by KIUC;
- KIUC agreed to propose and recommend RUS approval for the payment of patronage capital funds to its members in an amount equal to 25% of the previous year's margin amount;
- Citizens agreed to provide a one-time payment to KE's customers of a total amount of $3 million;
- KIUC had the ability to call upon NRECA for support;
- KIUC was eligible for applying for FEMA grants and reimbursements for up to 75% of the cost of recovery;
- The benefits of community participation in the determination of utility policy;
- Income tax exemption and financial savings from recapitalization with low-cost RUS debt;
- KE's rates were previously determined to be just and reasonable and KIUC would continue to use those rates.[139]

In contrast, during the NextEra merger, the PUC outlined a much more structured approach for determining the reasonableness and public interest of the proposed transaction. In general, and in contrast to the KIUC decision, there was much more disagreement amongst several of the key parties, most notably the Consumer Advocate and the various Intervenors versus the Applicants. The PUC agreed in many of its determinations with those opposed to the proposed NextEra transaction, concluding that the applicants had not shown the transaction to be reasonable or in the public interest.[140] To reach this decision, the PUC specifically adopted eight standards for the "reasonableness" and "public interest" standard that encompassed:

- Whether approval of the transaction would be in the best interest of the State's economy and the communities served by the HECO Companies;
- Whether the transaction provides quantifiable benefits to ratepayers in both the short and long-term;

[139] KIUC D&O at 19-20.

[140] *Id.* at 19.

- Whether the transaction will impact the ability to provide safe, adequate, and reliable service at reasonable cost;

- Whether the proposed financing and corporate restructuring is reasonable;

- Whether adequate safeguards exist to prevent cross subsidization of affiliates and to ensure the ability to audit the books and records of the HECO companies;

- Whether the transaction will detrimentally impact or enhance the State's clean energy goals;

- Whether the transaction would diminish competition in Hawaii's energy markets and what regulatory measures are required to mitigate such impacts;

Some of these standards clearly bear more relevance to the context of IOUs rather than co-ops (i.e. cross subsidization of affiliates), but the structure generally indicates the lines of thought that framed the PUC's internal debate and dialogue on the future of Hawaii's electricity system. Whether co-ops will be better served to meet these goals is not certain, but it is plausible that the benefits outlined in the KIUC case could be theoretically applied to address some of the standards mentioned in the NextEra decision.

Finally, in Appendix A of the NextEra Decision and Order, the PUC provided guidance for any future proceedings regarding mergers or acquisitions of the HECO Companies, which clearly mirrors some of the decision-making rationale that emerged in the NextEra decision itself. While the PUC is not legally beholden to judging future mergers and acquisitions according to the Appendix (the PUC specifically notes that the Appendix does not preclude consideration of other topics and areas),[141] it nonetheless provides insight into the key issues, concerns, and debates that will likely arise in future mergers and acquisitions proceedings regarding the HECO Companies. That noted, much of the Appendix A seems to be written with an intended audience of another interested IOU. However, this intended audience does not imply that prospective co-ops are free from the obligations contained therein. A description of the guidance is summarized in Box 8.

Box 8. Appendix A Guidance on Future Ownership of the HECO Companies

In Appendix A of the NextEra Decision and Order, the PUC provided guidance for future merger or acquisitions proceedings.[142] This Appendix provided guidance on the six key areas of debate in the NextEra proceeding. This encompassed the following topics:

- **Ratepayer benefits**: Ratepayer benefits must be meaningful, certain, and direct in the short-term, and insulate customers from transaction costs. It should provide benefits that are commensurate with the risks of the transaction. Mentioned potential benefits

[141] *Id.* at 1-2.

[142] Appendix A of Order No. 33795 ("Appendix A")

include rate reductions, rate freezes, grid improvements, safety and reliability, etc. Rate increases should be limited and contingent to particularly scenarios.[143]

- **Mitigation of risks**: Ring fencing measures should protect the HECO companies from bankruptcy of the corporate family.[144] This is likely less relevant in the case of a co-op acquisition and is more directly relevant in the case of another IOU proposed merger or acquisition of the HECO Companies.

- **Achievement of the State's clean energy goals**: There should be clear, short-term commitments to clean energy transformation, and clarity on a long-term vision of clean energy transformation and a competitive and sustainable distributed energy resource (DER) market.[145] Customer choice is particularly important, especially when it is more cost effective than traditional grid investments.[146] Transparency in system planning, as well as support for demonstration projects are also highly valued.[147]

- **Competition**: This standard includes a willingness to promote competitive bidding and employing best practices for bidding and procurement to ensure customer value.[148] It also includes protecting confidential and proprietary information and clarifying the role of oversight for competitive bidding.[149]

- **Corporate Governance:** The corporate governance structure should clearly reflect local governance and Hawaii stakeholders. [150]

- **Transformation of the HECO Companies:** Applicants should provide specific commitments to transforming the HECO companies into becoming customer focused, cost efficient and performance driven. It should provide measures for tracking performance in implementing these commitments, as well as staffing and programmatic needs.

Source: Order No. 33795 Appendix A

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[143] Appendix A at 2-3.

[144] *Id*. at 3.

[145] *Id*. at 9-11.

[146] *Id*. at 9.

[147] *Id*. at 11.

[148] *Id.* at 12.

[149] *Id.*

[150] *Id.* at 14.

4.5.3.4 Conclusions on Regulatory Approval

Generally, there is little reason to believe that a co-op created today would be unable to develop the supporting rationale supporting the approval of KIUC in its proposed acquisition in 2002. However, the standards for approval have changed substantially; the PUC in the NextEra docket exhibited a much more structured approach towards evaluating the desirability of mergers and acquisitions activities of electric utilities and provided substantial guidance through Appendix A of the Decision and Order on the future ownership of HECO Companies. State clean energy goals established since 2002 are also much more ambitious and frame the approach of the proceeding. That said, historical processes and documents are not necessarily a guarantee of how the PUC will choose to evaluate subsequent cases. But if Appendix A is to be any guide, co-ops would do well to execute the previously described steps with appropriate due diligence and care, with a substantial focus on how to achieve the State Energy Goals.

4.5.4 Regulatory Oversight of Cooperative Utilities in Hawaii

Generally, Cooperative utilities are subject to less regulation than IOUs in Hawaii, which may affect their overall risk and decision-making (for more details, see the final chapter on risk evaluation). This differentiation of regulatory approach by ownership structure is not unusual. Co-ops in mainland U.S. states are often, but not always largely exempt from PUC oversight, with no regulatory oversight of retail rate-setting or other matters (though this is not always the case and specific practices vary from state to state). Under Hawaii law, an entity that provides utility services to its own members and managed by its own members would not be subject to PUC regulation because such an entity is providing services to itself and not to the general public, and further, the members have general control over the entity that provides services to them.[151] Such an entity is not a "public utility" that may be regulated by the PUC.[152]

Despite this legal principle, KIUC continues to be overseen by the PUC, like the HECO Companies and unlike most cases of co-ops on the mainland. Due to concerns of what may occur if KIUC was not to be regulated at its inception, KIUC agreed not to seek regulatory exemptions from the PUC or support legislation deregulating its services until January 2008.[153] Since then, generally, KIUC has still been regulated by the PUC, and as discussed above, the PUC has statutory authority to do so.[154] However, KIUC regulation has been relaxed in certain respects; for example, KIUC is not required to undergo the Power Supply Improvement Process or the

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[151] *In Re Puuwaawaa Waterworks, Inc.*, Decision & Order No. 22200, filed in Dkt No. 2005-0137, on Dec. 29, 2005, at 14-17.

[152] *Id.*

[153] Stipulation in Lieu of Preliminary Position Statements, filed in Dkt No 2002-0060, on July 18, 2002 at 30 ("KIUC will not petition the Commission nor seek or support any legislation that would have the effect of reducing or eliminating any element of existing Commission jurisdiction over KIUC through at least December 31, 2007").

[154] See, HRS § 269-31(b).

Distributed Generation Interconnection Plan, unlike the HECO Companies.[155] Further, in terms of procurement, the PUC approved the KIUC's exemption from the Competitive Bidding Framework that governs the procurement process of the HECO Companies.[156] Moreover, the PUC will often open dockets on specific items focusing solely on the HECO Companies (for a recent example, see the recent PUC docket proceeding on Grid Modernization).[157] However, KIUC is required, on occasion, to participate in certain dockets opened by the PUC. For example, KIUC was made part of the Community Based Renewable Energy Program docket[158] and required to participate in the Distributed Energy Resource docket.[159] As such, prospective co-ops in Hawaii, if the state PUC were to adopt the same approach as has been seen in its regulatory oversight of KIUC, is likely to face less regulatory constraints on their operation than an IOU. This analysis, however, does not necessarily predict how the state Legislature or the PUC would approach the regulatory treatment of Cooperatives if they were to become a more dominant utility ownership model in the state in place of one or more of the HECO Companies.

There may be some advantages to being deemed a "public utility" under Hawaii law, such as having the power of eminent domain.[160] Thus, the newly created co-op should determine whether it desires to be regulated by the PUC as a public utility, and if so, to what extent, so it need not go through the process and uncertainty of doing so under HRS § 269-31(b). Accordingly, it may be advisable to seek legislation that would specify and clarify how and to what extent, the newly formed co-op should be regulated and considered a "public utility."

4.5.5 Conclusion on Legal Feasibility

As plainly illustrated by the presence of KIUC in Hawaii, the Cooperative is currently a legally feasible utility ownership model in Hawaii and no additional regulatory changes are necessary to accommodate co-op development. Instead, co-ops bear the burden of proof to demonstrate that they sufficiently performed their due diligence and preparation in establishment (in terms of achieving nonprofit status, following tax law and state regulations that define Cooperatives) and subsequent planning to meet the standards outlined by the PUC for transferring, owning, and

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[155] KIUC's Final Statement of Position, filed in Dkt No. 2014-0192, on June 29, 2015 at n.1 at 2; *See* Order No. 32269, filed in Dkt No. 2014-0192, on August 21, 2014, at n. 8 at 6. *See also* Order No. 32257, filed in Dkt No. 2014-0183 on August 7, 2014 at 1.

[156] Order No. 23298 Instituting a Proceeding to Investigate Competitive Bidding for New Generating Capacity in Hawaii, filed in Dkt No 2003-0372, on March 14, 2007.

[157] *See* Dkt No. 2017-0226.

[158] *See* Order No. 33268, filed as a Letter Notice, on October 21, 2015 at 1; *See* Order No. 32269, filed in Dkt No. 2014-0192, on August 21, 2014 at 1; *See* Order No. 33747, filed in Dkt No. 2015-0382, on June 7, 2015; *See also* KIUC's Comments to the Proposed Statewide CBRE Program, filed in Dkt No. 2015-0389, on March 1, 2017.

[159] *See* Order No. 32269, filed in Dkt No. 2014-0192, on August 21, 2014 at 1.

[160] HRS § 101-4

operating utility assets. The steps outlined above are all essential in this respect, particularly during the regulatory proceedings.

However, there are legal or regulatory steps that could be helpful to ensure the viability of a Cooperative. For example, co-ops seeking to serve nonrural communities that are currently served by an IOU, particularly in urban environments of Maui, Oahu, and the Big Island, may face greater challenges in raising the capital to purchase and transfer ownership of utility assets from traditional lenders such as RUS. In this case, policymakers could possibly seek means for reducing this burden, such as drawing on the preexisting legislative authority of HRS § 39A-191to further provide special purpose revenue bond support to aspiring co-ops. Additional regulatory measures could be crafted to help reduce the risks of utility ownership, thus lowering the cost of capital for such endeavors.

As discussed above, it may be advisable to seek legislation that would specify and clarify how and to what extent, the newly formed co-op should be regulated by the PUC as a "public utility."

Finally, prospective co-ops should be aware that prior mergers and acquisitions proceedings do not constitute legal precedent. Regardless, such co-ops should draw on the guidance of the PUC provided in the Appendix of the NextEra Decision and Order to make their case for approval. There is not a de facto reason why a co-op would be unable to meet the standards outlined; some of the standards likely bear little relevance to the case of the co-op, and in some cases, the co-op outperforms, such as reflecting local community stakeholder input. Additional risks that may bear implications on these standards, including possible mitigation measures, are more thoroughly outlined in Task 1.3.3. That said, the list of standards in this Appendix is not likely to be exhaustive, and additional concerns may arise.

5 Single Buyer

In addition to the co-op model, another potential option for achieving the State's energy goals is to establish a single buyer entity. The single buyer entity would be responsible for overseeing the addition of all new generation capacity through its procurement and generation planning processes, and distribution and transmission planning would remain the responsibility of the incumbent utility. This approach is not entirely without precedent: The Framework for Competitive Bidding[161] for procuring energy from independent power producers ("IPPs") and Public Utility Regulatory Policies Act ("PURPA")[162] requirements currently authorize the HECO Companies to act as a form of single buyer in select cases of energy procurement. However, the HECO Companies currently pass all charges from procured power directly to ratepayers through their respective Purchased Power Adjustment Clauses ("PPAC"),[163] suggesting that the HECO

[161] Docket No. 03-0372, Decision and Order No. 23121, Issued Dec. 8, 2006, Ex. A ("Framework for Competitive Bidding").

[162] See 16 U.S.C. §§ 2601, et seq.

[163] See, e.g., Tariff Applicable to Electric Service of Hawaiian Electric Company, Inc., Purchased Power Adjustment Clause, Revised Sheet Nos. 94-94B.

Companies may have little financial incentive to seek low prices from such projects, and may not be sufficiently "ring-fenced" as discussed below. Moreover, some IPPs have voiced concerns that this process, led by the HECO Companies, is slow and exhibits bias in favor of the generation assets of the HECO Companies.[164]

Another relevant precedent is the Public Benefits Fee initiative embodied in HRS Chapter 269, Part VII, in which a third-party administrator (now known as "Hawaii Energy") uses moneys collected by electric utilities from its ratepayers to fund demand-side management and energy efficiency programs, a function that had been previously undertaken by the HECO Companies.[165]

The PUC found that it is advantageous to use a non-utility entity to administer energy efficiency programs:

> *In the commission's view, the Non-Utility Market Structure for administering Energy Efficiency programs is the most appropriate for the HECO Companies. First, the Non-Utility Market Structure will remove the perceived inherent conflict between a utility's desire to generate revenues and income, and Energy Efficiency measures that serve to decrease sales and defer the need for additional plant investment, as discussed by the Consumer Advocate, DoD and HREA. Second, the commission expects that DSM program administration by a new entity will facilitate the introduction of innovative Energy Efficiency programs to the State, resulting in greater customer choice, increased participation levels, and higher overall energy savings. In particular, the Non-Utility Market Structure is expected to result in improved penetration in hard-to-reach and under-served segments. Third, the Non-Utility Market Structure is expected to improve the cost-effectiveness of administering DSM programs. Significantly, all the Parties and Participants either support or do not oppose at least some participation by a third-party administrator to provide Energy Efficiency programs to the HECO Companies' customers.*[166]

To address the challenges associated with the HECO Companies acting as a form of single buyer discussed above, the following analysis considers two variants of the single buyer model: one "inside" the utility, with greater ring-fencing measures (as distinguished from the status quo), and one "outside" the utility through management that is not under the HECO Companies. The single buyer would be responsible for procurement and long-term system planning and would not be responsible for system operation, including dispatch. System operation, in either version of the single buyer, remains the responsibility of the incumbent utility.

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[164] For example, see the comments from IPPs cited in Docket No. 2017-0352, Order No. 35224, "Providing Guidance on the Hawaiian Electric Companies' Proposed Requests for Proposals for Dispatchable and Renewable Generation," issued Jan. 12, 2018, at 10, 19.

[165] See, HRS §§ 269-121 through 125.

[166] Decision and Order No. 23258, Docket 2005-0069, issued February 13, 2007, at 35-36.

In both cases, the goal of the single buyer's formation would be to realign incentives in favor of the consumers' interests and to reduce or eliminate the utilities' bias towards their own generation assets. Such an independent and nonprofit single buyer entity would presumably be less subject to influence from the generation business entity. This independence would be achieved through functional separation, which entails establishing a distinct legal entity with separate accounts, operations, and management.

Historically, the single buyer model often has served as an intermediary step towards restructuring of the electric power sector.[167] The intent of policymakers in these restructuring efforts – to encourage competition and reduce rates paid by consumers – has aligned closely with the goals of the single buyer model. Thus, some of the steps may bear a likeness to the steps towards broader electricity restructuring, insofar as they strive to achieve similar objectives and thus deal with overlapping regulatory items. However, the single buyer model and restructuring should not be conflated; it is possible for the utility to remain "bundled" with legacy generation assets while new generation is procured through the single buyer approach. This analysis assumes that legacy generation assets continue to be "bundled" with the incumbent utility ownership, while all new generation assets are procured through the single buyer.

5.1 Costs of the Single Buyer Model

In contrast to the co-op model, in which the co-op would undertake all the responsibilities of the utility[168] including ownership over all its assets, the single buyer described in the following sections would only undertake the specific functions of procurement and system planning. This difference in relative responsibility suggests that the single buyer model would likely bear less up-front establishment costs to the public than the co-op approach.

Because of the difference in relative responsibilities, this section analyzes costs differently than the approach in the co-op section. Whereas in the co-op model, the analysis sought a valuation approach of the HECO Companies for the acquisition cost, as well as any transition costs, since those were the additional costs borne by the public, the following approach will seek to understand the costs of establishing an entity that is able to undertake the functions of system planning and procurement which are the core responsibilities of the single buyer. In doing so, this analysis will provide a preliminary and high-level "ball park" estimate of the ongoing costs of those functions, which the Project Team refers to as the "Year One" cost of the single buyer model. However, this analysis of costs will be further supplemented in Task 1.4.2 on the economic evaluation of the ownership and operation of each ownership model, Task 1.6.2 on how each

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[167] Arizu, Beatriz et al, "Centralized Purchasing Arrangement: International Practices and Lessons Learned on Variations to the Single Buyer Model," March 2005, The World Bank, Energy and Mining Discussion Paper No. 16, p.6, available at: http://documents.worldbank.org/curated/en/605451468154171193/pdf/374780Centralized0purchasing01PUBLIC1.pdf.

[168] Some of the major responsibilities of the utility include providing an adequate and reliability electricity supply, avoiding interruptions of service, and meeting quality of service standards as outlined by the Hawaii PUC.

ownership model would affect cash flows, and Task 1.6.3 on revenue requirements under each ownership model.

Finally, this analysis caveats the following analysis; in seeking to determine an estimate, much depends on the relative capabilities of the single buyer, which historically have transformed over time. Governments have established single buyers with differing aims and intentions, which suggests that data from these prior case examples may not reflect potential costs of the single buyer in Hawaii. For example, other single buyer models are not necessarily "true" single buyer models in that they still allow for bilateral PPAs. Single buyer models also differ in the extent of which they undertake financial risk; some single buyer models also undertake various responsibilities for managing the electricity grid system, including management of dispatch or the coordination of specific markets for other products, such as ancillary services. Therefore, readers should view the following numbers with a grain of salt. The responsibilities of the single buyer and accompanying regulation, which will be discussed in future Tasks, will clearly affect the overall cost of the single buyer. In this respect, the Project Team utilizes the costs of the now-defunct Ontario Power Authority (OPA) as the primary basis for understanding potential Year One costs, since OPA's responsibilities most closely align with the version of the single buyer that the Project Team envisions in this section.

5.1.1 Estimating the Cost of the Single Buyer Model

In general, the costs of the single buyer model are more uncertain than the co-op model. This uncertainly lies in the lack of available data for similar single buyer models in contexts comparable to Hawaii (in terms of economic development, location within the United States, island geography, envisioned single buyer responsibilities, and long-term procurement needs). As previously noted, the closest analogue to the single buyer in Hawaii as envisioned in this analysis is the now-defunct OPA in Ontario, Canada.

The 2005 annual report of the OPA provides financial statements that shed light on an approximate estimate of the establishment cost of the single buyer model, since it is the first annual report following the establishment of the OPA in 2004. [169] This report provides a breakdown of specific categories – such as capital costs, general operating costs, and personnel costs – that would be applicable to the case of a single buyer model in Hawaii. The figures are presented below, with all costs converted to 2017 USD$.[170] Note that some categories were excluded, which were unique to the OPA; this includes a Conservation Fund expense, and payments to the Ministry of Energy in Ontario to cover the costs of a prior request for proposals (RFP) undertaken by the Ministry, among others. Moreover, the OPA did not pay rent on its lease until May 2006, which may not be applicable in the case of a Hawaii single buyer. The Project

[169] Ontario Power Auth., Ensuring Ontario's Electricity Future: 2005 Annual Report, Mar. 31, 2006, available at http://cms.powerauthority.on.ca/sites/default/files/news/1713_2005_Annual_Report.pdf.

[170] To convert to 2017 USD, the Project Team converted CAD$ to USD$ at the December 2005 CAD-USD exchange rate, and then inflated December 2005 USD$ to December 2017 USD$ through the CPI Inflation Calculator available at the Bureau of Labor Statistics of the United States Department of Labor.

Team has filtered out these categories to focus on costs that would be applicable to a single buyer in Hawaii.

In its first year of operation, approximately 20% of funding (excluding the categories mentioned above) bought necessary assets of the single buyer (in the form of furniture, equipment, computer hardware and software, telephone systems, etc.), while the remaining 80% supported operating costs throughout the year.

This total cost for a "Year One" single buyer is likely to be overly high for the case of Hawaii. This is because the anticipated capacity additions to Hawaii are substantially less than the additions envisioned for OPA at the time of its inception in 2005. According to the 2005 annual report, the OPA's Supply Mix Board noted that over the next 20 years, Ontario needs to "conserve, replace or rebuild some 25,000 MW of electricity generation capacity," which fell under the mandate of the OPA.[171] In contrast, the HECO Companies envision that in the period from 2020 to 2040, they will add approximately 2805 MW of capacity, which is an order of magnitude less than Ontario's energy needs (See Figure 22).[172]

Figure 21. 2005 Up-Front Capital Costs and Operating Costs of the OPA

	Category	Cost (CAD $2005)	Cost (USD $2017)
Up-front Capital Costs	Furniture and equipment	$ 1,174,275	$ 1,718,093
	Leasehold improvements	$ 1,458,998	$ 2,134,674
	Comptuer hardware and software	$ 693,839	$ 1,015,163
	Audio visual equipment	$ 135,843	$ 198,753
	Telephone system	$ 49,217	$ 72,010
Total Up-front Capital Costs		**$ 3,512,172**	**$ 5,138,694**
General Operating Costs	General program costs	$ 536,662	$ 785,195
	Information technology	$ 101,175	$ 148,030
	Premises	$ 551,474	$ 806,867
	Office and administration	$ 494,483	$ 723,483
	Bank interest	$ 15,287	$ 22,367
	Personnel Costs		
	Staff and board costs	$ 5,929,823	$ 8,675,983
	Professional and consulting fees	$ 6,274,558	$ 9,180,368
Total Operating Costs		**$ 13,903,462**	**$ 20,342,293**
Total		**$ 17,415,634**	**$ 25,480,987**

[171] Ontario Power Authority, "Ensuring Ontario's Electricity Future," *Review of Operations,* 2005 Annual Report, available at: http://cms.powerauthority.on.ca/sites/default/files/news/1713_2005_Annual_Report.pdf.

[172] For a comparable timeframe, the Project Team uses the period over approximately the next 20 years from 2020 (when an anticipated single buyer could approximately begin operation) to 2040. These figures are drawn from the revised December 2016 PSIP submitted by the HECO Companies. It is possible that such numbers could change; previous versions of the PSIP had included various scenarios with different scenarios of natural gas use, etc.

Source: Ontario Power Authority, "Ensuring Ontario's Electricity Future," 2005 Annual Report, March 31, 2006, available at: http://cms.powerauthority.on.ca/sites/default/files/news/1713_2005_Annual_Report.pdf.

Scaling OPA's Year One costs by the relative capacity needs of Ontario and Hawaii would provide an estimated Year One funding need of $2.9 million. Of this amount, $0.6 million would be up-front capital and the remaining $2.3 million would finance ongoing. While this method is very rough, and ignores that some single buyer cost categories may be fixed rather than varying with size or complexity, the resulting budget estimate is reasonable in the context of the funding needs of the Hawaii PUC. For FY2017, the expenditures of the Hawaii PUC totaled $6.3 million; the single buyer, according this calculation, would have an ongoing budget of approximately one-third of the Hawaii PUC budget.[173]

Figure 22. Planned Capacity Expansions for the HECO Companies (2020-2040)

[173] State of Hawaii Public Utilities Commission, "Annual Report for Fiscal Year 2017," December 2017, available at: https://puc.hawaii.gov/wp-content/uploads/2017/12/PUC-Annual-Report-FY2017.pdf

Time Period	Resource Type	Capacity (MW)
2020-2025	Wind	149
	Grid Scale PV	580
	Batteries	179
	Geothermal	20
	CC	151
	Other	192
2026-2030	Wind	20
	Grid Scale PV	160
	Batteries	0
	Geothermal	60
	CC	302
	Other	20
2031-2035	Wind	0
	Grid Scale PV	100
	Batteries	0
	Geothermal	0
	CC	302
	Other	0
2036-2040	Wind	400
	Grid Scale PV	100
	Batteries	30
	Geothermal	0
	CC	0
	Other	40
Total		2805

Source: Hawaii Electric Industries, "Power Supply Improvement Plan Update Report," December 2016, Report 1 of 4, Utilized the "100% Renewable by 2030 Plan" For Molokai and Lanai, and the Revised December PSIP plan for Maui, Hawaii, Oahu. Available at: https://www.hawaiianelectric.com/Documents/about_us/our_vision/dkt_2014_0183_20161223_companies_PSIP_update_report_1_of_4.pdf

Nonetheless, there are many reasons to suspect that this cost may not be accurate, with most reasons suggesting that this may be a low estimate. First, the $.6 million would not include any costs of leasing, as the OPA secured a rent-free period until May 2006. Second, the costs of equipment, technology, and other capital, may be more expensive, as generally prices in Hawaii tend to be higher than those on the mainland.[174] On the other hand, the costs of information

[174] See the "affordability" and "cost of living index," US News, available at: https://www.usnews.com/news/best-states/rankings/opportunity/affordability.

technology, computers, and audio/visual items have declined over time since 2005.[175] Third, the analysis assumes that the costs will scale in a linear fashion; it is possible that some costs, such as personnel costs, will not scale in such a manner. For example, a certain number of key personnel with expertise will likely be necessary in any scenario, and costs might not scale further downwards even as the total amount of MW procured drops. Another possibility is that while OPA had a larger total MW procurement target, that they may have had less projects, or projects with less intensive procurement and planning requirements, than those envisioned in Hawaii.

This provides a cursory insight into the potential costs of the single buyer entity; an initial comparison with the OPA suggests that the budget of the Hawaii single buyer should be less, but comparable with the Hawaii PUC. As previously noted, a more thorough analysis of these costs will be included in Tasks 1.4.2 and 1.6.2.

Finally, with all other factors held equal, the inside and the outside single buyer models should bear relatively equal costs for the public. There are, however, several factors that may cause a difference in costs in the two models, such as the added costs of forming a new outside single buyer (compared to the costs of ringfencing current utility operations). Another factor is the additional costs of hiring more people under the single buyer model that is outside of entity. Since this single buyer model would not have any shared administrative resources as the utility (such as human resources, finance and accounting, legal, etc.), it will need to develop those in its inhouse administrative staffing.

5.2 Steps Necessary to Establish Single Buyer Model

The following analysis outlines the steps necessary to establish the "inside" and the "outside" single buyer models. As such, this analysis will distinguish when certain steps as necessary to establish the "inside" model, and not the "outside" model, and vice versa. That noted, these costs and timeline described in this section only provide a hypothetical scenario of implementation that is subject to change. This uncertainty in implementation is partially a result of the potential latitude in issues that may accompany the discussion of the single buyer. For example, the single buyer could be discussed in the context of broader market reforms or state energy ambitions; as previously noted, the model has traditionally been discussed in the context of liberalization and restructuring of the electricity market. Therefore, readers should interpret the following figures with caution. The conclusion on steps and costs are illustrated in the Figures in the conclusion of this section.

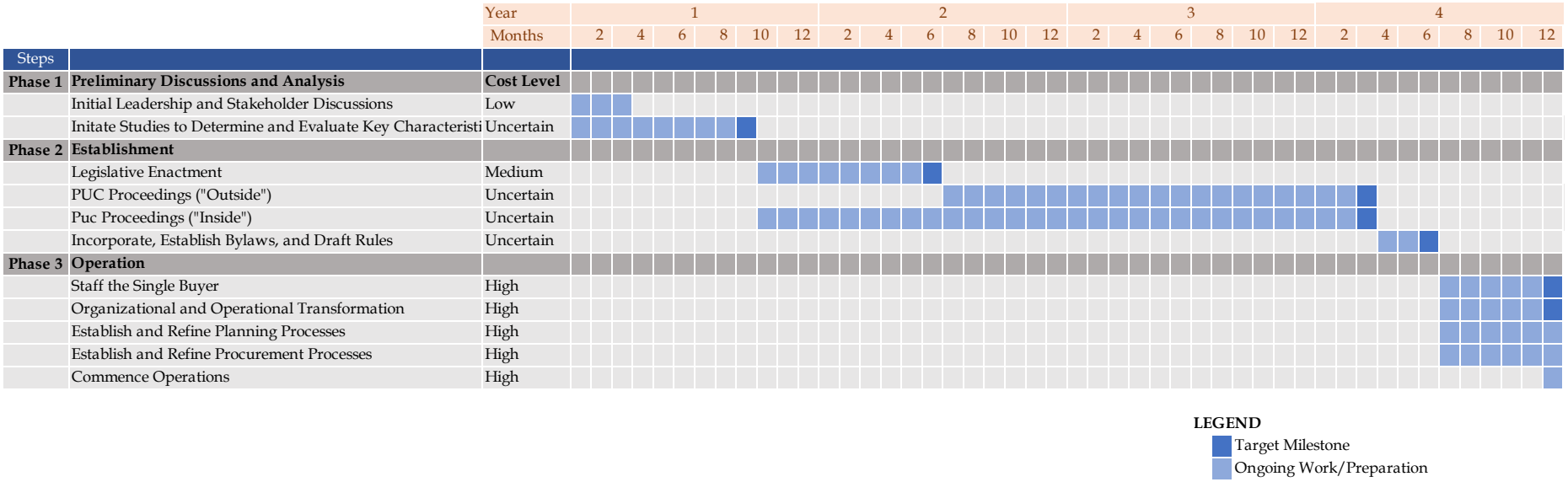
Moreover, as noted in the prior section, these steps are for a specific ideation of the "Single Buyer" model and there are significant variations on the single buyer theme worldwide. The closest analogue to the outside single buyer model outlined in the following steps is the now-defunct Ontario Power Authority, while the closest analogue to the inside single buyer model discussed in this analysis is that of the Tenaga Nasional Berhad (TNB), the only electric utility in Peninsular Malaysia. There are many other versions of the single buyer model, although many of them

[175] "Long-term price trends for computers, TVs, and related items," Bureau of Labor Statistics, October 13, 2015, available at https://www.bls.gov/opub/ted/2015/long-term-price-trends-for-computers-tvs-and-related-items.htm

undertake additional responsibilities or are not equivalent to single buyers; additional historical cases of the single buyer are present in Brazil, Egypt, Vietnam, Argentina, Chile, amongst others. Most of these examples involved the privatization of a former state-owned utility, which suggests that they may not be as clearly applicable to the Hawaii context.

Finally, the following steps assume several key factors. First, this analysis primarily assumes that the legacy utility in the case of a single buyer model is an IOU. Moreover, it assumes that the single buyer undertakes the functions of procurement and system planning, and not grid operation or dispatch. In addition, the following analysis assumes that the procurement function of the single buyer will oversee *all* new generation capacity additions.

Figure 23. Example Steps and Timeline for the Single Buyer Models



Note: This Figure provides a hypothetical four-year timeline for the single buyer model. The actual duration and costs of individual steps will be subject to the intervening factors described throughout this chapter.

5.2.1 Step 1. Initial Leadership and Stakeholder Engagement

Projected Cost: Low (<$10,000)
Projected Timeline: approx. 3 months (may overlap with Step 2)

The first step in the formation of the single buyer model is to develop a working group that will lead an initial discussion on the prospect of a single buyer model. This working group, or "Task Force" can be created through the initiative of the local citizenry, through an initiative of the Governor, through a legislative directive, or an initiative, such as through an investigative proceeding of the PUC. In any of these scenarios, sustained engagement by the local citizenry is essential for drawing attention and sustaining momentum on the establishment of the single buyer, and government creation can lend the working group greater legitimacy. In this early stage, the goals of the working group should be:

- clearly defining the problem that a single buyer is meant to solve;
- educating consumers and engage utilities on the key issues involved in energy procurement and planning and their implications;
- outlining the role and purpose of a single buyer, including prospective benefits and drawbacks; and
- evaluating the single buyer approach against other potential approaches.

Ideally, this leadership and stakeholder engagement should occur on all affected islands, include a diverse range of perspectives from all cross-sections of society, and solicit input from those with expertise in energy systems operation and management. The timeline of this stakeholder engagement is expected to be longer than required for the co-op model because of the relative unfamiliarity of the local population with the single buyer approach. While the overall cost of this step is *low* to the public, the care and rigor taken during this step will be reflected in all future steps. This is because both single buyer approaches will likely entail legislative and regulatory proceedings. Such deliberations will reflect the "buy-in" and due diligence of proponents in engaging stakeholders.

5.2.2 Step 2: Initiate Studies to Determine and Evaluate Key Characteristics of the Single Buyer

Projected Cost: Uncertain (subject to the scope of the study; honoraria and/or consulting fees; size of the expert team or panel; and travel and other logistical costs)
Projected Timeline: 9-12 months

The second step is to determine the desired single buyer model in Hawaii, as forming such an entity requires policymakers to make decisions on several key factors. Three of these key decision factors, which are discussed below, are:

- Whether a single buyer would be intended to exist in the long-term or serve as a transitory step towards achieving desired policy objectives;

- The ideal institutional design of the single buyer, i.e. whether it should operate "inside" or "outside" the utility structure and what type of entity it will be. If the single buyer is "inside" the utility, it could be a formally separate affiliate entity or a ring-fenced department or division. If the single buyer is "outside" the utility, it could be a government agency or a contracted non-profit;

- Determining if new generation assets should be developed exclusively by independent providers, or if utility "self-build" should be permitted.

The working group, or "Task Force," should meet with all stakeholders and solicit presentations from experts on these topics as a part of their study. In terms of prior research, the Project Team is analyzing numerous characteristics of the single buyer in this study and its accompanying tasks. In addition, the PUC has already provided significant guidance on the desired characteristics of the electricity grid system,[176] and there are ongoing proceedings regarding procurement of renewable generation in Docket No. 2017-0352.[177] Subsequent studies may seek to evaluate not only the single buyer, but related issues, explicit approaches towards integrating the single buyer into outcomes of the competitive procurement docket and ongoing resource planning processes, and a more deliberate and focused approach towards electricity market rules and structure.

Box 9. Stakeholder Engagement and Studies Preceding the Creation of the OPA

The establishment of the OPA in 2004 was preceded by a period of high prices from May to November 2002, during which the prices rose by an average of over 30%. In June 2003, the Government of Ontario established the Electricity Conservation and Supply Task Force (ECTSF) to develop an action plan to address Ontario's need for affordable and reliable electricity supply to 2020. During this time, the ECTSF "met thirty times and had detailed discussions with over 90 individuals and organizations representing all sectors of society."[178]

[176] For example, see the PUC Inclinations on the Future of Hawaii's Electric Utilities, April 2014, available at: https://puc.hawaii.gov/wp-content/uploads/2014/04/Commissions-Inclinations.pdf.

[177] The Commission opened this docket to "receive filings, review approval requests, and resolve disputes, if necessary, related to the [HECO Companies] requests to proceed with competitive procurement of dispatchable firm generation and new renewable energy generation on the islands of Oahu, Hawaii, Maui, Molokai, and Lanai," which corresponds to the companies PSIPs, which state the companies' plan to procure nearly 400 MW of new renewable resources across their service territories by 2021. Order No. 34856 Opening the Docket, Docket No. 2017-0352, issued October 6, 2017. In a subsequent order, the PUC expended the number of projects that the HECO Companies could select for the Final Award Group for each respective company. Order 35529, issued June 15, 2018. In another subsequent Order, the PUC approved the Companies' proposed additional Performance Incentive Mechanism applicable to PPAs. Order No. 35664, Issued Sept. 6, 2018.

[178] 2004 Report of the ECSTF, Exhibit CDA-59, pp. 1-2.

The Task force itself consisted of "19 leaders from all parts of the electricity industry, including representatives of consumers, workers, environmental groups and the Ministry of Energy."[179]

The report provided 59 specific recommendations for the Government. Amongst its conclusions, the report stated that the province should have "less reliance on the spot market as a signal for new investment. There should, instead, be greater reliance on long term contracting between generators and large volume buyers.", which eventually led to the creation of the single buyer, the Ontario Power Authority.

Source: Treybilcock, Michael and Roy Hrab, "Electricity Restructuring In Ontario," The Energy Journal, Vol. 26, No. 1, 2005. Also see the "Report of the Panels," Canada – Certain Measures Affecting the Renewable Energy Generation Sector," 19 December 2012, WT/DS412/R, World Trade Organization for a summary of events.

5.2.2.1 Determining the Long-term Vision of the Single Buyer

One key consideration for the single buyer model is determining if it will serve as a long-term entity or if it will serve as a transitional entity towards greater competition in a fully unbundled market. Regardless of utility divestment from generation assets, it is possible and likely that IPPs will own and operate a greater share of the generation assets under a single buyer, presuming that certain provisions are in place that limit or eliminate the ability of the incumbent utility to participate in new generation procurement in an anticompetitive manner.

As previously noted, most single buyer approaches have historically served as an intermediary step towards restructured markets. In such markets, utilities are not only functionally unbundled; ownership is unbundled as well (See Box 10 for an explanation of these different types of unbundling).[180] Often, single buyer approaches have served a step towards a "many-to-many" market construct in which both wholesale and retail markets operate competitively. Clearly, in a "many-to-many" market construct, there would not be a *single* buyer, but many buyers. Whether this approach is appropriate for Hawaii, given its energy goals, will be discussed in the second scope of this project, which will evaluate potential regulatory models. Some of these regulatory reforms, such as further ownership unbundling, entail additional steps, such as determining the repayment of stranded costs, which will not be discussed in detail in this analysis.

These choices will determine the long-term institutional planning and design of the single-buyer entity. If a single buyer is intended to serve as a transitory entity towards further industry

[179] Gibson, Donald, "Ontario Electricity conservation and Supply Task Force Report Released, January 15, 2004, available at: http://www.mccarthy.ca/article_detail.aspx?id=1468

[180] Arizu, Beatriz et al, "Centralized Purchasing Arrangement: International Practices and Lessons Learned on Variations to the Single Buyer Model," March 2005, The World Bank, Energy and Mining Discussion Paper No. 16, p.6, available at: http://documents.worldbank.org/curated/en/605451468154171193/pdf/374780Centralized0purchasing01PUBLIC1.pdf

restructuring, policymakers should determine how a broader set of market rules and operations will be managed over the long term, and whether the single buyer should eventually take on the responsibilities of an independent system operator ("ISO") to manage such a market. If so, this affects the desired infrastructure, personnel, capabilities, and governance of the single buyer. It determines the costs that the single buyer may initially undertake and phase in to prepare for a more long-term transformation towards the envisioned market and regulatory design.

The single buyer cannot be separated from regulatory context. Therefore, for the purposes of the following analysis, the Project Team assumes that the utility has not been unbundled, and that the utility continues to own generation assets, and that all new procurement must occur through the single buyer entity in alignment with the planning of the single buyer, with sufficient protections to mitigate uncompetitive behavior.

Box 10. Different Forms of Unbundling

Initiatives in unbundling utility assets have spanned a range of approaches. Each of these approaches has sought to reduce or eliminate utility bias towards its own generation assets by separating overlapping interests related to generation and wires. These initiatives are taken with the goal of creating more competition in the generation sector, which theoretically entail potential decreases cost and thus lower rates for consumers. The following terms offer a useful framework for understanding efforts at unbundling in terms of their degree and definition:[181]

- **Legal Unbundling:** This form of unbundling entails the creation of a legal subsidiary for one of the utilities. It requires that transmission and generation assets operate under legally distinct entities.

- **Functional Unbundling:** Often referred to as "management unbundling," this form of unbundling separates operational and management activities for transmission and generation assets. This includes "accounting unbundling," which requires separate accounts for network activities and generation activities to protect against cross-subsidization.

- **Ownership Unbundling:** Ownership unbundling entails that separate ownership of generation and transmission assets. Such entities are not allowed to hold shares in both activities.

These approaches are not necessarily mutually exclusive. For example, an entity may be legally unbundled, but not necessarily functionally unbundled. In the case of an "inside" single buyer model, there would be accounting, functional, and legal unbundling for the procurement and system planning functions of the utility.

[181] Koten, Silvester and Andreas Ortmann, "The Unbundling Regime for Electricity Utilities in the EU: A Case of Legislative and Regulatory Capture?" CERGE-EI, May 2007, page 4 Working Paper Series, available at: http://web.worldbank.org/archive/website01021/WEB/IMAGES/2007WP32.PDF

5.2.2.2 Determining Whether to Place the Single Buyer "Inside" or "Outside" the Utility

Should policymakers choose to establish the single buyer, they will also need to determine whether to establish the single buyer "inside" or "outside" the utility. As previously described, the HECO Companies currently undertakes the responsibilities of a single buyer through the Framework for Competitive Bidding and occasionally through PURPA requirements. However, this single buyer is neither legally nor functionally unbundled from the rest of the utility; it is the utility itself, albeit with some protections for IPPs and the independence of the procurement process through Codes of Conduct. The utility also engages in its own system planning efforts through the Power Supply Improvement Plans ("PSIP") process and other initiatives under the oversight of the PUC.[182] In the case of this analysis, a reformed "inside" utility single buyer model would entail:

- further functional unbundling of procurement and system planning functions, including segregation and ring-fencing of single buyer employees and associated communications, branding, and infrastructure;
- legal unbundling of the single buyer from the utility;
- greater oversight over the procurement process and single buyer entity by the PUC;
- requiring that all new generation must be procured through the single buyer procurement process; and
- housing system planning functions within new single buyer entity, with appropriate coordination mechanisms with the incumbent utility.

The "outside" single buyer would also need to accomplish all the above requirements, with the distinction that instead of seeking "ring-fencing" (since the "outside" single buyer is already external to the incumbent utility), it should implement adequate conflict-of-interest provisions and protections.

Both approaches are subject to unique risks that bear on their steps for a formation that will be elaborated throughout this section and the following legal section. They also face unique long-term challenges beyond implementation; for example, a single buyer that is still owned by the utility may face greater difficulty in convincing stakeholders that it is procuring energy in a neutral fashion if the incumbent utility is already viewed with distrust since its duty will still be

[182] There are other activities that the HECO Companies engage in that bear on the system planning efforts and are reflected in distinct dockets. See, e.g., Docket No. 2017-0226, Decision and Order No. 35268, Issued February 7, 2018. See also the HECO Companies, Planning Hawaii's Grid for Future Generations: Integrated Grid Planning Report, March 1, 2018 available at https://www.hawaiianelectric.com/Documents/about_us/our_commitment/20180301_IGP_final_report.pdf.

to its shareholders. If either of the single buyer models hires too many employees from the incumbent utility, or if they are perceived to be too closely related to the incumbent utility, then it may undermine the perceived neutrality and legitimacy of the single buyer itself. These are only some factors that policymakers should consider when establishing the single buyer models.

5.2.2.3 Determining Whether to Allow Utility Self-Build Options

In either case of the single buyer approach, one key question is whether and how the utility should be allowed to offer a self-build option in the procurement process (meaning, whether the incumbent utility would be able to contract with the single buyer to develop generation assets, or whether only independent producers would be eligible).

The issue of self-build generation has been discussed in the proceeding for renewable generation that is currently before the Hawaii PUC, Docket No. 2017-0352.[183] In the recent comments filed, some representatives from IPPs have argued that a self-build option is inappropriate. This suggests that similar comments would likely arise in a similar discussion of procurement guidelines for the single buyer. Some have argued that insider and privileged information on the part of the utility is "inherent" in any self-build proposal, and that "even in the case where self-build projects are undertaken by organizationally separate utility affiliates, there is no mechanism that can assure against transactional abuses."[184]

Various options to address this dilemma include:

- Allowing self-build options,
- Allowing for no self-build options,
- Permitting self-build options with various safeguards and mitigation measures against anticompetitive behavior.

Some considerations for allowing self-build options are whether they would deliver public benefits by encouraging greater competition, whether allowing self-build options protects against the risk of insufficient competition or bidders and whether such participation provides a fair basis for comparison. While this analysis will not offer a definitive answer to this question, the Project Team flags this as an important consideration for the steps to establish the single buyer model because it shapes the procurement process (i.e., when can and when should self-build options be developed and revealed to bidders, and whether this would require additional protections to segregate a potential self-build team from the single buyer and other divisions of the utility) and affects the competitive environment.

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[183] See Docket No. 2017-0352, Order No. 35224, "Providing Guidance on the Hawaiian Electric Companies' Proposed Requests for Proposals for Dispatchable and Renewable Generation," Issued Jan. 12, 2018, at 10-12, 31-32.

[184] See Docket No. 2017-0352, Order No. 35224, "Providing Guidance on the Hawaiian Electric Companies' Proposed Requests for Proposals for Dispatchable and Renewable Generation," Issued Jan. 12, 2018, at 11-12.

Box 11. Managing Self-Build Options with Battery Storage

The decision to disallow the incumbent utility from participating in self-build projects can give rise to additional complex issues with respect to DER integration. For example, with regards to the case of battery storage in Texas, American Electric Power's plans to install two lithium ion battery systems as an alternative to traditional transmission and distribution (T&D) upgrades has been opposed by a coalition of energy generators, the Texas Office of Public Utility counsel, and various consumer advocacy groups. They argue that the battery storage would have negative effects on the competitive market, since it would displace market generation, suppress prices and distort scarcity price signals. The proponents argue that the energy storage would reduce charges with regards to T&D maintenance and that the effects of the facility in question on the market would be minimal. These are clearly complex issues that will continue to emerge with DER assets that can serve as both load and generation.

Source: Utility Dive, "Storage or Generation? AEP Case Could Help Answer the Question in Texas, October 24, 2017, available at: https://www.utilitydive.com/news/storage-or-generation-aep-case-could-help-answer-the-question-in-texas/507943/

5.2.3 Step 3: Legislative Enactment

Projected Cost: Medium (<$100,000, subject to many variables)[185]
Projected Timeline: 6-12 months

If the prior studies conclude that the single buyer is both appropriate and desirable with respect to the State's energy goals, the next step is for the Hawaii state legislature to enact legislation establishing the single buyer. The Hawaii state legislature can prompt action on the single buyer through a variety of means and levels of specificity, as will be further described in the subsequent legal analysis. In this respect, the "outside" single buyer model likely requires legislative enactment. Although it may be possible for the PUC to independently impose single buyer-like measures for an "inside" single buyer model that is not legally unbundled through docket consideration related to the Framework for Competitive Bidding and the Framework for

[185] There are little studies on the cost of passing legislation through the Hawaii legislature and there is not likely to be a simple answer to this question. Some of the factors in the cost of a bill involve: the level of time and effort it takes to draft a bill; whether additional studies (i.e. a determination of economic impacts) are necessary for the bill; the degree of debate over the bill. These impose staff costs throughout the process, and because there are usually multiple bills under consideration at any given moment, it is difficult to put a price tag on a single bill. As one relevant data point, the Legislative Study Office of the Wyoming State Legislature concluded in 2010 that the average cost of passing a bill is between $453 and $39.

Integrated Resource Planning[186] (or future evolved planning framework[187]), and the HECO Companies' Codes of Conduct,[188] legislative action would be useful, if not necessary from a practical standpoint to require the PUC to implementing the necessary changes to establish a single buyer model.

There are many cases in which legislative involvement is not only helpful, but necessary. One case is if the single buyer requires initial state funding, which will be discussed more extensively in the legal feasibility section. Another case is if the franchise agreements with the HECO Companies need to be amended for any variety of reasons; such reasons might include clarifying the roles and "privileges" of the utility under the single buyer model, renegotiating franchise fees, or aligning the agreement with state goals and initiatives.[189] Additionally, if a separate affiliate legal entity is created to enable the "inside" single buyer model, legislation may be necessary to ensure that the PUC has jurisdiction over the single buyer.

Beyond such requirements, the Hawaii legislature may also choose to outline the guiding principles and mandate that will 1) govern the operation of the single buyer and 2) be reflected in subsequent rulings and decision-making by the PUC and executive agencies. Some proposed core principles are outlined in Box 12.

At the discretion of the legislature, such legislation should address other essential characteristics, such as the establishment of new agencies, their endowed powers, funding, responsibilities, relationship, and oversight by other agencies (such as whether the single buyer will be under the oversight of the PUC), among other concerns. In addition to the franchise agreements, it should amend any other legislation as necessary to support the single buyer. One case example of the formation of a single buyer through legislation is provided in Box 13 in the case of the Electricity Restructuring Act of 2004, which created the OPA.

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[186] Docket No. 2009-0108, Decision and Order, Issued March 14, 2011, Ex. A ("Framework for Integrated Resource Planning").

[187] *See* Order No. 36659, Instituting a Proceeding to Investigate Integrated Grid Planning, Docket No. 2018-0165, filed on July 12, 2018.

[188] As previously noted, several IPPs have commented on the HECO Companies' Codes of Conduct for procurement in Docket No. 2017-0352 proceedings for the procurement of renewable generation resources. See Docket No. 2017-0352, Order No. 35224, "Providing Guidance on the Hawaiian Electric Companies' Proposed Requests for Proposals for Dispatchable and Renewable Generation," Issued Jan. 12, 2018. The PUC recently opened Docket No. 2018-0065 to review the HECO Companies' Codes of Conduct. See Docket No. 2018-0065, Order No. 35363, Issued Mar. 22, 2018.

[189] See the legal section on use-cases for amending the franchise agreement to support the single buyer. The franchise agreements are available in the Applicants' Response to LOL-IR-38, Docket No. 2015-022, or the regulatory proceeding for the NextEra merger. HECO's franchise appears at the Revised Laws of Hawaii of 1925, pages 1980-85, as amended by Act 134 of 1961 and Act 88 of 1974. HELCO's franchise is Act 130 of 1963. MECO's Maui franchise is Act 12 of 1991. MECO's Lanai Franchise is Act 54 of 1988. MECO's Molokai Franchise is Act 147 of 1989.

Box 12. Potential Guidance Principles for the Single Buyer

In drafting legislation related to the single buyer, the Hawaii legislature should impose measures to achieve certain guiding principles. Other single buyer agencies often draft and establish similar principles for their operation.[190] The purpose of such principles is to ensure public confidence in the single buyer (which should be perceived as a neutral agency for energy procurement and services) and to ensure the long-term sustainability of its operations. Some potential principles include:

- **Transparency:** The single buyer should be transparent about its rationale and criteria throughout the entirety of the procurement process. It can do so by clearly outlining and defining criteria by which it will select and evaluate projects and consistently communicating with the public on its ongoing initiatives, management, and operations.
- **Fairness:** The single buyer should procure projects in a manner that grants all proposals equal consideration on equal terms in the evaluation process. No project should be prioritized for reasons that undermine the public interest.
- **Independence:** The single buyer should be independent from potential influence, either by state entities or via regulatory capture by corporate interests. It should avoid potential conflicts of interest with its public-serving role. The interests of the power generation sector are of particular concern, given that they would likely be the beneficiaries of biased procurement practices.

In terms of the funding for the single buyer, the legislation should clearly outline how the single buyer entity will be financed. In the case of the "outside" single buyer model, the legislature will likely need to allow for bond financing for the initial establishment. Alternatively, the legislation could allow for ratepayer funding of the "outside" single buyer, similar to the funding established for the Public Benefits Fee used by a third-party administrator (Hawaii Energy) to administer energy efficiency programs in lieu of the utility doing as discussed above, pursuant to HRS Chapter 269, Part VII.[191] In the case of the "inside" single buyer model, the funding could be approved by the PUC through the HECO Companies. Both could include the single buyer cost as

[190] For an illustrative case for the internal single buyer model, see the "Vision and Mission" of the Ontario Power Authority, which includes the following subsections: Transparency, Accountability, Flexibility, and Collaboration.

[191] See, HRS §§ 269-121 through 125.

a specific charge on their utility bills or as a transactional cost for IPPs participating in the procurement process.

The costs of legislation are difficult to determine for a variety of reasons mentioned in Section 5.2.3, and footnote 184above. The timeframe for legislative passage is subject to significant variability, depending on the congruence of stakeholders and their interests. Therefore, the Project Team determines that the cost of this step is *medium* and suggests that a timeframe for legislative passage is approximately six to twelve months, noting that this is a tentative estimate.[192]

Box 13. The Electricity Restructuring Act of 2004 - Ontario, Canada

The Electricity Restructuring Act of 2004 created the Ontario Power Authority ("OPA"), which functionally established a single buyer model "outside" the incumbent utility. At the time, the OPA reported to the Ministry of Energy. The OPA merged with the Independent Electricity System Operator in 2015, creating one unified entity for procurement, dispatch, and system planning. The following outlines some of the key stipulations of the Electricity Restructuring Act of 2004 that informed the creation of OPA:

- The *nature* (corporation, nonprofit, etc.) and *governance* (board of directors) of the entity;
- The *objectives* of the OPA;
- The terms of *dissolution;*
- The *capacities, powers,* and *authorities* of the OPA;
- The *funding* of the OPA;
- The *independence, terms*, *election, and duties* of the board of directors;
- The nature of any *panels* (i.e., a specific panel on electricity conservation and load management);
- Any required *reporting*;
- Any required *stakeholder engagement*;
- Other related issues.

[192] For example, consider that HB 623, the bill which requires 100% dependency on renewable energy by 2045, took approximately six months from introduction in January 2015 to executive signature on June 2015.

5.2.4 Step 4: PUC Proceedings

Projected Cost: Uncertain
Projected Timeline: 1-3 years

Regardless of whether the Hawaii legislature has acted on the single buyer (which is necessary for the "outside" single buyer case, but might not be necessary for the "inside" single buyer case), both scenarios will likely require a PUC proceeding. In the case of the "inside" single buyer, the PUC could open a docket on the Framework for Competitive Bidding, and depending on whether the decision to shift to the "inside" single buyer model occurred relatively soon, could also open a PSIP docket, with the intention to reform both Frameworks to establish the stringent Codes of Conduct and other rules that would implement the functional unbundling of the utility's generation assets from their wires assets. If the shift does not occur within the very near future, the PUC is could still open a Competitive Bidding docket, but would probably open an Integrated Grid Planning docket instead of a PSIP docket, because Integrated Grid Planning will likely replace the PSIP framework (and the IRP framework) once the investigative proceeding and other implementation processes have concluded.[193]

In the case of the "outside" single buyer model, the PUC could likely open similar dockets as those described above, with a greater focus on achieving the objectives and metrics that are outlined in the legislation that established the single buyer. Both cases would likely involve the PUC establishing the processes by which the single buyer procures energy as well as determining the appropriate level of oversight and engagement of the PUC with the single buyer throughout that process.

The cost for this step is *uncertain.* Similar to the cost of legislation, estimating the cost of PUC Proceedings is unlikely to have a simple answer. The costs are subject to variables and contingencies such as the contentiousness of proceeding under consideration. The fact that the PUC oversees multiple open dockets at once makes estimating the cost of PUC Proceedings no straightforward task. For context, the PUC had operating expenditures of $6.2 million in FY 2017 and issued a total of 859 decision and orders and closed 454 dockets.[194] However, not all dockets are equivalent in time spent and complexity. Of course, this also does not include any other costs to other parties to a PUC proceeding, such as the Consumer Advocate or the utilities.

The timeline for this step, however, can be substantial and variable as proceedings at the PUC can take up to several years. For example, the previous docket proceeding on Framework for Competitive Bidding in 2006 was approximately three years from establishment of the proceeding in October 2003 to the final framework in December 2006. The 2009 proceeding on amendments to the Framework for Integrated Resource Planning (IRP) Framework took a little more than two years, from May 2008 to March 2011. The Project Team provides a range of one to

[193] Order No. 35569, Docket No. 2018-0165, issued July 12, 2018.

[194] https://puc.hawaii.gov/wp-content/uploads/2017/12/PUC-Annual-Report-FY2017.pdf

three years as an approximate estimate. Deadlines included in legislative enactments establishing a single buyer entity could help to give more certainty to these projected time frames.

5.2.5 Step 5: Incorporate, Establish Bylaws, and Draft Single Buyer Rules

Projected Cost: Uncertain
Projected Timeline: 3 months

The next step is to incorporate the single buyer entity. Generally, both single buyer models will likely and ideally be chartered as non-share, non-profit organizations to minimize any incentives for profit-taking, and thus eliminating the need for any return on equity.[195] The charters of each of the entities should reflect the priorities of the legislative acts that brought such entities into existence, including the principles outlined above. Such a charter will include the creation of the initial board of directors and define the fundamental characteristics of the single buyer.

Like the discussion of articles of bylaws in the co-op section, the single buyer will similarly have to craft bylaws by which they will govern their organization. Clearly, these rules will reflect the intended vision of the single buyer approach. Such bylaws will likely cover topics such as:

- Determining the board directors, duties, and means of appointment;
- Determining officer positions, duties, and means of appointment;
- Procedures to mitigate and resolve conflicts of interest;
- Describing the circumstances in which officers and directors cease to hold office;
- Remuneration and benefits to members of the board;
- The establishment, composition, and functions of any key panels or committees overseeing single buyer functions.[196]

Generally, the outcome of this process will be the establishment of a set of single buyer guidelines. An illustrative example is the single buyer guidelines of the Single Buyer in Malaysia.[197] While this single buyer possesses more capabilities than the single buyer considered for Hawaii in this analysis (such as dispatch and scheduling methodologies), its single buyer guidelines clearly

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[195] If there is an incentive for profit-taking, this could encourage the single buyer to procure more energy than necessary, increasing overall costs for Hawaii residents.

[196] For example, much like the OPA, the single buyer may choose to establish particular panels on procuring particular types of whether it be energy conservation, demand response, etc.

[197] "Single Buyer Rules," Version 2.0 (January 2015), available at: https://st.gov.my/index.php/.../94-guidelines-electricity.html?...548:single-buyer-rules.

outline the objectives, roles, and functions of the single buyer, ring-fencing, governance, and plans to fulfill the procurement and planning functions.

Related to the incorporation of the "outside" single buyer model, there are several options for where such an entity could be placed organizationally. One scenario is that a single buyer would be governed through the head of energy and environmental department, which in the case of Hawaii, could fall under the Hawaii State Energy Office, within DBEDT. In another case, the single buyer would be housed under the authority of the PUC. The single buyer could be contracted by the PUC, like how Hawaii Energy is contracted to administer energy efficiency programs as discussed above pursuant the HRS Chapter 269, Part VII. Another example may be found in Chapter 269, Part IX Electric Reliability, where the PUC may establish and monitor reliability standards and interconnection requirements, and may contract for the performance of these functions with a person, business or organization to serve as the "Hawaii electric reliability administrator" ("HERA") to be funded by a surcharge collected by the HECO Companies.[198]

An alternative model would have the appointees determined at a higher level by the Governor. Yet another possibility is electing the positions directly. Regardless of the approach, the determination of the board should reflect the priorities of the local population and possess the requisite expertise to make determinations on energy procurement and planning decisions.

Like the co-op model, the costs of actual incorporation are likely to be *low*; the tasks of filing the necessary paperwork for such entities is not significant. For example, the cost of incorporating a non-profit with the Department of Commerce and Consumer Affairs is only $25.00.[199] However, the task of determining the answer to key questions governing bylaws, to the extent that the legislation authorizing the single buyer has not done so, is likely to require significant discussion and deliberation, which will impose significant labor costs. That said, much of the deliberation over these documents are likely to have taken place throughout the legislative process or the PUC proceeding.

5.2.6 Step 6: Staff the Single Buyer

Projected Cost: High (>$250,000)
Projected Timeline: 6-12 months

Following its incorporation and formalization of its bylaws, the single buyer will then be tasked with staffing. The single buyer should seek to endow itself with the management capabilities and expertise required to oversee system planning and procurement efforts. The requirements for this can differ based on whether the single buyer is "outside" or "inside" the incumbent utility, although both approaches pose relative challenges. The following bullet points outline some of the key differences between the two approaches.

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[198] HRS §§ 269-141 through 149.

[199] Fees/Hawaii Business Corporation Act, Chapter 414D, available at: http://cca.hawaii.gov/breg/registration/dnc/fees/

- The "outside" single buyer will likely need to hire more employees, as some of the shared services such as human resources, legal, and finance/accounting would not be available anymore for the "outside" single buyer.

- In terms of hiring practices, if the "outside" single buyer is a public entity, the "outside" single buyer may need to adhere to a range of civil service guidelines set forth under HRS Chapters 76 and 78 as well as HAR Title 14, although there may be exemptions to such practices. The "inside" single buyer is not necessarily beholden to such restrictions. Alternatively, it is possible that if the "outside" single buyer operates as a non-profit, it also would not be as restricted by such restrictions.

- In the case of the "inside" single buyer entity, the staffing of the single buyer should be clearly distinct from the rest of the utility itself; this will be set in the Single Buyer guidelines, which will contain the ring-fencing mechanisms.

To staff the new single buyer entity, the utility should undergo both a needs assessment and a hiring process with rigorous safeguards for potential conflicts of interest:

- **Needs assessment:** The utility should first determine, based upon the required responsibilities, the capabilities, and capacities that they will need for the single buyer entity. At a very high level, these needs will likely encompass the departments highlighted in Box 14. Note that these required capabilities are primarily for bid evaluation; however, system planning will likely encompass similar divisions.

  Note that in the "inside" single buyer model, it is likely that some of these divisions – such as the generation planning division and the transmission planning division – be entirely under the single buyer entity.

- **Development of on-boarding processes:** In either scenario, the single buyer should develop rigorous on-boarding processes that mitigate the concerns of the single buyer in terms of confidentiality and conflict-of-interest, and promote the desired workplace norms and culture. This includes training to ensure compliance with the single buyer guidelines. Again, such on-boarding processes are likely to have differences based on whether the single buyer is "outside" the utility, or under ownership of the utility.

- **Ongoing hiring for unfilled capacity:** The single buyer will need to hire additional capacity as necessary for single buyer functionality. In the case of the inside single buyer model, this task is likely to require less hiring, given that the utility can draw on its existing workforce for unfilled capacity. Regardless, the "inside" and "outside" single buyers will both need to hire for positions with competitive compensation.

Box 14. Required Capabilities for Bid Evaluation

The evaluation of bids requires substantial in-house capabilities and expertise. Such expertise covers the scope of power systems, environmental evaluation, and legal and regulatory adherence. In the 2007 docket for "Competitive Bidding for New Generation," HECO identified the following divisions as likely to play a role in developing and evaluating RFPs:[200]

- Power Supply Engineering Department
- Power Supply Operations and Maintenance Department
- System Operations Department
- Generation Planning Division
- Transmission Planning Division
- Technology Division
- Protection Engineering Section
- Transmission Substation Engineering Section
- Environmental Department
- Lands and Rights of Way Division
- Fuels Division
- Financial Analysis Section
- Purchasing Division
- Risk Management Division
- Regulatory Affairs Division
- Legal Department

As a rule of thumb, the single buyer, as the overseer of the procurement activity, should also seek capabilities in the divisions and departments mentioned above.

In terms of the overall cost of hiring, the total and ongoing costs are likely to be *high*, given the scope of the hiring needs and expertise required. This may also require the hiring of a recruitment firm, which will impose additional costs. Moreover, the timeline for hiring is likely to be substantial, subject to labor availability and possible organizational and bureaucratic procedures unique to the "outside" and "inside" single buyer approaches. For example, in the case of the "outside" single buyer, prospective employees may be required to take a civil service exam that is not required in the case of an "inside" single buyer."

5.2.7 Step 7: Organizational and Operational Transformation

Projected Cost: High (>$250,000)
Projected Timeline: 6-12 months

[200] Docket No. 03-372, Letter from William A. Bonnet, Vice President, Gov't and Community Affairs, HECO to PUC, filed June 15, 2007.

The next task for the single buyer model is to establish the management processes and mechanisms that will guide the operation of the single buyer. This task will coincide with the hiring of personnel; ideally, the initial, high-level management hires of the single buyer should craft an organizational chart to help guide the subsequent hiring needs of the single buyer. The single buyer will need to organize into a variety of divisions with associated internal management structures. One basic potential internal structure would include the following divisions:

- Electricity Resources
- Power Systems Planning
- Finance and Administration
- Environmental Evaluation
- Regulatory and Legal Affairs
- Communications

In addition to these divisions, the single buyer may seek to establish additional programs or divisions that operationalize state initiatives or incentives in other key areas that fall outside the realm of traditional procurement but nonetheless, have to affect system planning and generation supply. This includes items such as demand response, conservation, and other behind-the-meter programs. After establishing these divisions, the single buyer should coordinate engagement mechanisms with the relevant government agencies (including the State Energy Office and the PUC) that either engages or oversees the single buyer.

In terms of its external facing nature, the "inside" single buyer ought to ensure that it has the supporting infrastructure to ensure adequate ring-fencing. This includes:

- Physical separation from all legacy utility personnel and buildings;
- Separated branding;
- Distinct communication channels and IT infrastructure;
- Separate accounting procedures and financials;
- Arrangements of third-party audit to comply with SB rules.

Finally, in addition to formally defining the structure of the single buyer, the board of directors should clearly seek to define internal workplace culture, define clear performance metrics for employees, and seek to instill the mission of the organization – as defined by the principles of the single buyer – into the activities of the single buyer.

As part of the set-up cost, the initial cost of establishing these management mechanisms are uncertain but are likely to be *high*. This is because organizing the management of the new entity

is a continuing work in progress from the establishment of the organization, likely to require significant labor hours, and possibly the hiring of a consultant. The project team estimates a likely timeframe of approximately six months to one year; it should be noted that from the legislative act that established the OPA in December 2004, the OPA was operational and submitting recommendations to the Ministry by the time of its December 2005 annual report.[201]

5.2.8 Step 8: Establish and Refine Planning Processes

Projected Cost: High (>$250,000; Included in Up-Front and Operating Costs)
Projected Timeline: Ongoing

System planning will be one of the key functions of the single buyer model. To engage in a rigorous system planning process, the single buyer will need to a) assess existing planning processes and determine where, if any, implicit bias may be present b) understand the future expectations and prospective evolution of the electric power system and c) understand the current operational characteristics of the system. After gathering information on these three functions, the single buyer will also have the necessary tools to determine and evaluate prospective procurement opportunities. This includes the evaluation of any necessary infrastructure (in terms of generation and wires assets) and potential effects on system reliability and resilience. To accomplish this, the single buyer will need to establish the following:

- **Coordination mechanisms with the incumbent utility.** In either the outside or the inside single buyer approaches, the incumbent utility will retain ownership over distribution and transmission. For this reason, the single buyer must establish information sharing mechanisms with the incumbent utility to access the necessary information to aid its system planning. Such information sharing mechanisms will need to navigate confidentiality concerns of the utility.

  Such coordination mechanisms must also streamline information flows in the other direction – successful bids from the procurement process will need to be adequately integrated into operational oversight by the utility. The utility will need this information to exercise dispatch and maintain grid reliability.

- **Coordination mechanisms with the PUC.** Depending on the provisions outlined in the legislation, the single buyer will need to coordinate its efforts with the PUC powers and authorities. Traditionally, the PUC has held the role of evaluating the utilities' energy planning processes[202] and has begun to evaluate the utilities' Integrated Grid Planning

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[201] Ontario Power Auth., Ensuring Ontario's Electricity Future: 2005 Annual Report, Mar. 31, 2006, available at: http://cms.powerauthority.on.ca/sites/default/files/news/1713_2005_Annual_Report.pdf

[202] From 1990-2014, the PUC evaluated the utilities' Integrated Resource Plans (see e.g., Docket No. 2012-0036, Instituting a Proceeding Regarding Integrated Resource Planning, filed Mar. 3, 2012) which evolved into other evaluations in 2014, including PSIP evaluations (Docket No. 2014-0183, Instituting a Proceeding to Review the Power Supply Improvement Plans for [the HECO Companies], filed Aug. 7, 2014). See Box 15 for more detail.

process as well, which is intended to be an updated, more holistic energy planning process that will probably replace the IRP and PSIP processes.[203] In evaluating such plans, the PUC typically determines whether such plans conform with the expectations of the future utility system.

For example, it is possible that the legislature mandates that the planning efforts of the single buyer continue to undergo the scrutiny of the PUC. Alternatively, it is possible that, with the in-house capacity to undergo planning efforts and with no financial interest in planning efforts, it would be appropriate for the single buyer to undergo such planning towards state goals with reduced PUC oversight.

In any case, it will be necessary for the single buyer to have access to status and characteristics of grid infrastructure and other necessary information to undergo its planning process. Moreover, such information will inform the procurement process that is described in the following steps. Access to this information will continue to be held by the utility simply by its continuing ownership of distribution and transmission assets. Integrated and streamlined systems for information on key characteristics of the electricity grid is an essential capability of the single buyer for its functionality.

Box 15. Hawaii's Current Power Supply Planning Process

In 2014, the Hawaii PUC rejected the responses by the HECO Companies to the IRP process, describing the flaws of the Action Plans and the IRP report as "fundamental." The PUC subsequently determined that it was necessary to address the various issues that should have otherwise been included in the IRP docket through separate investigatory dockets and proceedings. The major components of this approach include:

- Power Supply Portfolio Reviews
- Inter-Island and Inter-Utility Power Transmission Reviews
- Distributed Energy Resources Reviews
- Achievement of the RPS Reviews
- Energy Efficiency Portfolio Standard Reviews
- Aligning Customer Interests and Public Policy Goals.[204]

[203] Docket No. 2018-0165, Instituting a Proceeding to Investigate Integrated Grid Planning, filed July 12, 2018.

[204] Decision and Order No. 32052, "Regarding Integrated Resource Planning," Docket No. 2012-0036, Filed April 28, 2014.

These reviews are clearly interrelated and often refer to each other. That noted, under a single buyer model, the single buyer will likely at minimum oversee the Power Supply Improvement Plan ("PSIP") process. Each of the PSIPs address resource planning, including actionable strategies and implementation plans to retire fossil generation, increase generation flexibility, and adopt new technologies. The IRP process outlined the principal issues that should be addressed in the PSIP process.[205] Moreover, they should seek to:

- Provide long-term analysis of integrated utility systems to inform evaluation of specific near-term capital investments and other decisions;
- Provide context and analysis to inform choices and trade-offs between major inter-related and/or mutually exclusive resource strategies;
- Provide assurance that the overall cost and rate impacts of utility system operations and proposed resource acquisitions are reasonable, economic, and affordable;

  Identify risks and uncertainties and inform the issues and trade-offs associated with resource acquisition and system operation decisions.

The plans required for the PSIP include a Fossil Generation Retirement Plan, a Generation Flexibility Plan, a Must-Run Generation Reduction Plan, and a Generation Commitment and Economic Dispatch Review, each with numerous specific requirements.

Notably, the PSIP process that is currently in use by the HECO Companies for its planning processes was meant to be a temporary solution following the flawed IRP process in 2014.[206] In response the HECO Companies' filed and improved PSIPs in December 2016 and their June 2017 draft report "Modernizing Hawaii's Grid for Our Customers," the PUC instructed the Companies to file a report with the Commission that would detail the Companies' planning approach to be used in the next round of integrated planning.

On March 1, 2018, the HECO Companies filed their IGP Report with the Commission, which proposes "an ambitious leap forward from traditional planning," that would merge three separate planning processes (generation, transmission, and distribution) while simultaneously integrating solution procurement into this merged process, with the goal of "identifying gross system needs, coordinating solutions, and developing an optimized, cost effective portfolio of

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[205] Order No. 30534, "Identifying Issues and Question for the Hawaiian Electric Companies; Integrated Resource Planning Process," Docket No. 2012-0035, Filed July 19, 2012. The first PSIP review occurred in Docket No. 2014-0183, Instituting a Proceeding to Review the HECO Companies' Power Supply Improvement Plans, filed Aug. 7, 2014.

[206] Order No. 35569, Instituting a Proceeding to Investigate Integrated Grid Planning, Docket No. 2018-0165, issued July 12, 2018, at 12.

assets."[207] Subsequently, the commission opened a docket to investigate Integrated Grid Planning and reaffirmed suspension of the IRP framework requirements for the HECO companies.[208]

Going forward, it is anticipated that the planning process will be based on the HECO Companies' new Integrated Grid Plan ("IGP"). Presumably, once the IGP is in operation, the Single Buyer will continue to oversee the resource planning within the IGP framework.

5.2.9 Step 9: Establish and Refine Procurement Processes

Projected Cost: High (Included in Up-Front and Operating Costs)
Projected Timeline: Ongoing

The next step is to establish the procurement processes by which the single buyer will operate. Some of these concerns will likely be addressed by the current open docket proceeding on the procurement of dispatchable renewable generation. This analysis will outline the current general approach towards the procurement process and briefly touch on various considerations for the competitive procurement process under a single buyer approach.

Generally, under the procurement process, the standard mechanism for procurement is to evaluate needs of the power system, draft a request for proposals (RFP), receive bids from interested parties, evaluate those bids, and obtain approval from the PUC for the selected bid. A thorough explanation of the competitive procurement process in Hawaii is outlined in Box 16.

Box 16. Hawaii's Current Competitive Procurement Process

In the Decision and Order No. 22588 of Docket No. 2003-0372, "Instituting a Proceeding to Investigate Competitive Bidding for New Generating Capacity in Hawaii," the PUC outlined the framework that continues to guide competitive bidding in Hawaii. In the Framework, the PUC outlined the roles of various actors – the utilities, the PUC, the independent observer, and the bidders – as well as the general RFP process. The following summarizes some of the key points of that process:

- **Design of an RFP**, which identifies any unique system requirements, resource attributes and criteria for the evaluation. The RFP also includes bidding guidelines and requirements, and evaluation and selection criteria, as well as risk factors. It also includes proposed forms of PPAs and other contracts, with certain terms or stipulations addressed.

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207 *Id.*, at 12-13.

208 Order No. 35569, Instituting a Proceeding to Investigate Integrated Grid Planning, Docket No. 2018-0165, issued July 12, 2018, at 12, 19.

- **Issuance of the RFP**, which is provided with adequate notice and through utility encouragement of participation from bidders. It also includes a formalized process to answer any of the bidders' questions.

- **Development and Submission of proposals by bidders.** The utility self-bid must be submitted one day in advance of the deadline specified in the RFP.

- **A "multi-stage evaluation process"** to reduce bids down to a short list, which is determined through receipt, completeness, initial evaluation of price and non-price, a detailed evaluation or portfolio development, and final section of the short list.

- **Contract negotiations.** The utility can negotiate amongst the short list bidders. Some examples of items that could be negotiated include project operating characteristics and fuel supply arrangements.

- **Commission approval.** The PUC ensures that the process was fair, consistent with the integrated resource plan, represent best practices, and align with the public interest. The PUC can review, approve, or reject the contracts that emerge from this process.

The single buyer will be tasked with fulfilling at a minimum the various tasks outlined in Box 16. In doing so, it should seek the capabilities outlined in Box 14, but should also develop the mechanisms and forums – such as websites, submission forms, conferences, and service personnel – that can issue RFPs, collect bids, and answer any related questions to the procurement process. The single buyer should clarify any outstanding questions about its relationship and interaction with other entities, such as the PUC. For example, one of the key questions that could potentially arise in the establishment of the single buyer includes whether the PUC will continue to review the outcomes of the procurement process, or whether the single buyer will possess quasi-regulatory authority over its own procurement without PUC approval.

The questions raised and resolved in the studies during Step 2 – and the answers to them – will be reflected in the process of establishing procurement processes. Whether and to what extent the legacy utility can participate in the RFP process remains open to deliberation, as discussed above in Section 5.2.2.3.

5.2.10 Step 10: Commence Operations

Using the coordination and management processes established, the single buyer can undertake the responsibilities of integrated resource planning[209] and procurement of the generation capacity

[209] Or Integrated Grid Planning, if the IGP has replaced the IRP by the time the Single Buyer model is implemented. *See*, Order No. 35569, Instituting a Proceeding to Investigate Grid Planning, Docket No. 2018-0165, filed on July 12, 2018.

necessary to fulfill such requirements. That noted, over time, the single buyer will likely adjust and reform its mechanisms.

5.3 Summary of Distinctions between the Outside and Inside Single Buyer Models

Overall, the key distinctions in the implementation of the outside and inside single buyer models depend in part on their distinction as public versus private entities. If the single buyer functions remain within the utility, it may be easier to transition by simply utilizing the in-house capacity of the utility. However, this approach also comes with some caveats; the conflict of interest concern is likely more acute in the "inside" single buyer model given the proximity and relationships that previous employees will have had with the incumbent utility. The "outside" single buyer model, in contrast, does not necessarily need to "ring-fence" but instead must ensure that there is no conflict of interest. These distinctions also have potential effects on the legitimacy of the single buyer entity itself.

Moreover, it may be legally feasible for the PUC to establish the "inside" single buyer and ring-fencing through docket consideration alone, relative to the "outside" single buyer, which would likely require legislative action to initially fund the single buyer entity. However, this may be an inconsequential distinction, since the legislative action is likely desirable in either case to impose a mandate to establish a single buyer model and support the long-term establishment and public legitimacy of the single buyer.

In other respects, the outside and inside single buyer models are similar; both will need approximately the same capabilities and resources to pursue their mission effectively. Both, with adequate ring-fencing, or conflict of interest mitigation, would can achieve their missions effectively; there is no reason to believe that either version would be innately precluded from doing so.

5.3.1 Unique cost factors for achieving the 100% RE vision

The effectiveness of the single buyer model to achieve the 100% RE vision in Hawaii is premised on the model achieving several effects on the supply of electricity. First, a single buyer would seek lower prices from IPPs by virtue of being an independent agency – either inside or outside the incumbent utility – with the mandate to seek the lowest possible energy prices for consumers.

Ideally, this model would generate cost savings that are greater than the additional cost of establishing the single buyer entity itself. Because the single buyer is not beholden to the interests of shareholders, it would have aligned incentives to pursue and achieve its mission of lowered costs for consumers, particularly when incorporated and established by the initiative of the Hawaii State government and under oversight by the PUC.

The second possible means by which the single buyer could reduce the cost of achieving the 100% RE vision is by allowing for system planning in a way that best procures renewable energy in a way that meets the 100% RE vision. Situating the planning processes within the single buyer would mitigate against the risk and incentive of the utility overcapitalizing its assets to achieve greater returns on equity through greater state oversight and control over the process.

5.3.2 Conclusion on steps and associated costs

The single buyer model is subject to significant uncertainty with regards to its cost and the steps required for its establishment. Some of this uncertainty lies in the fact that Hawaii would be the first adopter of an explicit single buyer model in the United States; thus, the empirical data for single buyers in similar context applicable Hawaii is lacking. Moreover, the specific version of the single buyer described in this section is not like single buyers generally implemented in an international context. The other uncertainty resides in the form and accompanying regulation of the single buyer model. Several key questions, such as the status of the single buyer as a temporary or permanent entity, whether it will be outside or inside of the utility, and whether the incumbent utility can participate in the procurement process are all open to further discussion.

The Project Team roughly estimates that the "Year One" operating costs of the single buyer in Hawaii will approximately range in a similar order of magnitude to the budget of the Hawaii PUC. While the Project Team's figure estimates approximately $2.9 million total for the first year, there are many reasons to consider this to be a low overall estimate. Moreover, the undetermined factors mentioned above will also impact the overall cost of the single buyer model. Generally, the Project Team estimates that the establishment of the single buyer model could take between three to five years, with significant variability based on intervening factors, such as the potential contentiousness of legislative and PUC actions.

5.4 Legal Considerations

The following section will outline some of the key legal considerations for the establishment of the "outside" and "inside" single buyer models.[210] It will evaluate the key legal concerns pertaining to establishment, funding, and subsequent operation, with a focus on the integrated resource planning[211] and the competitive procurement process. For the establishment of the single buyer, this analysis considers the legal basis of policy venues for establishing the PUC, including when action – either by the PUC or the Hawaii state legislature – might be required. For funding, the following analysis considers possible sources of up-front funding for the single buyer, from government-issued bonds (for the establishment of the "outside" single buyer model) and investment by the utility itself (in the "inside" single buyer model) with subsequent recoupment of costs through the rate base. Finally, for the operation of the utility, our analysis highlights some of the considerations for competitive procurement and system planning, including all necessary

[210] The Project Team defines an "outside" single buyer model as a governmental entity that lies outside the purview of the incumbent public utility.

[211] While the chapter focuses on Integrated Resource Planning because that framework is well established and would be an important factor if valid when the SB is implemented, it is important to note the ongoing investigative docket on Integrated Grid Planning, which may replace the IRP framework. *See*, Docket No. 2018-0165, Order No. 35569, Instituting a Proceeding to Investigate Grid Planning, filed on July 12, 2018

measures for imposing ring-fencing and adequate conflict of interest provisions in associated Codes of Conduct and Frameworks.

5.4.1 Legal Considerations for Establishment

The following section outlines the legal authority for the establishment of the single buyer. It will proceed to outline the general means by which governmental entities (in this case, the legislature and the PUC) could possibly establish the single buyer; unique circumstances under which legislative action might be necessary; and the legal basis for the PUC acting on its own volition.

The Hawaii government has latitude with regards to the prospective means by which certain governmental entities – in this case, the legislature and the PUC in particular – would ultimately establish the single buyer model. Generally, the PUC possesses broad powers and authority to establish and enforce policy with regards to public utilities within the bounds of its legislative directive. In this respect, the PUC is designed to tackle and craft approaches towards challenging technical issues. However, the legislature often provides mandates or guidance for the PUC in its decision-making with varying levels of specificity. Box 17 outlines the range of actions that can be taken with regards to legislature and the PUC. These can range from statutes with no specific guidance that relies entirely on PUC determinations, to statutes that specify standards and make decisions for the agency itself.

This suggests that the legal responsibility for implementing the single buyer model could vary significantly subject to the will and desires of the legislature. However, there are scenarios in which the legislature must be involved by necessity. One of these potential scenarios is if the franchises granted to each of the HECO Companies are amended to reflect the single buyer.[212] While amendment of the franchise agreement is not necessary for the establishment of the single buyer, the legislature may wish to set bounds on the terms of the agreement for a variety of reasons. These might include:

- Clarifying the role of the franchisee; for example, clearly outlining in the agreement that certain privileges of supply will be held by the Single Buyer, and that the franchisee will retain privileges limited to other capabilities, such as distribution and transmission. Such clarification may be especially pertinent in the case of an "outside" single buyer, in which the utility may relinquish control over some of its previously held privileges in the generation sector.

- Seeking any potential adjustments to the franchise fee imposed on utilities if desired. The single buyer model, and/or any accompany restructuring of the electricity sector, may

[212] The franchise agreements are available in Docket No. 2015-0022, Applicants' Response to LOL-IR-38, Filed Apr. 20, 2015, Attachment 1 ("HECO Franchise"); *id.*, Attachment 2 ("HELCO Franchise"); *id.* Attachment 3, at 1-4 ("MECO Maui Franchise"); *id.*, Attachment 3, at 5-8 ("MECO Lanai Franchise"); Attachment 3, at 9-12 ("MECO Molokai Franchise"). Section 2 of each agreement outlines the right, authority, and privilege of the franchise to manufacture, sell, furnish, and supply electric light, electric current, or electric power within each of their respective jurisdictions.

affect the gross receipts of the incumbent utility and hence the revenues to the affected counties.

- Inclusion of provisions on price and quality, electric service, state goals, or other community goals.

These are some of the potential reasons to amend of the franchise agreements with the HECO Companies. However, as noted above, amendment of the franchise agreement is not *necessary* to implement the single buyer model, although such an act may offer an opportunity to align the relationship with the HECO Companies with state goals and the single buyer model. If the local communities seek to amend such franchises, the legislature holds the authority to do so, as outlined in the concluding provisions of each of the respective franchise agreements.[213]

Beyond amendment of franchise agreements, the legislature can also impose change by directly changing statutory law. Each of the HECO Companies' agreements provides that the utilities' rights under their respective franchises are subject to other laws that may be applicable to electric utilities in Hawaii. Therefore, according to the franchise agreements, the Hawaii state legislature can seek to amend HRS Chapter 269 to direct the implementation of a single buyer model, and such law would be binding, provided that the utility can appeal from any ruling, decision or order issued by the PUC as provided by law.

Box 17. The Scope and Specificity of Legislative Mandate

The degree of which the legislature can provide guidance to the PUC can vary significantly. Carl Freedman of Haiku Design and Analysis and Jim Lazar at the Regulatory Assistance Project have outlined the degrees of which statute can require, encourage, or provide guidance (or a lack thereof) on outcomes at the PUC or its evaluation of certain considerations in the context of procurement reform in Hawaii. For a spectrum of least specific to most specific and direct in mandate, see the following list:

Statutes can:

- provide no specific guidance, relying entirely on the agency's discretion in policy matters within the agency's proscribed powers and duties.
- give powers to the agency to consider specific factors or take specific actions.
- give general direction to the agency to consider specific factors or take specific actions.
- require agencies to consider specific factors.

[213] See HELCO § 16; HECO Franchise § 18, MECO Maui Franchise § 17; and MECO Lanai Franchise § 17; MECO Molokai Franchise § 17.

- require agencies to determine and adopt rules to consider specific factors.
- require agencies to determine and adopt standards.
- require agencies to determine and adopt standards as rules.
- require agencies to determine and adopt standards with minimum or specific characteristics as rules.
- specify standards, make decisions for the agency or require specific agency actions.

Source: Freedman, Carl and Jim Lazar, "Hawaii Energy Utility Regulation and Taxation: Practice, Policy and Incentives for Energy Efficiency, Renewable and Distributed Energy Resources, July 11, 2003, Hawaii Energy Policy Project, p. 30.

5.4.1.1 Legal Considerations for Establishment: The "Outside" Single Buyer

With regards to the difference between "inside" and "outside" single buyer models, the "outside" single buyer model will almost certainly require enabling legislation. As discussed above, the "outside" single buyer will require creation which can be accomplished through the establishment of a governmental agency of the Hawaii State Government or as a non-share, non-profit organization contracted by a public agency. The Hawaii Technology Development Corporation[214] and the Hawaii Green Infrastructure Authority[215] provide examples of semi-independent governmental agencies while the Public Benefits Fee Administrator (Hawaii Energy)[216] provides an example of a contracted non-profit. The contracted non-profit model may provide greater flexibility for funding, staffing, and procurement and slightly less political influence than a governmental agency.

It is unlikely that an "outside" single buyer would be considered a public utility under HRS § 269-1 because the single buyer would sell all of the electricity it purchases directly to the HECO Companies, which are public utilities, for transmission or distribution to the public.[217]

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[214] See HRS Chapter 206M.

[215] See HRS §§ 196-63 through -70.

[216] See HRS §§ 269-121 through -125.

[217] Under HRS § 269-1, the definition of public utility excludes "Any user, owner, or operator of the Hawaii electric system-as defined under section 269-141," in which HRS § 269-141 states that "any person, business, organization, or other entity who:

> (1) Owns, controls, operates, or manages plants or facilities for the generation, transmission, or furnishing of electricity; and

Additionally, even if it were a public utility, an "outside" single buyer that is a governmental agency is exempt from regulation under HRS Chapter 269.[218] Except where the legislature has expressly granted jurisdiction or responsibility in certain matters,[219] the PUC's authority and general investigative power is limited to public utilities.[220] Accordingly, absent legislation expressly conferring the PUC with the power to regulate the single buyer, the PUC's ability to regulate the single buyer entity would be limited to regulating the utilities' transactions with the single buyer.

5.4.1.2 Legal Considerations for Establishment: The "Inside" Single Buyer

It is possible that the "inside" single buyer may not need enabling legislation. In the case of the "inside" single buyer model, the utility is functionally performing responsibilities similar to those that it had performed before (assuming that the single buyer is only performing procurement and planning); the difference is that the ring-fencing further segregates the capabilities and assets performing these responsibilities from the other activities of the utility. Moreover, since the utility will continue to house the key functions of procurement, it arguably still maintains its privileges under the franchise agreement, albeit with more stringent guidelines. Both processes – procurement and planning – have precedent in prior PUC guidance and action. It is within the realm of possibility that the PUC may have latitude in further shaping these functions without legislative action.

However, absent legislative action, there is no requirement for the PUC to take the initiative to implement the "inside" single buyer construct. As such, the implementation of a single buyer program may be deprioritized in order to focus attention on those programs for which there is an

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> (2) Provides, sells, or transmits all of that electricity, except such electricity as is used in its own internal operations or is used for its own consumption, directly to a public utility for either transmission or distribution to the public."[217]

Since the single buyer entity would arguably provide that electricity to the public utility for eventual transmission or distribution to the public, the single buyer entity would likely not be defined as a "public utility" under Hawaii statute.

[218] HRS § 269-31(a).

[219] See, e.g., HRS § 269-122(b) (extending the PUC's regulatory authority to the public benefits fee administrator).

[220] See HRS § 269-6 ("The public utilities commission shall have the general supervision hereinafter set forth over all public utilities and shall perform the duties and exercise the powers imposed or conferred upon it by this chapter."). HRS § 269-7 ("The public utilities commission and each commissioner shall have power to examine into the condition of each public utility . . . and all matters of every nature affecting the relations and transactions between it and the public or persons or corporations.").

express legislative mandate, such as community-based renewable energy.[221] Even with legislative action, if there is no mandate, the PUC may not take action.[222]

As with the "outside" single buyer, if the "inside" single buyer is created as a separate legal entity from the franchised utility,[223] the single buyer is likely to be excluded from the definition of "public utility" under HRS § 269-1 because the single buyer would sell all of the electricity it purchases directly to the HECO Companies, which are public utilities, for transmission or distribution to the public.[224] For this reason, absent legislation expressly conferring the PUC with the power to regulate the single buyer, the PUC's ability to regulate the single buyer entity would be limited to regulating the utilities' transactions with the single buyer. This only applies if the "inside" single buyer is a separate legal entity.

There are no reasons why the establishment of the single buyer would be outright legally unfeasible; there is significant latitude over how the initial studies and eventual establishment could occur. However, the establishment of the single buyer presents a range of considerations that either necessitate likely action by the legislature and certainly by the PUC. In both cases, the

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[221] See HRS § 269-27.4.

[222] See, e.g., Act 166 (2012), in which the legislature authorized, but did not require, the PUC to contract with a Hawaii Electricity Reliability Administrator (HERA) to develop and implement local reliability standards and interconnection requirements with accompanying enforcement in a manner comparable to the role filled on the mainland by the North American Electric Reliability Corporation and the regional oversight entities. See Act 166, S.L.H. 2012 § 1 Act 166, S.L.H. 2012 § 1; HRS Chapter 269, Part IX.

[223] An "inside" SB that is established as a separate entity could theoretically be structured as an entity within the HECO Companies (serving as the single buyer for all three individual subsidiary utilities but having 3 divisions, each working with each subsidiary), as a separate entity within HECO, HELCO, and MECO individually, or as an entity within Hawaiian Electric Industries, the corporate parent of the HECO company and having 3 divisions, each working with each subsidiary. While there may be specific legal factors governing the placement of the single buyer within the utility's corporate structure, we do not assess this placement to have a significant impact on the need for ring-fencing or its status as an "inside" single buyer."

[224] Under HRS § 269-1, the definition of public utility excludes "Any user, owner, or operator of the Hawaii electric system-as defined under section 269-141," in which HRS § 269-141 states that "any person, business, organization, or other entity who:

> (1) Owns, controls, operates, or manages plants or facilities for the generation, transmission, or furnishing of electricity; and
>
> (2) Provides, sells, or transmits all of that electricity, except such electricity as is used in its own internal operations or is used for its own consumption, directly to a public utility for either transmission or distribution to the public."[224]

Since the single buyer entity would arguably provide that electricity to the public utility for eventual transmission or distribution to the public, the single buyer entity would likely not be defined as a "public utility" under Hawaii statute.

PUC would have to play a role in establishing the single buyer given the role that the single buyer will serve in the engagement of public utilities with IPPs.

5.4.2 Legal Considerations for Funding

The following section will outline the legal considerations for the initial funding of both single buyer models and means for funding those single buyer models over time. The legal considerations for the funding of the single buyer depend on the categorization of the single buyer in terms of its status as "inside" or "outside" the utility, and of course, how the single buyer is funded. For the single buyer "outside" the utility, this analysis considers initial financing through government bonds for a governmental entity and similar tax-exempt bonds for a nonprofit entity. As discussed above, the "outside" single buyer may be ratepayer funded as are energy efficiency programs administered by Hawaii Energy under the Public Benefits Fee, pursuant to HRS Chapter 269, Part VII. If the single buyer remains "inside" the utility, this analysis considers funding through the traditional means of utility funding, which entails rate-basing the expenditures and costs of providing public services. The ongoing operational costs of the single buyer could be funded through a user charge or transaction fee.

5.4.2.1 Legal Considerations for Funding: The "Outside" Single Buyer

For an "outside" single buyer entity, one possible version of its establishment is operation as a governmental agency of the Hawaii State Government. In this case, the initial funding would likely come from some form of bond issuance. Under the Hawaii Constitution, bond issuances must be authorized by an act of the legislature. The general requirements for the State to issue debt are outlined in Article VII of the Hawaii Constitution,[225] and Title 5 of the Hawaii Revised Statutes. These include the requirement for legislative appropriation and the general fund expenditure ceiling.[226] If the single buyer is funded by bonds, the most likely source of initial funding to establish the single buyer would likely come from general obligation bonds, which are "bonds for the payment of the principal and interest of which the full faith and credit of the State or a political subdivision are pledged […]"[227] or revenue bonds, which are "all bonds payable from the revenues, or user taxes, or any combination of both, of a public undertaking, improvement, system or loan program and any loan made thereunder and secured as may be provided by law."[228]

The difference between these two bonds is that the revenue bond is backed by a specific revenue stream, while the general obligation bond is backed by the full faith and credit of the State. Thus, if the single buyer entity is to be funded by revenue bonds, it should generate some revenue

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[225] Haw. Cons. Art. VII § 12.

[226] Haw. Const. Art. VII §§ 9, 13.

[227] Haw. Cons. Art. VII § 12-2.

[228] Hawaii Cons. Art. VII § 12-8.

stream, such as user or transaction charges. Absent these charges, general obligation bonds are more appropriate for funding the "outside" single buyer.

It is unclear whether the "outside" single buyer model could also qualify for the "special purpose revenue bond," since such bonds are intended to assist utilities serving the public, among other unrelated entities. An initial reading seems to indicate that the outside single buyer would not qualify as a public utility.[229] However, were the single buyer to qualify as a public utility, then it may be able to qualify for special purpose revenue bonds. This would require a two-thirds vote of the legislature to enact enabling legislation for the issuance of special purpose revenue bonds for the single buyer entity, and by separate legislative bill, another two-thirds vote to issue special purpose revenue bonds for the project itself, provided that the issuance is found to be in the public interest.

Alternatively, another arrangement for funding could be through the PUC. Since the PUC already collects revenue fees from the public utilities in a special fund,[230] and then contributes all moneys more than $1,000,000 to the state general fund, the single buyer could plausibly be funded through those fees. These funds currently reimburse the Departments of Commerce and Consumer Affairs for all oversight and administrative functions in line with legislative appropriations.[231] The legislature, through an act, could amend HRS § 269-33 to include disbursements to the single buyer for its administrative costs. Alternatively, if the single buyer is housed within the PUC itself, it could simply be part of the budget of the PUC.

Government financing is also pertinent in the case of an "outside" single buyer that is a nongovernmental nonprofit. There are a variety of means by which this could happen; either as a HRS Chapter 42F grant to the nonprofit appropriated from the general fund, or as a "special fund," or funding such an entity with municipal bonds. Governmental financing with bonds would bear some similarity to the case of the OPA, which was an "outside" single buyer that was funded by the Province of Ontario. In the case of the Ontario Power Authority (OPA), the OPA

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[229] Under HRS § 269-1, the definition of public utility excludes "Any user, owner, or operator of the Hawaii electric system-as defined under section 269-141," in which HRS § 269-141 states that "any person, business, organization, or other entity who:

> (1) Owns, controls, operates, or manages plants or facilities for the generation, transmission, or furnishing of electricity; and
>
> (2) Provides, sells, or transmits all of that electricity, except such electricity as is used in its own internal operations or is used for its own consumption, directly to a public utility for either transmission or distribution to the public."[229]

Since the single buyer entity would arguably provide that electricity to the public utility for eventual transmission or distribution to the public, the single buyer entity would likely not be defined as a "public utility" under Hawaii statute.

[230] HRS § 269-30.

[231] HRS § 269-33.

had a significant credit line from the Ontario Financing Authority, allowing it to borrow from the Province of Ontario. It also possessed a services agreement in which the Province would provide all the OPA's borrowing and investment services. As for ongoing revenue, the OPA earned its revenues through the fees it charges to Ontario electricity consumers, registration fees, and interest revenue.[232] The regulations for the OPA further outlined conditions by which the OPA would be able to borrow funds and make investments, which could similarly be outlined in the case of Hawaii to manage the financial risks of the single buyer.[233]

Finally, if the single buyer is funded through surcharges on ratepayers, then the legislature would likely need to outline such provisions within statute or provide guidance to the PUC on determining the extent of those surcharges. This has some precedent; for example, HRS § 269-33 outlines possible additional surcharges for the maintenance of public utility assets in emergency situations, such as a natural disaster. As discussed above, HRS § 269-121 authorizes a public benefits fee for demand side management programs, and HRS § 269-146 authorizes the PUC to require an electric reliability surcharge to fund a potential HERA, among others. A similar provision could be provided for a single buyer entity. In drafting such a provision, using language similar to that in HRS §§ 269-121 and -122, which creates a fee that is collected by the utility and transferred to the contracted non-profit as opposed to a fund established or maintained by an agency, may provide greater flexibility in the non-profit's ability to budget and expend moneys collected through the fee.

In sum, funding the "outside" single buyer entity would likely entail a legislative act that could, among other items, 1) authorize a bond issuance, grant, and/or establishment of a special fund for the initial establishment of the single buyer (either governmental or non-profit) and 2) authorize the PUC to establish a surcharge for the funding of the single buyer. Of course, this assumes certain configurations of the "outside" single buyer model; another prospective arrangement could be housing the single buyer within the PUC itself and funding its activities with the fees already imposed on public utilities. There are a variety of legal means by which the legislature could fund the single buyer; the details will depend on the specific arrangement of the outside single buyer and which entities bear its cost.

5.4.2.2 Legal Considerations for Funding: The "Inside" Single Buyer

For a single buyer housed "inside" the utility, there are additional considerations. For one, the functions of the new single buyer – procurement and resource planning – can plausibly continue to be included as part of the cost recovery mechanism and evaluated through continuing rate case proceedings. As such, the costs of the single buyer would be reflected in electricity rates that are regulated by the PUC. However, if the "inside" single buyer is a nonprofit and non-share entity, there should ideally be no return on equity invested in the "inside" single buyer (since it is a non-

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[232] "Ontario Power Authority" DBRS, July 7, 2010, Credit Rating, available at: http://www.ontla.on.ca/library/repository/mon/25001/306933.pdf.

[233] "Ontario Power Authority – Eligible Investments and Borrowing," Electricity Act, 1998, Ontario Regulation 423/04, available at: http://www.ontla.on.ca/library/repository/mon/25001/306933.pdf.

share entity, there is no "equity" to be held by investors), only recovering its upfront and operating costs.

Note that the Frameworks from PUC Orders for both competitive procurement and integrated resource planning both state that the utility can recover the costs of these mechanisms. In the Competitive Bidding Framework, the document notes:

> "The costs that an electric utility reasonably and prudently incurs in designing and administering its competitive bidding processes are recoverable through rates to the extent reasonable and prudent."[234]

In the case of the Framework for Integrated Resource Planning:

> "The utility shall be entitled to recover its integrated resource planning and implementation costs that are reasonably incurred as determined by the Commission. The utility shall record costs associated with its integrated resource planning process in separate accounts to allow review of the actual costs incurred as compared to the forecasted costs presented in each rate case or other equivalent cost-recovery mechanism."[235]

These mechanisms would not necessarily change even if and when the PUC shifts to use an updated planning framework; although additional stipulations might seek to align the cost recovery of these activities with the nonprofit status of the single buyer entity. As such, like the Framework for Integrated Resource Planning or the likely forthcoming framework for Integrated Grid Planning, the competitive procurement activities of the Single Buyer should also be tracked in a separate account. Moreover, such activities should be accountable only to a legally distinct single buyer entity that is ring-fenced from the utility.

Of course, this is a potential scenario in which the legislature is not involved in establishing the single buyer. If the legislature is involved, it could provide more guidance to the PUC on how to initially fund the single buyer and ensure its solvency. If the legislature acts, the options at its disposal will be not unlike the options listed under the "outside" single buyer model, with the exception that it will be unlikely to issues some of the kinds of bonds outlined because the "inside" single buyer is not a state entity.

Thus, while there is a preexisting legal framework for cost recovery for both functions of the "inside" single buyer model, some modifications may be necessary to align such cost recovery with the nature of the single buyer model in terms of its legal (non-profit and non-share) status.

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[234] Framework for Competitive Bidding, at 30.

[235] Framework for Integrated Resource Planning, at 21.

5.4.3 Legal Issues Related to Operation

While there are many legal considerations for the operation of the single buyer, this analysis will focus on the necessary legal changes to the Frameworks and Codes of Conduct pertaining to procurement and planning. It will also highlight any considerations that may distinguish the "inside" and "outside" single buyers in terms of these activities, as well as workforce management. One key source of difference emerges if the "outside" single buyer operates as a governmental entity, rather than a nongovernmental non-profit entity or "inside" the utility itself. Each of these domains has consequent implications for how the single buyer will be operated.

5.4.3.1 Legal Issues Pertaining to the Workforce

With regards to the workforce, one key distinction between the "inside" and the "outside" single buyer models pertains to whether the outside single buyer is a public-sector institution. If so, the "outside" single buyer would likely have to adhere to civil service regulations regarding its hiring and employees. These civil service regulations are outlined in HRS Chapter 76 Civil Service Law and HRS Chapter 78 Public Service, which outline the civil service laws and public service law for public officers and employees. Qualification for civil service can entail steps that may not be necessary in the private sector; for example, one major distinction is the common practice of having all applicants taking civil service exams for placement on eligibility lists.[236] Moreover, civil service is guided by broader rules, regarding layoff, suspension, demotions, merit appeals, etc. that my limit the managing flexibility of the "outside" single buyer. [237] This affects the timeline of hiring and long-term workforce management, although how it may differ from private sector hiring is unclear given the variety of approaches of workforce management in the private sector. With that noted, HRS § 76-16 outlines numerous categories of exemptions by which certain individuals can be exempt from civil service requirements. [238]

As a part of the hiring process, conflict of interest provisions will likely differ between the workforces of the "inside" and "outside" single buyer models. In the "inside" model, there will likely be a greater emphasis on ring-fencing personnel – both physically and in terms of virtual access to sensitive information – while in the "outside" model, there will likely be a greater emphasis on conflict-of-interest with all generators, utility and IPPs included.

These factors suggest that there is a legal framework for managing these concerns and that there are not insurmountable hurdles to the legal feasibility of either the "inside" or the "outside"

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[236] See HAR Chapter 14-3.01. It is possible to hire without having to take a written exam; this can include an "unassembled" examination in which applicants are simply based on the education and experience listed on their application. See: State of Hawaii, :Dept. of Human Resources Development, "FAQs (Frequently Asked Questions) and Answers," http://dhrd.hawaii.gov/job-seekers/job-faqs/; see also HAR § 14-1-15

[237] See generally HAR Title 14.

[238] HRS § 76-16.

models in terms of workforce management. However, these legal frameworks for public and private workforces, embedded in statute, raise management issues that merit greater scrutiny.

5.4.3.2 Legal Issues Pertaining to Procurement

One unique element that must be addressed in the case of the "outside" single buyer that is a government agency is Hawaii's Public Procurement Code, HRS Chapter 103D. While the PUC has developed a comprehensive Competitive Bidding Framework which could be amended to suit the needs of the single buyer, all procurement contracts made by governmental bodies are subject to the Public Procurement Code unless expressly exempted by statute.[239] Any enabling legislation should consider whether an exemption from HRS Chapter 103D is appropriate.

One of the key principles guiding the single buyer with regards to the procurement process centers on ensuring the independence of the single buyer. In this case, a primary concern is that if the single buyer is not adequately ring fenced from utility, then it will serve the interest of utility shareholders rather than seeking lowering costs for ratepayers. A second concern would be the perception among IPPs of utility bias towards its own generation assets in competitive procurements. In both the case of the "inside" and "outside" single buyer, both concerns can be respectively addressed by ring fencing and conflict-of-interest mitigations for all transferred employees and for any new employees.

As previously noted, the status quo in Hawaii currently implements a version of the single buyer model, in which the utility is a single buyer of electricity under long-term PPAs through either the Framework for Competitive Bidding or via PURPA requirements. The utility faces little financial incentive to ensure the lowest prices from IPPs in the status quo because all power purchase costs are recovered by the utility from the customer base through adjustable surcharge, although the utility or PUC may make price one of various criterion during the evaluation process. This adjustment charge mechanism is grounded in HRS § 269-122,[240] and reflected in the Energy Cost Adjustment Clause (ECAC) and Purchased Power Adjustment Clause (PPAC) rates.[241]

Whenever a utility enters into an agreement exceeding $300,000 with an "affiliated interest", including any entity with common ownership exceeding 10% of the entity and the utilities voting shares or having directors in common with the utility exceeding more than one-third of the total number of the utility's directors, that agreement must be filed with the PUC and the PUC can review the agreement to determine if it is in the public interest.[242] To the extent an "inside" single

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[239] HRS § 103D-102(a).

[240] HRS § 269-122

[241] See, e.g., Tariff Applicable to Electric Service of Hawaiian Electric Company, Inc., Purchased Power Adjustment Clause, Revised Sheet Nos. 63-63E (ECAC), 94-94B (PPAC).

[242] HRS § 269-19.5.

buyer meets these requirements, there may be a requirement to file agreements between the utilities and the single buyer with the PUC.

The requirements in the Framework for Competitive Bidding, with the intent of separating teams that offer self-build options from the utility during the procurement process from the procurement and bid evaluation teams, bear relevance to addressing these challenges. These measures are embodied in the Codes of Conduct of the Framework for Competitive Bidding.[243] These Codes of Conduct were reviewed in Docket No. 2017-0352 relating to renewable generation procurement. Expressed concerns include:

- The Consumer Advocate has noted that the Code of Conduct is only intended as a guideline and does not instill confidence that they will be mandatorily followed;
- Some IPPs have noted that the allowance for the use of "Shared Resources" and "Unassigned Company Resources" on both the RFP and Self-build teams remains hidden from bidders and could potentially lead to bias towards the utility during the procurement process;
- There is ambiguity in the code with regards to which personnel are subject to the code.[244]

The legal changes that may accompany a single buyer should seek to address and clarify these questions in a manner that strengthens the ability of the single buyer to address the previously mentioned problems. As noted in the "steps" section, the single buyer should seek to fully segregate the personnel and assets of the single buyer from the incumbent utility and mitigate potential conflicts of interest. In the "inside" single buyer approach, this would entail modifying the Codes of Conduct in the following fashion:

- Expanding the Code of Conduct beyond the procurement/self-build teams to the procurement/utility more broadly;
- Mandating the Code of Conduct, including appropriate incentives, as opposed to suggesting it as guideline;
- Clarifying ambiguity as to which personnel are subject to the code by requiring legally distinct and branded entities with separate accounting procedures to undertake the role of the single buyer;

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[243] The PUC has also opened an investigative docket to receive comment on its Draft Affiliate Transaction Requirements & Code of Conduct. *See*, Docket No. 2018-0065, Order No. 35363 Opening Docket, filed March 22, 2018.

[244] See Docket No. 2017-0352, Order No. 35224, "Providing Guidance on the Hawaiian Electric Companies' Proposed Requests for Proposals for Dispatchable and Renewable Generation," Issued Jan. 12, 2018, at 13-14; *see also, Docket No. 2017-0352, Code of Conduct Procedures Manual for the Competitive Bidding Program, filed on February 27, 2018.*

- Outlining greater ring-fencing procedures in terms of information technology, personnel, etc., with no individuals allowed overlapping roles; and

- Describing additional responsibilities for hiring for the single buyer that are not under the purview of the human resources department of the incumbent utility.

Of course, these concerns are particularly acute in the case of a "inside" single buyer that can participate as a bidder in the procurement process. However, even if the "inside" single buyer cannot participate as a bidder (and thus somewhat addressing the self-bias perception outlined above), these measures could still help ensure that mission of the single buyer remains focused on ratepayer benefits, rather than shareholder returns. As for the "outside" single buyer approach, these Codes of Conduct still bear relevance, although controls to preserve independence in such an entity need not be as explicitly focused on ring-fencing.

Finally, in certain situations, the Competitive Bidding Framework also requires the designation of an Independent Observer to oversee the procurement process.[245] The Independent Observer is drawn from a list approved by the PUC that is sourced from all participants in the competitive bidding process; the utility then selects the Independent Observer, subject to final PUC approval. The advisory, monitoring, and reporting responsibilities of the Independent Observer include all phases of the procurement process with the goal of reducing of utility self-bias. This includes, among other things, certifying to the PUC that each step of the procurement process led to no unfair advantage for the utility; advising the utility on its decision-making; monitoring all communications between the utility and its affiliates, including any negotiations, among others. Under the single buyer approach, this Independent Observer should be sufficiently empowered to ensure the absence of discrimination amongst bidders and adherence to the procurement principles, which is already clearly reflected in the current Framework. However, the responsibilities of this role may have to be updated for the more rigorous ring-fencing and conflict-of-interest provisions outlined above.

In summary, the single buyer would require significant changes to the Codes of Conduct outlined in the Framework for Competitive Bidding; in general, these changes would include substantially greater legal enforcement, broader application, and greater focus on the principles of the single buyer described throughout this section. These changes are feasible but the extent of which they may require legislative acts may depend on the provision in question.

5.4.3.3 Legal Issues Pertaining to Planning

The procurement process typically draws upon the issues that are outlined in the PUC's evolving planning process: Integrated Resource Planning (IRP) (1990-2014), PSIP (2014-2017), and a proposed Integrated Grid Planning (IGP) process.[246] The framework for Integrated Resource

[245] Competitive Bidding Framework, at 13-16.

[246] *See*, Docket No. 2018-0165, Order No. 35569, Instituting a Proceeding to Investigate Grid Planning, filed on July 12, 2018 (Order 35569), at 6-13.

Planning was outlined in the Decision and Order issued on March 14, 2011, in Docket No. 2009-0108. The stipulations guiding the PSIP process are drawn from the IRP guidance and further elaborated on in numerous subsequent documents, such as the rejection and approvals of PSIP Filings.[247] The proposed IGP process is presented in HECO's Integrated Grid Planning Report, dated March 1, 2018.[248]

Under the "inside" single buyer model, the utility would continue to maintain its responsibilities under the PUC's applicable planning process, and may also have additional responsibilities for ring-fencing these functions. In the case of the "outside" single buyer model, the utility would relinquish these responsibilities and would solely seek to facilitate information sharing with the external single buyer entity.

The IRP process included an Independent Entity, which is a private party that provides advisory services, monitoring and reporting, facilitates public participation and input, and may offer to informally mediate disputes.[249] The IRP Framework required this Independent Entity to have no conflicts of interests and to be impartial. [250] Moreover, the Independent Entity is selected by the PUC and reported directly to the PUC. Under a single buyer, the Independent Entity could serve a broader role in the planning process, ensuring that the information submitted to the single buyer from the utility is both accurate and complete, managing confidentiality concerns, and other oversight provisions, in addition to the roles outlined above.

Both single buyer models would require significant alterations to the roles of the utility in the planning process, but neither are necessarily legally infeasible. In the case of the "inside" single buyer, the additional responsibilities for alterations to the utility's role include ring-fencing, which would largely mirror the ring-fencing procedures in the preceding section on procurement. In the case of the "outside" single buyer approach, the role includes greater information facilitation and responsiveness to single buyer requests, and relinquishment of the utility's previous responsibilities.

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[247] Docket No. 2009-0108, "Instituting a Proceeding to Investigate Proposed Amendments To the Framework for Integrated Resource Planning," Decision and Order, Exhibit A, issued March 14, 2011.

Also see Docket No. 2014-0183, "Instituting a Proceeding to Review the Power Supply Improvement Plans for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited." Decision and Order No. 23696; Order No. 32055 at 87-93; In re Hawaii Elec.Light Co., Docket No. 2012-0212; Decision and Order No. 31758, filed on December 20, 2013, at 113-121.

[248] *See*, Docket No. 2018-0165, Hawaiian Electric Companies' Integrated Grid Planning Report, filed on July 13, 2018.

[249] See Framework for Integrated Resource Planning, at 5-7.

[250] Note that the PUC reaffirmed the suspension of the IRP Framework requirements so it remains to be determined if similar requirements will be imposed in the PUC's planning process in the future. *See*, Order 35569, at 80.

6 Risk Analysis Methodology

This chapter assesses and compares the various sources of risk that present utilities are operating under each of the ownership models discussed above.

Each utility model was assigned a risk impact and likelihood rating during this exercise. Both the potential impact of the risk category and the risk likelihood (rating) were evaluated in tandem to assess the overall risk to the utility for each category. This analysis does not attempt to score the total overall risk of each utility model, but instead identify areas in which a particular utility ownership model may have comparatively higher or lower degrees of risk than another.

6.1 Methodology

The project team has identified four utility ownership models—IOU, co-op, single buyer outside of the utility, and internal utility single buyer—for additional analysis, including this assessment of risks associated with the different models. Each model was assessed against a set of 24 risk factors relating to a series of financial, business, macroeconomic, operational, and governance factors.

Generally, risks for the IOU and Cooperative model were assessed for a scenario in which the ownership model under consideration applied to all or a significant portion of the state's utility sector. In the case of the single buyer, risks were assessed for the legacy utility that would transition into a single buyer, as well as the single buyer entity itself. It is assumed here that the legacy utility in a single buyer scenario would be an IOU, though many of the conclusions would apply to settings in which the legacy utility was another organizational form. Therefore, the risk analysis for the two variants of the single buyer model only diverged from the risk analysis for the IOU model in cases in which the presence of the single buyer impacted the level of risk borne by the legacy utility.

For each ownership model, all risk factors were assigned a qualitative risk rating and impact rating. The risk rating reflects the relative *likelihood* that the risk factor will take place (i.e., the likelihood that the utility will default on its debt), while the impact rating reflects the relative *magnitude* the outcome would have on the utility if it took place (i.e., how impactful the credit default would be to the utility). The impact rating is the same for each risk factor across all three models.

The qualitative risk and impact rating schemes have five tiers: low, low-medium, medium, medium-high, and high. In the case where risk factors are unknown for a utility ownership model, either due to the novelty of the model or a lack of historic examples to provide evidence of risk, the risk factor was flagged for uncertainty. In cases where there is not an available basis on which to develop a risk rating, or where a rating must be established as baseline for comparison to other utility models, a default risk level of "medium" was applied.

In some cases, but not all, the risks described below can be mitigated with various strategies. For each risk category, we describe who is bearing the respective risk, and what can be done by different stakeholder groups (e.g., ratepayers, utility, regulators) to mitigate that risk. The final results are illustrated in an accompanying matrix in Microsoft Excel.

6.2 Factor Results and Discussion

6.2.1 Financial Risk

This section assesses financial risks including credit risk, accounting risk, cash flow risk, financial governance and policy risk, capital structure and asset protection, and liquidity risk. These risks primarily impact utility owners, such as shareholders in the case of an IOU and member-owners in the case of a Cooperative.

6.2.2 Credit Risk

Potential Impact: *High*
Potential Risk: *Investor-Owned: Medium*
Cooperative: Low
Single Buyer outside of the Utility: Low-Medium
Single Buyer within Utility: Low-Medium

Credit risk is defined as the risk of default on a debt that may arise from a borrower failing to make required payments. Credit risk is scored through credit ratings, which assesses an issue or issuer's creditworthiness. There are several credit rating agencies, including Moody's, Standard and Poor's, and Fitch, all of which use letter designations such as A, B, C. This assessment uses Standard and Poor's (S&P) credit rating scheme. S&P ratings range from prime investments (AAA) to defaulting investments (D), with many levels in between. Healthy investment grades range from AAA to BBB-.

In a 2014 direct comparison of IOU and Cooperative credit ratings, S&P provided a rating of A to A-, or Upper Medium Grade, for over 75% of electric Cooperatives, while assessing a credit rating between BBB+ to BB, or Lower Medium Grade to Speculative Grade, for roughly 70% of IOUs.[251] Looking at updated data from the first quarter of 2017, the distribution of IOU credit ratings has not substantively changed, with 67% of evaluated utilities receiving a rating of BBB+ or lower.[252] Based on this comparison, and assuming that an IOU and co-op on Hawaii would perform similarly to the national averages, we assign IOUs a medium credit risk, and Cooperatives a low credit risk.

Our analysis finds little reason to believe that co-ops in Hawaii would be unable to meet the predominant trend of creditworthiness exhibited more broadly by co-ops in the United States. In the specific case of Hawaii, while there is no credit rating for KIUC, KIUC has been successful in

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[251] Standard & Poor's and McGraw Hill Financial, 2014, Hot Topics in Public Power & Electric Cooperatives, https://www.spratings.com/documents/20184/86990/PubPower_ElCo-op_Slides_Boston_6_3_14/962095ae-3839-44dc-99b5-3ac9c4e662f4

[252] Edison Electric Institute, 2017, Electric Utility Industry Financial Data and Trend Analysis, 2017 Q1 Financial Updates.
http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/QtrlyFinancialUpdates/Pages/default.aspx

transforming its nearly entirely leveraged capital structure to a significant portion of equity. HEI's credit rating in 2016 ranged from BBB+ to BBB, which is in alignment with the general trend of credit ratings of IOUs more broadly.

In the case of a single buyer system, an assessment of creditworthiness should consider all parts of the system: the single buyer itself, the utility (which is assumed to continue to be an IOU), and the IPPs selling electricity to the single buyer. The credit risk of the utility is assumed to stay in line with national trends for IOU creditworthiness. In a system with robust competition, it is plausible that only the most creditworthy IPPs will be able to sign competitive PPA agreements with the single buyer. Therefore, credit risk of the IPPs is likely to be naturally low and maintained that way through the competitive market. The credit risk of the single buyer itself is difficult to predict as there are no examples to draw from in the United States. However, from 2012 to 2015, the Ontario Power Authority, a single buyer utility in Ontario, Canada, had a credit rating of AA+ to AA.[253] If the single buyer is a non-profit, the entity could also able to finance debt using low interest rates, which may also result in higher grade credit ratings. Due to a combination of these factors, both single buyers were assessed to have low-medium credit risks.

The impact of credit risk is defined as high for all three utility models, given the strong impact of defaulting and the post-default financing challenges. As a utility's credit rating drops, it becomes more difficult and costly to acquire capital, and the credit rating can spiral downward if not properly managed. One archetypal example of utility credit risk is that of the Puerto Rico Electric Power Authority (PREPA), which has held a very high debt-to-equity ratio (DER) for several years. In response to a declining credit rating, Citigroup severely restricted PREPA's line of credit for fuel purchases in 2014. PREPA did not have sufficient cash to pay for fuel from Petrobras, its primary oil supplier, forcing the utility to finance more debt through other mechanisms, further exacerbating its credit risk. PREPA is now at risk of bankruptcy and is seeking support from the U.S. government.

Across all models, credit risk could be mitigated by ensuring that utilities adhere to sound financial management practices, observe reasonable debt-to-equity ratios, and maintain the profitability and cash flows needed to make regular payments on debts. While it is assumed that utilities across all three ownership models will be able to meet these standards, credit risk cannot completely be eliminated, particularly as some factors (such as the risk of grid defection) lie outside of the utility's direct control.

6.2.3 Accounting Risk

Potential Impact: *Medium*
Potential Risk: *Investor-Owned: Low-Medium*
Cooperative: Low-Medium
Single Buyer outside of the Utility: Low-Medium
Single Buyer within Utility: Low-Medium

[253] Note that the original credit ratings come from Moody's (not S&P). The Moody's ratings were Aa1 to Aa2, equivalent to S&P's AA+ to AA.

While accounting risk is occasionally defined in different ways, for the purposes of this assessment, accounting risk is the extent to which the financial statements of a utility can be affected by differences in accounting method, which could lead to increased financial risk for utilities and their customers.

Generally, the project team does not find evidence that would support a significant difference in accounting methodologies across utility ownership models. The project team expects that any regulated utility (which, in Hawaii, currently includes both investor-owned and Cooperative entities) would be subject to adequate safeguards to ensure appropriate accounting practices. In any of these ownership models, utilities would also be subject to additional scrutiny. As a publicly traded entity, HEI currently prepares and submits Form 10-K financial statements that must conform with the US generally accepted accounting principles (GAAP).[254] A similar check on accounting standards is in place for Cooperatives that borrow from the US Rural Utilities Service (which is the case for KIUC and is assumed to true of any future Cooperatives in Hawaii), who must meet certain standards of the Financial Accounting Standards Board that provide additional accounting regulation.[255] It is assumed that the presence of a single buyer, whether independent or internal to a utility, would not substantively change the accounting practices of the underlying utility. It is assumed that these checks are generally adequate across all utility ownership models, and each model is assessed as a low-medium accounting risk.

The impact of accounting risk to utility customers is considered medium, as improper accounting practices could lead to substantial financial issues for utilities and their customers.

To reduce the risk of accounting risk, utilities can undergo a third-party audit of accounting processes and results to ensure that the work is being done efficiently, without errors, and using the most updated methods and software. Additionally, regulatory oversight from the Hawaii PUC and regulatory requirements such as those provided by the RUS provide a means of mitigating this risk.

6.2.4 Cash Flow Risk

Potential Impact: *High*
Potential Risk: *Investor-Owned: Low-Medium*
Cooperative: Low
Single Buyer outside of the Utility: Low-Medium
Single Buyer within Utility: Low-Medium

Cash flow risk is the risk that a utility's available cash will not be sufficient to meet its financial obligations. Cash flow risk is also relevant to counterparty contracts, which, in the case of utilities, are electricity contracts. The impact of cash flow risk is high across all four models because cash

[254] HEI 2016 Fiscal Year Form 10K

[255] For more information, see the USDA Rural Utilities Service Accounting Regulations Documentation here: https://www.rd.usda.gov/publications/regulations-guidelines/rural-utilities-service-accounting

flow balance impacts profitability and the utility's ability to pay off debt, which then impacts creditworthiness. One example of how cash flow risk significantly impacted a utility is that of Pacific Gas & Electric (PG&E) during the California Energy Crisis of the late 1990s. A combination of escalating retail electricity prices and retail price caps restricting cost recovery caused PG&E to have to file for bankruptcy in 2001.

The Cooperative model has a lower cash flow risk than the other models considered. One reason for this, or an advantage of the co-op model for this risk category, is that co-ops, unlike IOUs, are eligible to receive reimbursements through FEMA's Public Assistance Grant Program for natural disasters such as hurricanes and lava flows that would otherwise create a substantial financial burden on the cooperative.[256] However, the fundamental factors affecting the likelihood of cash flow risk are not expected to differ dramatically across the other ownership models, as operational and investment needs would be similar regardless of how the utility is owned. While the PG&E case demonstrates that there are cases of inadequate utility cash flows, this is assessed as a low-medium risk for any regulated utility in Hawaii because the state has cost-of-service regulations.[257] This regulation provides a reasonable assurance that the utility will be able to promptly collect revenues that recover costs and maintain cashflow adequacy. Depending on the nature of the formation of the single buyer, it could either act primarily as a broker between parties or be the direct counterparty in power purchase agreements with generators, in which case a reliable source of single buyer funding would be needed to ensure cash flow adequacy. In this analysis, it is assumed that the single buyer would act primarily as a broker between entities, and so this is not considered to be an impactful factor for cash flow risk.

Across all utility models, cash flow risk could be mitigated by the utility by implementing sound financial practices, but as highlighted in the PG&E example, some forces (such as broad regulatory environments) are outside the control of the utility, so this risk cannot be completely eliminated.

6.2.5 Financial Governance and Policy Risk

Potential Impact: *Medium*
Potential Risk: *Investor-Owned: Medium*
Cooperative: Medium
Single Buyer outside of the Utility: Medium
Single Buyer within Utility: Medium

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[256] 42 U.S.C. § 51212 et seq.; Texas Cooperative Action Network, "Issues: FEMA," accessed Dec. 17, 2018, available at http://www.texasaction.coop/content.aspx?page=fema. Eligible applicants for FEMA's Public Assistance Program include states, federally recognized tribal governments, U.S. territories, and certain private nonprofits. FEMA, "FEMA grants $1.28 million for power-system repair in four Texas counties," accessed Dec. 17, 2018, available at https://www.fema.gov/news-release/2018/11/27/fema-grants-128-million-power-system-repair-four-texas-counties.

[257] Note that alternatives to cost-of-service regulation (such as performance-based regulation) are addressed in Task 2 of this project.

Financial governance and policy risk is the risk to a utility's finances based on its level of financial oversight. In addition to oversight by state public utilities commissions, investor-owned utilities are subject to oversight from the US Securities Exchange Commission, and corporate finances are additionally scrutinized by key shareholders (though shareholder influence may have an adverse pressure of encouraging short-term returns over long-term profitability). Generally, Cooperative entities operate with less formal oversight, but as member-owned organizations, they may be influenced to prioritize long-term financial soundness. It is not clear that the addition of a single buyer entity would change the financial governance practices of the underlying utility.

While there are differences in the financial oversight that utilities are subjected to in the different models, it cannot be definitively stated how this would expose the utility models to differing levels of risk. Therefore, all utility models are assigned a risk level of medium.

The impact of this risk is also considered medium. If a utility does not have adequate and independent financial governance, its financial management quality may decline or stray from the priorities of the investors/members. Mitigation strategies to reduce this risk include continual participation in financial quality reviews by either stakeholders, SEC, or governing Board (for IOUs) or by the Cooperative utility members or the RUS (for co-ops). Cooperatives also can request technical assistance from the NRECA as an additional mitigation measure. For single buyers outside of the utility, a separate financial quality review team could be developed by the State to serve as the single buyer's financial governance entity.

6.2.6 Capital Structure and Asset Protection

Potential Impact: *High*
Potential Risk: *Investor-Owned: Medium*
Cooperative: Medium
Single Buyer outside of the Utility: Medium
Single Buyer within Utility: Medium

Capital structure is the way in which a utility finances its overall operations and growth by using different types of funds, such as bonds or long-term notes payable (debt) or stocks and earnings (equity). The mix of financing types is referred to as the utility's debt-to-equity (D/E) ratio. Usually a utility with a higher D/E ratio poses a greater risk to investors or lenders. Asset protection refers to a type of debt-to-equity planning intended to protect the utility's assets from creditor claims.

All else being equal, asset protection is a more significant concern for a utility that is highly leveraged or has many assets. Due in part to accessible, low-cost finance, Cooperatives typically undertake higher debt-to-equity ratios than investor-owned utilities.[258] However, the lower interest rates available to Cooperatives, coupled with the nature of Cooperative lending (where lenders are primary the federal government or specialized Cooperative lenders), can reasonably be expected to negate Cooperatives' exposure to additional risk in this area. Given these

[258] Robert L. Hahne and Gregory E. Aliff, *Accounting for Public Utilities*. (Revised 2017). LexisNexis.

countervailing pressures, IOU and Cooperative utilities are both assessed as a neutral (medium) risk rating. Both single buyer models are also assessed with a neutral risk rating, as the project team does not expect the inclusion of a single buyer to have an impact on this risk category.

The impact of capital structure and its relationship to asset protection is considered high given that creditor claims would ultimately affect the utility's credit risk, which could lead the utility to default. Capital structure risk could be mitigated by sound financial practices that maintain a reasonable D/E ratio, which keep utilities in good standing with lenders and creditors.

6.2.7 Liquidity Risk

Potential Impact: *Medium-High*
Potential Risk: *Investor-Owned: Medium-High*
Cooperative: Medium-High
Single Buyer outside of the Utility: Medium-High
Single Buyer within Utility: Medium-High

Liquidity risk is the risk that a given financial asset cannot be liquidated quickly enough in the market for emergency cash flow purposes. In this assessment, we do not consider the risk that a utility would find itself in a situation where liquidation is necessary (which is covered in other sections) but instead the ease with which a utility would be able to liquidate assets if forced to do so.

While there may be differences in how willing an IOU or a Cooperative would be to liquidate assets (it could be reasonably expected that a Cooperative may be less willing to sell assets due to the loss of community control), it is not expected that there would be a practical difference in the process of asset liquidation across the models in Hawaii, where both IOUs and Cooperatives are regulated by the state PUC and where a sale of any significant asset would be subject to regulatory approval. As regulatory approval of a sale is expected to be a lengthy endeavor, the liquidation risk for both the IOU and co-op models are rated as medium-high. It is not expected that the presence of a single buyer would change the ability of the underlying utility to liquidate assets, so these models are rated as medium-high as well.

The impact of liquidity risk is considered medium-high as the inability of a utility to liquidate assets in a time of financial need could lead to significant financial complications, or even default, on the part the utility. However, the likelihood of such a scenario occurring is expected to be rather low as utilities have other options besides liquidation to acquire capital in a time of need (i.e., loans; or in the case of IOUs, decreasing dividends, issuing more stock, etc.), which act a strong mitigating factors.

6.3 Business Risk

This section assesses business risks including industry risk, competitive risk, operating efficiency risk, management risk, ownership and governance risk, and profitability risk. These business risks primarily impact the utility, which could ultimately impact electricity ratepayers.

6.3.1 Industry Risk

Potential Impact: *High*
Potential Risk: *Investor-Owned: High*
Cooperative: High
Single Buyer outside of the Utility: High
Single Buyer within Utility: High

The uncertainty in the supply and demand of electricity is regarded as a key industry risk. For the purposes of this assessment, only demand risks are included in this discussion, as supply risks will be covered in the Commodity Price Risk section (4.4.7).

Demand risks in the case of a utility generally include the possibility of reduced electricity sales (due to economic trends, grid defection, or other factors), which would reduce the profitability of the utility over the long-term. We assess utility's demand risk and other industry risks to be generally consistent across ownership models and to not vary significantly with the inclusion of a single buyer entity. While it may be possible that the risk of grid defection could differ across models (for example, if Cooperative owner-members were less likely to defect from a utility that they owned a share in), there is not empirical data upon which to base such an assertion, so we assign the same risk level to all utility models. We assess this risk as high in Hawaii for all utilities, given that the state's high electricity rates create incentives for the customer to pursue technologies that allow for grid defection.[259]

The impact of industry risk is also assessed to be high given that widespread demand reduction would greatly impact cash flow and general utility finances. While there are some mitigation strategies available, such as new business models that encourage utility-customer collaboration on distributed generation, these strategies are not completely adequate, particularly in a market setting such as Hawaii's with high electricity rates.

6.3.2 Competitive Risk

Potential Impact: *High*
Potential Risk: *Investor-Owned: Medium*
Cooperative: Low-Medium
Single Buyer outside of the Utility: Low-Medium
Single Buyer within Utility: Low-Medium

Competitive risk is the probability of decline in a utility's competitiveness amongst other electric entities. In this assessment, we primarily consider the risk and impact of newly emerging distribution utilities offering competing service to retail customers, rather than the risk and

[259] For a discussion of the economics of solar and storage technologies that make grid defection a higher risk in Hawaii, see for example Bronski et al., *The Economics of Grid Defection* (2014). Available at: https://rmi.org/insights/reports/economics-grid-defection/

impact of increased competition in electricity generation (which is, in fact, a desired effect of the single buyer model, for example).

While competitive risk is generally quite low in the electric utility sector as utilities are typically granted exclusive franchises to operate in their jurisdictions with direct competition from other distribution utilities, Hawaii's utilities are operative with non-exclusive franchise agreements that theoretically allow for distribution competition.[260] For this reason, there is some exposure to competition for the existing utilities in Hawaii.

There is currently no distribution or retail service competition in Hawaii. However, there have been discussions about the development of a "community micro-grid" in at least one community on the Big Island, with several business models under consideration that include both operation as an Independent Power Producer that supplies to HELCO, and an option that would leverage HELCO's non-exclusive franchise to offer retail service to local energy users.[261]

Based on the practical possibility of retail competition in Hawaii, the project team rates the IOU model as having a medium level of risk. We assess this risk to be somewhat lower in the Cooperative model and the single buyer models. In the case of the Cooperative model, we assume that direct community control over a utility would decrease the risk that a competitive distribution entity would emerge, thereby assigning a low-medium level of risk. In the case of a single buyer, we determine that increased levels of generation investment would make it more likely that potential competitors would opt for an IPP business model rather than a competitive distribution business model.

To entities generating electricity, the impact of competition risk would be significant, as it would impact the profit of the utility and require an assessment of operations and possible revision of electricity rates. A true distribution and retail competitor would present a high risk for Hawaii's utilities and would threaten to reduce utility revenues and cause a variety of associated financial difficulties. Utilities can act to mitigate the competitive risk by ensuring a high quality of customer service and responsiveness to customer and stakeholder concerns that limit the opportunity for competitive retail service. Alternately, if deemed appropriate, this risk could be completely mitigated by states regulators and policymakers, who could recategorize Hawaii's electric utility franchises to be on an exclusive and non-competitive basis.

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[260] See the regulatory proceedings for the NextEra merger (Applicants' Response to LOL-IR-38, Docket No. 2015-022).

[261] The project referred to is Paniolo Power, a project of Park Ranch in Waimea. For more information on this project, see: Utility Dive, *Microgrid on the Big Island* (2014). Available at: http://paniolopower.com/wp-content/uploads/Parker-Ranch-Case-Study.pdf; and Dartmouth Tuck School of Business, *Parker Ranch: Hawaii at a Crossroads* (2015). Available at: http://councilonbusinessandsociety.com/images/uploads/parker_ranch_case.pdf

6.3.3 Operating Efficiency Risk

Potential Impact: *Medium*
Potential Risk: *Investor-Owned: Medium-High*
Cooperative: Low-Medium
Single Buyer outside of the Utility: Medium
Single Buyer within Utility: Medium

Operating efficiency is defined as the ratio between the return gained from running the utility and the resources required to run a utility. A higher operating efficiency leads to a more successful utility. Ultimately, the costs of inefficient operations are borne by the customer because they are passed down through rate structures.

In Hawaii's current utility sector, cost of service regulation creates opportunities (or at least the perception of opportunities) for operational inefficiency, as the utility's rate of return is generally stable regardless of fluctuations in operational costs. Given the ownership structures of IOUs and Cooperative utilities, Cooperatives theoretically have a greater incentive than IOUs to achieve higher levels of operational efficiency, as the cost of any inefficient operations or investment would be borne by member-owners. Conversely, in an IOU setting utility shareholders would benefit from increased utility costs, assuming these could be included in the utility's rate base and recovered from ratepayers, though this is mitigated by regulatory scrutiny provided by the PUC. While it is possible that Cooperatives utilities may experience comparative decreases in operational efficiency for other reasons, we generally assess the efficiency risk of the Cooperative model to be lower than that of an IOU due to the incentives provided by ownership structure.

The single buyer models could also provide a partial solution to (real or perceived) issues of ownership incentives and operational efficiency in the IOU mode through market forces. Because of the increased levels of generation competition provided through the single buyer models, generators would be incentivized to keep costs as low as possible, thereby increasing operational efficiency within generation assets. Assuming adequacy in the ring-fencing procedures established in a utility-based single buyer model, we do not assess there to be a notable difference in operational efficiency risk for internal versus single buyers outside of the utility, therefore both are assigned a low risk.

The potential impacts of operational efficiency are rated as medium. While (under the cost of service regulation and assuming the incorporation of costs into the utility rate base) the utility does not bear these impacts directly, these impacts are borne by ratepayers and may lead to indirect impacts on utilities (such as increased rates of grid defection).

Issues with ownership incentives and operational efficiency could also be achieved through adjustments to utility regulatory oversight rather than utility ownership. By adopting a

performance-based regulatory model (such as the RIIO[262] and RPI-X[263] models implemented in the United Kingdom), utility profit incentives could be better aligned with a variety of preferred performance metrics, which could include metrics of operational efficiency.

6.3.4 Management Risk

Potential Impact: *Medium*
Potential Risk: *Investor-Owned: Medium*
Cooperative: Medium-High
Single Buyer outside of the Utility: High
Single Buyer within Utility: Medium-High

Management risks are associated with ineffective, destructive, or underperforming management, which can negatively impact the utility's efficiency, profitability, and therefore credit rating. While there have been cases of positive and negative management practices in both IOU and co-op utility models, the project team assesses the Cooperative model as having slightly higher risk than the status quo utility model in Hawaii because an expanded Cooperative enterprise in Hawaii would face the challenge of recruiting adequate management to oversee the transition and manage the new utility, which is not applicable in the status quo. The IOU model is provided a default risk level of medium, with a slightly high risk assessed for Cooperatives.

A single buyer outside of the utility model would face a similar source of risk, as a new independent entity must be overseen by appropriate management, while an internal utility-based single buyer would presumably redirect existing management within the organization. However, both single buyer variants would face risks associated with being the first adopter of the single buyer model in the United States, with the associated lack of familiarity increasing the risk of ineffective management.

As a result, the status quo IOU model is assigned a baseline medium risk, medium-high levels of risk are assigned to the Cooperative model (due to recruiting needs) and the utility single buyer model (due to unfamiliarity with the single buyer mode), and the single buyer outside of the utility model is assigned a high management risk (due to the combination of these factors).

The impact of poor management is deemed as a medium risk since it is impactful yet reparable in the medium-term. Mitigation strategies to reduce this risk include, for example, recruitment practices that emphasize the selection of experience and quality managerial staff, regular internal and external employee evaluations, regular trainings of managerial staff.

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[262] In the RPI-X regulatory scheme, utilities that can achieve greater levels of operational efficiency are rewarded with higher rates of return.

[263] Under the RIIO framework the revenue that utilities are permitted to collect is tied to (among other factors) their progress towards achieved agreed-upon outputs in a number of operational areas.

6.3.5 Ownership and Governance Risk

Potential Impact: *High*
Potential Risk: *Investor-Owned: Medium*
Cooperative: Medium
Single Buyer outside of the Utility: Low-Medium
Single Buyer within Utility: Medium

There are various risks associated with the manner in which utilities are owned and governed by a utility. As noted above in the discussion of operating efficiency, shareholder ownership of IOUs could present a misalignment between shareholder and ratepayer priorities, presenting a source of risk. For Cooperatives, governance by a member-elected board ensures alignment with ratepayer priorities, but the potential for high turnover among board members can create risks associated with continuity, changes in strategic direction, or loss of institutional knowledge.

Cooperatives are governed by a board elected by the community to represent the community, so its decisions are generally aligned with the needs of the community ratepayers, and its risk is likely to be lower than that of IOUs. However, community governance also has a downside. In the first 15 years of operations, KIUC members elected 45 different individuals to its board of directors,[264] indicating potential challenges in maintaining consistency in organizational governance. Due to these countervailing pressures, both IOUs and Cooperatives are assessed a medium risk level.

As a utility-based single buyer would have the same ownership and governance as the incumbent utility, this is also assessed as having a medium level of risk. The single buyer outside of the utility model is assumed to carry a slightly lower level of risk, however, as the independence and impartiality of the appointed directors of the single buyer are considered to insulate the utility system somewhat from misaligned incentives and other sources of ownership and governance risk.

The impact of ownership and governance risk is deemed as a medium-high risk since it is both impactful and challenging to repair given the permanent role that shareholders have in the ownerships of IOUs and the elected nature of co-op boards. For similar reasons, this risk category is also difficult to mitigate. In the case of the single buyer within a utility, robust ring-fencing measures could reduce ownership and governance risk by limiting potential conflicts of interest between single buyer and utility operations.

6.3.6 Profitability Risk

Potential Impact: *Medium*
Potential Risk: *Investor-Owned: Low-Medium*
Cooperative: Low-Medium
Single Buyer outside of the Utility: Low-Medium

[264] Dennis Hollier, "Who Should Own Hawaiian Electric?" *Hawaii Business* (October 2015).

Single Buyer within Utility: Low-Medium

Profit risks are associated with a utility's net income. Because all utility models are regulated under cost-of-service in Hawaii, we expect minimal profitability risk for any utility model under current regulations. While there may be important differences in how utilities manage towards profit (i.e., an investor-owned utility may face pressures from investors for shorter-term profitability, while member-owned Cooperatives may consider longer-term community impacts), we do not assess a substantial difference in the risk of profitability for either model.

We also do not consider the addition of a single buyer to impact profitability risk for the transmission and distribution portions of a utility business. It is possible that a single buyer could reduce the profitability of utility-owned generation assets due to increased market competition and participation from independent power producers; but as this would be an intended consequence of the model, it is not assessed as a risk here.

The impact of profit risk is considered medium because utilities that have smaller profit margins have worse financial performance. This risk is on a gradient, as severe profit issues can lead to increased risk of bankruptcy. Profitability risk could be mitigated using sound financial practices and regular external evaluations of operating efficiency.

6.4 Macroeconomic Risk

This section assesses macroeconomic risks including sovereign credit rating and the U.S. interest rate. These risks primarily impact the utility investors (or shareholders, in the case of IOUs).

6.4.1 Sovereign Credit Rating and U.S. Interest Rate Risk

Potential Impact: *Medium-High*
Potential Risk: *Investor-Owned: Low-Medium*
Cooperative: Low-Medium
Single Buyer outside of the Utility: Low-Medium
Single Buyer within Utility: Low-Medium

The sovereign credit rating of a country gives investors insight into the level of risk associated with investing in a country or state and includes political risks. As sovereign credit rating and the US interest rate are directly related, we combine them for this discussion.

We generally assess the same level of risk to all utility models in this category, though we note that there may be some differences in how this impact is realized. As many Cooperatives borrow from the US Rural Utilities Service at a rate based on the US Treasury interest rate, the affordability of Cooperative finance is directly tied to these macroeconomic forces. However, as the impacts of changes in the US interest rate or sovereign credit rate have impacts throughout the US and global economy, we assume that the impact on the cost of financing would be similar under the other models as well. We assess this risk as low-medium, as the credit rating of the United States has historically been set at the highest levels by all three major ratings agencies, but was downgraded by Standard & Poor's from AAA to AA+ in 2011. We assess the impact to be

medium-high, as a change in the costs of finance could have considerable impacts on utility finances and ratepayer costs.

While there are some strategies that could be used to mitigate the risk of sovereign credit ratings and US interest rates (such as interest rate swaps), it is unlikely that any utility could completely insulate themselves from this risk.

6.5 Operational Risk

This section assesses operational risks associated with technology change, generation and transmission and distribution costs, reliability and grid resilience, labor availability and skill, environmental risks, asset quality, commodity price, and financial market volatility.

6.5.1 Technology Change

Potential Impact: *High*
Potential Risk: *Investor-Owned: Medium-High*
Cooperative: Medium-High
Single Buyer outside of the Utility: Medium
Single Buyer within Utility: Medium

Technology change risk refers to changing or updating current generation, transmission, or distribution technologies to novel or state-of-the-art technologies. Such technologies could include renewable energy generation, energy storage, micro-grids, demand response, and advanced metering infrastructure, among others. The challenges and risks inherent in these technologies will be and are being felt by utilities across the country but can reasonably be expected to be particularly high in Hawaii given the state's small and disaggregated electric grids, high electricity prices, and ambitious renewable energy targets.

Generally, we do not expect the challenges faced by new technologies to differ substantially between IOU and Cooperative utilities and feel that there is a sizeable amount of risk regardless of the utility model. However, under the single buyer model, we expect that non-utility actors that can offer superior solutions that utilize emerging technologies may find an easier and quicker path to bringing these technologies to the market. Under both the status quo (IOU) model and the Cooperative model, technology solutions offered by the utilities themselves may be more likely to be implemented due to the nature of the resource-planning process, which may not be the technologies best equipped to address Hawaii's energy needs. Considering this risk from the perspective of Hawaii residents and ratepayers, the single buyer models may, therefore, lower the risks posed by new technologies.

The impact of technology change risk to a Hawaii utility is classified as high, given that Hawaii has aggressive renewable energy goals that need to be met in a short amount of time. Technology change risk could be mitigated by a series of approaches such as implementing pilot programs that utilize experimental technology, collaboration with government and key stakeholders on public-private partnerships to deploy cutting-edge technologies, and similar approaches. However, we do not expect that technology risk can be completely mitigated.

6.5.2 Cost of Generation, Transmission, and Distribution

Potential Impact: *Medium*
Potential Risk: *Investor-Owned: Medium*
Cooperative: Medium
Single Buyer outside of the Utility: Medium
Single Buyer within Utility: Medium

As a utility, there are risks associated with future costs of developing and maintaining generation, transmission, and distribution infrastructure. We have no reason to expect that costs of infrastructure and maintenance to vary across utility ownership models (it is possible that utilities will have different levels of effectiveness in their operation of these assets, but this is covered in the section on operating efficiency above). It is worth noting that, in the single buyer model, it is possible that a greater share of generation (and thus a greater share of generation capital and maintenance costs) would come from non-utility actors than in the other models. However, this would not change the risk level to the system as a whole but would only shift some portion of generation costs and risks (as well as benefits) from the utility to IPPs. For this reason, all utility models are assigned the same level of risk in this category.

The impact of generation, transmission, and distribution cost risk is categorized as medium given the risks of maintaining assets that are critical to the functionality of the utility and reparable with sufficient attention and resources. These risks could be mitigated by the utility via regular maintenance of infrastructure so that significantly costly repairs and updates are prevented before they arise.

6.5.3 Reliability and Grid Resilience

Potential Impact: *High*
Potential Risk: *Investor-Owned: Medium*
Cooperative: Medium
Single Buyer outside of the Utility: Medium
Single Buyer within Utility: Medium

As a utility, there are high-impact risks associated with the reliability and grid resilience of the electricity grid due to hurricanes, tsunamis, and other natural disasters.

In Hawaii, grid resiliency is a particularly significant concern given the state's geographic isolation and the presence of the US Pacific Command (PACOM) on the island. PACOM stakeholders report a strong working relationship with the HECO companies, but this does not mean that there could not be a similarly strong relationship with a Cooperative utility, or that a single buyer would complicate grid resiliency efforts.

At a national level, Cooperatives utilities do typically have higher average outage frequencies and durations than IOUs (as measured by national SAIDI and SAIFI averages).[265] However, a direct comparison cannot be fairly made as most Cooperative utilities serve rural areas with low population density, where electric grid redundancy is less feasible and utility crew response times are higher. As there has not been a single buyer implemented in the United States, we similarly cannot make a judgment on how grid reliability would be impacted under that model, though we expect that with proper collaboration on distribution network planning between the single buyer and the utility, there would be minimal impact.

Therefore, we have no reason to form a distinction between the four models in reliability and grid resilience risk and assess all models a medium risk.

The impact of poor grid resiliency and reliability is considered high risk because it has a significant impact on ratepayers and is difficult to repair in the short-term. These risks could be mitigated by adopting resiliency technologies and practices incrementally over time, conducting frequent tests of the system's reliability, developing a long-term resiliency strategy between the utility and the State, or conducting a study on the economic cost of grid outages.

6.5.4 Labor Availability and Skill

Potential Impact: *Medium*
Potential Risk: *Investor-Owned: Medium*
Cooperative: Medium-High
Single Buyer outside of the Utility: High
Single Buyer within Utility: Medium

As a utility, there are risks associated with the availability of skilled labor to perform the necessary functions of the company. In an area as geographically isolated as Hawaii, it can be challenging to identify and recruit staff with specialized skill sets, and so we generally rate utility models as having a medium level of baseline risk.

We do not believe employee compensation would have an impact on labor risk across the utility models. According to a report by the American Public Power Association, co-ops and IOUs offer comparable salaries to their employees of similar rank.[266] Based on this, we do not expect that the two utilities would face differences in their ability to recruit new staff.

However, one challenge that a new utility entity in Hawaii would incur is their ability to retain and transition legacy staff of the acquired incumbent utility – this challenge would apply to a new Cooperative utility as envisioned in this study. A single buyer outside of the utility model would encounter even greater challenges, as they would need to recruit qualified staff to carry

265 See http://grouper.ieee.org/groups/td/dist/sd/doc/2016-09-04%20APPA%20Public%20Power%20Reliability%20Update-Alex%20Hofmann.pdf

266 See http://c.ymcdn.com/sites/members.iamu.org/resource/resmgr/informer_2016/APPA_Pay_Report.pdf

out the functions of the single buyer. However, we expect that a utility-based singe buyer would simply reallocate existing utility staff.

Labor risk is classified as having a medium impact because having sufficient qualified staff is essential to the utility's operations, but that labor issues can be repaired relatively quickly through recruiting and staff training during onboarding. Labor risk can be somewhat mitigating by offering compensation packages that are competitive with the industry. However, given the limited labor pool in Hawaii and its distance from the mainland, this risk cannot be completely mitigated.

6.5.5 Environmental Risks

Potential Impact: *High*
Potential Risk: *Investor-Owned: Medium*
Cooperative: Medium
Single Buyer outside of the Utility: Medium
Single Buyer within Utility: Medium

We consider two categories of environmental risk: those associated with hurricanes, tsunamis, climate change, and other natural disasters, which could impact infrastructure; and the risks posed to the environment by the utility's operations, including air quality, water quality, and the treatment of toxic substances.[267]

Regarding the natural disasters, there are likely few differences across the four utility models, though more differences may arise based on the geographic presence of the utility model (i.e., single or multi-island). A multi-island utility may be able to respond to natural disasters more efficiently using resource-sharing across all the islands. If there are separate utilities on each Hawaiian island, any Cooperative arrangements between utilities on different islands to address disasters would mitigate some of this environmental risk. The likelihood of environmental risks is generally low, as the highest impact events happen less frequently than low-impact events; however, the effects of climate change are increasing the frequency of the high-impact events over time and are expected to continue increasing in frequency into the distant future.

Regarding the treatment of the environment by utility operations, there are also likely few differences across the four utility models. All electricity generating facilities are regulated under the EPA[268] regardless of the utility model. The State renewable energy target is a significant mitigation strategy to reduce the environmental impact of utilities.

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267 These three environmental considerations are those on which HEI and other electric utilities are subject to regulation. For more information, please see:
http://www.hei.com/Cache/1500096268.PDF?O=PDF&T=&Y=&D=&FID=1500096268&iid=1031123

268 See the U.S. Environmental Protection Agency NAICS 2211 regulation here: https://www.epa.gov/regulatory-information-sector/electric-power-generation-transmission-and-distribution-naics-2211

Because of the similarity across all models for both environmental impacts and risk to infrastructure from natural disasters, the likelihood of environmental risk of all four utility models is considered medium.

The impact of environmental risks is classified as high, given the potential destruction that can come from large natural disasters and the time and resources required to recover from them. Though natural disasters cannot be eradicated or prevented, the severity of their impact can be reduced via planning, preparedness, recovery, and adaptation measures.

6.5.6 Asset Quality

Potential Impact: *Low-Medium*
Potential Risk: *Investor-Owned: Low-Medium*
Cooperative: Low-Medium
Single Buyer outside of the Utility: Low
Single Buyer within Utility: Low

Asset quality risk reflects differences in how the utility models upkeep their assets and infrastructure, and how those risks are transferred to ratepayers. We do not believe there is a substantial reason to believe that IOUs or co-ops are more likely to experience asset quality risk. Because utilities in both models would be able to recover maintenance costs (so long as they are deemed reasonable by the state PUC and included in the ratebase), we project this risk as low-medium for co-ops and IOUs.

One potential advantage of the single buyer model is that increased competition in the generation sector would put increased pressure on the incumbent utility (as well as other power providers) to maintain a high level of asset quality for competitiveness reasons. Therefore, the two single buyer models were assigned a low asset quality risk.

Asset quality issues are considered to have a low-medium impact on utility operations and ratepayers; if operations and maintenance of generation or transmission are not done regularly, this could have a significant impact on utility profit. This risk can be mitigated with regular upkeep and updating of utility infrastructure assets.

6.5.7 Commodity Price

Potential Impact: *High*
Potential Risk: *Investor-Owned: High*
Cooperative: High
Single Buyer outside of the Utility: High
Single Buyer within Utility: High

Commodity price risk is the threat that a change in the price of a production input will adversely impact the production of the output. In the context of electric utilities in Hawaii, the price of oil the primary relevant metric.

The volatile price of oil is a major challenge for Hawaii's utilities and ratepayers, and we do not expect this challenge to be associated with a change in ownership. While a utility may act to insulate itself from high and variable oil prices by developing local renewable energy resources, we do not suggest that the tools available to the utility to do so, or the challenges that they would face in the process, are categorically greater or lesser across utility ownership models, and so we consider commodity price risk to be high for all four models.

Commodity price risk is classified as high impact given that high oil prices would significantly and directly impact ratepayers, yet those prices are uncontrollable. Over the past 20 years, oil prices have ranged from $14.42/barrel to $99.67/barrel, a difference nearing a factor of seven.[269] Oil price spikes would have a detrimental impact on ratepayers, as electricity rates are already very expensive – $0.2822/kWh residential rate in 2017 on Oahu[270] – compared to the U.S. Pacific Contiguous region average for that same time period – $0.1328/kWh.[271] This risk could be mitigated by investing more generation in non-fossil fuel based energy sources like solar and wind energy.

6.5.8 Financial Market Volatility

Potential Impact: *Medium*
Potential Risk: *Investor-Owned: Low-Medium*
Cooperative: Low-Medium
Single Buyer outside of the Utility: Low-Medium
Single Buyer within Utility: Low-Medium

Financial market volatility is the susceptibility to change in financial markets. All utility models are involved in financial markets in some capacity, and their costs of capital to pursue upgrades are dependent on the state of financial markets. As with any industry, utilities are also impacted by larger economic trends such as recessions.

Compared to other industries, however, electricity demand is somewhat inelastic, somewhat mitigating the risk for utilities. We rate this as a low-medium risk for utilities and do not project any reasons for a difference across utility models (all of which would be impacted by larger economic trends and volatility).

The impact of financial market volatility is classified as a medium risk. While financial market volatility cannot to be controlled or repaired by the utility itself, it could be mitigated by

269 See EIA reporting of U.S. crude oil prices: https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RWTC&f=A

270 See https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/average-price-of-electricity

271 See EIA Electricity Data Browser, 2017 annual Pacific Contiguous retail electricity rates: https://www.eia.gov/electricity/data/browser/#/topic/7?linechart=ELEC.PRICE.PCC-ALL.A

increasing a utility's reliance on equity compared to debt, among other approaches (though this may not be in line with a utility's overall financial strategy).

6.6 Governance Risk

This section assesses governance risks associated with regulation and the law. These risk factors impact the utility and ratepayers, though legal risk can also impact investors.

6.6.1 Regulatory Risk

Potential Impact: *High*
Potential Risk: *Investor-Owned: Medium-High*
Cooperative: Medium
Single Buyer outside of the Utility: Medium-High
Single Buyer within Utility: Medium-High

Regulatory risk is interpreted here as the risk of change in electricity rate regulation and its impact on the utility and its ratepayers. Changes in regulatory approaches can have significant impacts on the profitability and operations of a utility, as these govern the amount of revenue that utilities can collect from its from ratepayers and provide powerful incentives to the utility regarding the structure of their operations.

While regulatory approaches vary significantly from state to state, all IOUs in the United States are regulated by state regulatory commissions. Hawaii's existing Cooperative utility is regulated by the state public utility commission as well (whereas in most US states, Cooperatives are unregulated). However, in practice, Hawaii's PUC has not subjected the current electricity Cooperative to the same level of regulatory scrutiny as the state's IOU (for example, KIUC was not required to develop a Power Supply Improvement Plan). Therefore, IOUs are assigned a medium-high regulatory risk, while co-ops are assigned a medium risk to reflect the slightly lower level of regulation. We do not have reason to believe the addition of a single buyer to the system would impact regulatory risk, so both models are assigned the same risk as IOUs—medium-high.

Regulatory risks could be mitigated by taking steps within the state public utility commission to ensure that regulatory approaches are well-founded and in line with policy objectives. However, it is unlikely that the risks inherent in any regulatory approach could be fully mitigated. In the specific case of Cooperatives, the public utility commission could also opt to cease regulation of the utility, which would dramatically ease the utility's regulatory burden, but which could increase the utility's susceptibility to other categories of risk discussed in the analysis.

6.6.2 Legal Risk

Potential Impact: *High*
Potential Risk: *Investor-Owned: Medium*
Cooperative: Medium
Single Buyer outside of the Utility: Medium
Single Buyer within Utility: Medium

Legal risk describes the potential that a utility, its investors, and its ratepayers could be adversely impacted by new state energy laws. This could include legislative approaches as far-ranging as net metering regulations, renewable energy mandates, or utility restructuring.

Clearly, any form of utility could be dramatically impacted by new energy legal frameworks. Given the recent establishment of a 100% renewable portfolio standard for Hawaii in 2015, it is reasonable to expect that the risk that a utility could be dramatically impacted by energy laws in Hawaii is quite high. While it is true that, in many states, renewable portfolio standards (among other state energy laws) are restricted to investor-owned utilities, this is not the case in Hawaii, and so we do not rate the Cooperative model as having a lower risk than other utility models. Given the recent history of legislation with significant impact for utilities, we rate this as a medium risk for all utility models.

While there are no sure means of avoided the risks of wide-ranging energy legislation, these can be somewhat mitigated by carefully studying the impacts of potential legislative strategies.

6.7 Conclusion of Risk Analysis

Through this risk assessment exercise, the Project Team has determined that the risk associated with the four utility ownership models (IOUs, co-ops, single buyer outside of the utility, and internal single buyer within utility) is likely to differ within twelve of the twenty-four risk categories. The risk categories which are likely to differ across models include credit, accounting, competitive, operating efficiency, management, ownership and governance, technology change, generation/transmission/distribution cost, reliability, labor, asset quality, and regulatory risks.

Risk categories with the most variation across the utility models are management risk, ownership and governance risk, and operating efficiency risk. Mitigation strategies exist to reduce management and operating efficiency risks; however, ownership and governance risk is nearly impossible to mitigate, given that it is tied to the ownership structure of the utility models. The two single buyer models perform better than IOUs and co-ops in operating efficiency, while the single buyer outside of the utility performs best in ownership and governance risk. IOUs perform the best of all models for management risk. Of the twelve categories with variations in risk ratings, the four categories with the highest potential impact to the utility are credit, competitive, technology change, and regulatory risks. Both the potential impact of the risk category and the risk likelihood (rating) were evaluated in tandem to assess the overall risk to the utility for each category.

IOUs have a uniquely high risk in credit rating, competition, and operating efficiency risks, but have a uniquely lower relative management risk compared to the other models. All four models bear high risk in the categories of industry and competitive risk. The only model that has a high risk outside those two categories is that of the single buyer outside of the utility, which also has a high risk for management risk and labor risk. The internal single buyer model has a lower overall risk than the single buyer outside of the utility, which has higher risk associated with ownership/governance, management, and labor. Finally, Cooperatives have the least risk amongst the four utility models and have uniquely low risk ratings for credit risk and operating efficiency, which have a high and medium impact rating respectively. Cooperatives perform well

in most financial and business risk categories, but have moderate risk associated with management, technology change, and labor.

Figure 24. Summary of Risks for Each Model

Category	Risk	Impact Rating	Risk Rating			
			IOU	Coop	Outside Single Buyer	Utility Single Buyer
Financial Risks	Credit	H	M	L	LM	LM
	Accounting	M	LM	LM	LM	LM
	Cash Flow	H	LM	LM	LM	LM
	Financial Governance/Policy	M	M	M	M	M
	Capital Structure/Asset Protection	H	M	M	M	M
	Liquidity	MH	MH	MH	MH	MH
Business Risks	Industry	H	H	H	H	H
	Competitive	H	M	LM	LM	LM
	Operating Efficiency	M	MH	LM	M	M
	Management	M	M	MH	H	MH
	Ownership/Governance	H	M	M	LM	M
	Profitability	M	LM	LM	LM	LM
Macro-Economic	Sovereign Credit Rating/U.S. Interest Rate	MH	LM	LM	LM	LM
Operational Risks	Technology Change	H	MH	MH	M	M
	Generation/T&D Costs	M	M	M	M	M
	Reliability and Grid Resilience	H	M	M	M	M
	Labor Availability/Skill	M	M	MH	H	M
	Environmental	H	M	M	M	M
	Asset Quality	LM	LM	LM	L	L
	Commodity Price	H	H	H	H	H
	Financial Market Volatility	M	LM	LM	LM	LM
Governance Risks	Regulatory	H	MH	M	MH	MH
	Legal	H	M	M	M	M

Legend Notes:
H – High Risk/Impact
MH – Medium/High Risk/Impact
MH – Medium Risk/Impact
LM – Low/Medium Risk/Impact
L – Low Risk/Impact

Appendix A: Scope of work to which this deliverable responds

1.3.1 - Identification of various steps, timeline, and costs required to change from current ownership model to new models, including regulatory approvals.

CONTRACTOR shall identify the required steps and associated costs, along with a projected timeline, to change the ownership model and acquire the electric generation, transmission, and distribution plant (including substations) currently operated in each county, including all necessary approvals and/or permitting requirements

CONTRACTOR shall provide its conclusions and all work related to identifying the steps that need to occur to change from the current regulated private utility ownership to each recommended ownership option, including providing an assessment of acquisition costs and valuations of the current electric grid and utility assets and analyzing the costs to the utilities and ratepayers of achieving Hawaii's 100% renewable goal, and compare these to utilities' current plans. CONTRACTOR shall deliver a cost assessment by year over the identified timeline, provide estimates of necessary legal costs, identify regulatory approvals necessary, and identify permitting requirements needed. Findings shall be summarized in a user-friendly narrative detailing the steps and tying them to the costs (or cost ranges) required for each step.

1.3.2 - Identification of legal changes needed to implement the proposed utility legal framework options.

CONTRACTOR shall conduct a detailed analysis to determine the legal framework of the ownership models, list Hawaii laws and regulations that are required, and identify the changes to existing statute and regulations that are required and if any proceedings might be necessary. The analysis shall also estimate costs, timing, and strategies for navigating through each proceeding

CONTRACTOR shall provide its conclusions and all work related to the legal changes needed to implement the recommended utility ownership options. Work shall include: (1) identifying a series of ownership legality categories and (a) examining them against Hawaiian legislation and statutes; and (b) benchmarking them against ownership statutes and documentation governing utility legal structures under similar utility ownership models as the model(s) proposed for Hawaii; and (2) identifying gaps in the current legislation and identifying where changes are needed. Work shall use targeted interviews with relevant jurisdictions to determine the level of difficulty of these changes, political considerations, historical drivers and barriers to change, necessary analyses to support such legal changes, navigation strategies, and timing and cost estimates. This work shall be completed in partnership with legal counsel experienced with Hawaii laws and regulations related to energy.

1.3.3 - Identification of risk for each ownership model, analysis of each risk, and assessment of the overall risk profile for each ownership option.

CONTRACTOR shall identify the known or potential financial and operational risks and the bearer of those risks (e.g. ratepayers, utility shareholders, taxpayers) under each ownership model.

CONTRACTOR shall provide its conclusions and all work related to identifying risks for each ownership model, assessing the following risk categories: financial risks (includes credit risk, accounting risk, cash flow adequacy, financial governance/policy risk, capital structure/asset protection, and liquidity/short term factors), business risk (includes industry risk, competitive position/competition, operating efficiency, management risk, ownership/governance, and profitability (as applicable)), country/macroeconomic risk (includes sovereign credit ratings, and U.S. interest rate risk), operational risks (includes technology change, generation/T&D costs, reliability/grid resilience, labor availability/skill, environmental impacts, asset quality, commodity price risk, financial market volatility risk), and governance risks (includes regulatory risks, and legal risk). CONTRACTOR shall provide an analysis for each of these types of risk, estimating the probability of each risk, and its potential severity or impact, and considering the adequacy of typical risk mitigations. CONTRACTOR shall assess the overall risk profile for each ownership model and present the analysis in a comparable way.

Appendix B: List of works consulted

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Assessment of the impact of the regulatory change to the staffing of relevant State agencies

prepared for Hawaii DBEDT by London Economics International LLC

October 11, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals; this document is one of several working papers associated with that engagement. This memo, which corresponds to Task 2.3.4, we evaluate the impact of the recommended regulatory change structure to the staffing needs of relevant state agencies (such as Public Utilities Commission ("PUC"), and the Division of Consumer Advocacy ("DCA")). Based on our analysis, we conclude that the implementation of the Outcomes-based Performance-Based Regulation ("PBR") model may result in a change (which could be higher or lower) in the number of staff. However, moving towards the Conventional PBR with Light Hawaii Electricity Administrator ("HERA") model or the Hybrid model might increase staffing needs. Moreover, the staff's expertise, as well as the organizational breakdowns (divisions), are very similar amongst the different potential regulatory models. The goals and complexity of energy policies, too, have impacts on the management and staffing needs of these agencies.

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List of acronyms

AUC	Alberta Utilities Commission
CUB	Citizens Utility Board
DBEDT	Hawaii Department of Business Economic Development and Tourism
DBF	Department of Budget & Finance
DCA	Division of Consumer Advocacy
DCCA	Department of Commerce and Consumer Affairs
DERs	Distributed energy resources
DPS	Department of Public Service
DSPP	Distributed System Platform Provider
EIMA	Energy Infrastructure Modernization Act
FTE	Full-time equivalent
GEMA	Gas and Electricity Markets Authority
HECO	Hawaiian Electric Company
HELCO	Hawaii Electric Light Company
IGO	Integrated Grid Operator
IPART	Independent Pricing and Regional Tribunal
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company
NASUCA	National Association of State Utility Consumer Advocates
NER	National Electricity Rules
NSW	New South Wales
NY PSC	New York Public Service Commission
OCC	Office of Consumer Counsel
OEB	Ontario Energy Board
Ofgem	Office of Gas and Electricity Markets
PPAs	Power purchase agreements
PUC	Public Utilities Commission
REV	Reforming the Energy Vision
RIIO	Revenue = Incentives + Innovation + Outputs
RPS	Renewable Portfolio Standards
RRFE	Renewed Regulatory Framework for Electricity
ST	Suruhanjaya Tenaga
TNB	Tenaga Nasional Berhad
UCA	Office of the Utilities Consumer Advocate
UCB	Utility Consumers' Board
UK	United Kingdom

1 Executive Summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which corresponds to Tasks 2.3.4 in the project scope of work, provides an estimate of the potential impacts a change in the regulatory model may have on the expertise and staffing requirements of related State agencies. Although several state agencies interact with the electric utilities, we are focusing this paper on similar agencies such as the Hawaii Public Utilities Commission ("PUC") and the Division of Consumer Advocacy ("DCA") in Hawaii. We have reviewed standard practices in other jurisdictions with the three potential regulatory models that were recommended in Task 2.2.6 and provided an assessment of the impact of the regulatory change to the staffing of relevant State agencies under each model.

As discussed in Task 2.2.6, the three recommended regulatory models for the City and County of Honolulu, County of Maui, and County of Hawaii include (i) Outcomes-based PBR, (ii) Conventional PBR with Light HERA, and (iii) the Hybrid model[1]. As discussed in previous working papers, the Hybrid model includes an Outcomes-based PBR, a Distributed System Platform Provider ("DSPP") and an Integrated Grid Operator ("IGO")).

Since these three recommended models are relatively innovative, only a few jurisdictions have some elements of these recommended models in their current regulatory framework, so the Project Team selected some jurisdictions for further review of staffing in relevant agencies. The United Kingdom (the "UK") and Ontario were chosen to represent the Outcomes-based PBR model. Illinois, Alberta, and New South Wales were selected to represent the Conventional PBR with Light HERA model.[2] Since no jurisdiction currently has the Hybrid model, we selected New York as an example since it is under the Reforming the Energy Vision ("REV") that have similar elements of Outcomes-based PBR as well as DSPP. New York also has an independent system operator. We compared the staffing numbers before and after the change of regulatory models to study the impact of the change on staffing relevant State agencies.

Our primary observations include the following:

- The jurisdiction (i.e., New York State) that is moving towards a Hybrid model has a higher staff-to-customers ratio in the PUC than jurisdictions with other regulatory models. This is because of the more complex regulatory framework under a Hybrid model that requires more technical staff to design and monitor the regime;

[1] As for the recommended regulatory models for the County of Kauai, the "Lighter PUC Regulation" model will obviously require fewer staff members in the Hawaii PUC. Detailed discussion on representative states that have lighter PUC regulation has been included in Section 5.3.2 Cooperative under Task 1.3.4.

[2] Since HERA does not exist in Hawaii and there is no similar entity in other jurisdictions, this section focuses on jurisdictions that implemented Conventional PBR only.

- Outcomes-based PBR-dominated and Conventional PBR-dominated jurisdictions, such as the UK, Ontario, Malaysia, Alberta, and New South Wales, have a lower staff-to-customers ratio in the PUC than the jurisdiction (i.e., New York State) with the Hybrid model;

- Currently, the Hawaii PUC has a significantly higher staff-to-customers ratio than the selected jurisdictions for the Outcomes-based PBR and Conventional PBR with Light HERA models (more than tripled), but lower than the representative jurisdiction for the Hybrid model;

- When implementing PBR mechanisms, the PUCs usually hire external consultants, which might result in the unchanged staffing needs.

- Jurisdictions with more ambitious and active clean energy policies or initiatives tend to have more staff members but not necessarily higher staff-to customers ratio in relevant regulatory agencies;

- Staff's skill sets and expertise are very similar across different regulatory models; and,

- The divisions under regulatory agencies are organized by function, like engineering, policy research, personnel, administration, etc.; these organizational breakdowns are similar across different regulatory models.

Based on the analysis of representative jurisdictions, we anticipate the following potential impacts on the staffing requirements of related agencies.

- The impact of an **Outcomes-based PBR model** on staffing needs is inconclusive, since the staffing needs increased in the UK but stayed constant in Ontario after the implementation of this model;

- Implementation of the **Conventional PBR with Light HERA model** would potentially increase the staffing needs; and,

- Implementation of **the Hybrid model** could result in higher staffing needs than the status quo.

Furthermore, as mentioned in Task 1.3.4 and 1.4.3, the oversight management and staffing needs of related State agencies and stakeholders will be affected by various factors other than the regulatory model. Although the Hawaii PUC only regulates four electric utility companies,[3] Hawaii's aggressive renewable portfolio standards ("RPS") and other policy goals entail additional challenges to the regulatory and policy agencies. These other factors may require more staff members in these agencies, regardless of the regulatory model selected. Moreover, this analysis is a relative comparison for the purposes of comparing alternative utility ownership

[3] As discussed in Section 3.1, in addition to the electric utilities, the Hawaii PUC also regulates gas, telecommunications, water carriers and motor carriers transportation, as well as water and waste-water services.

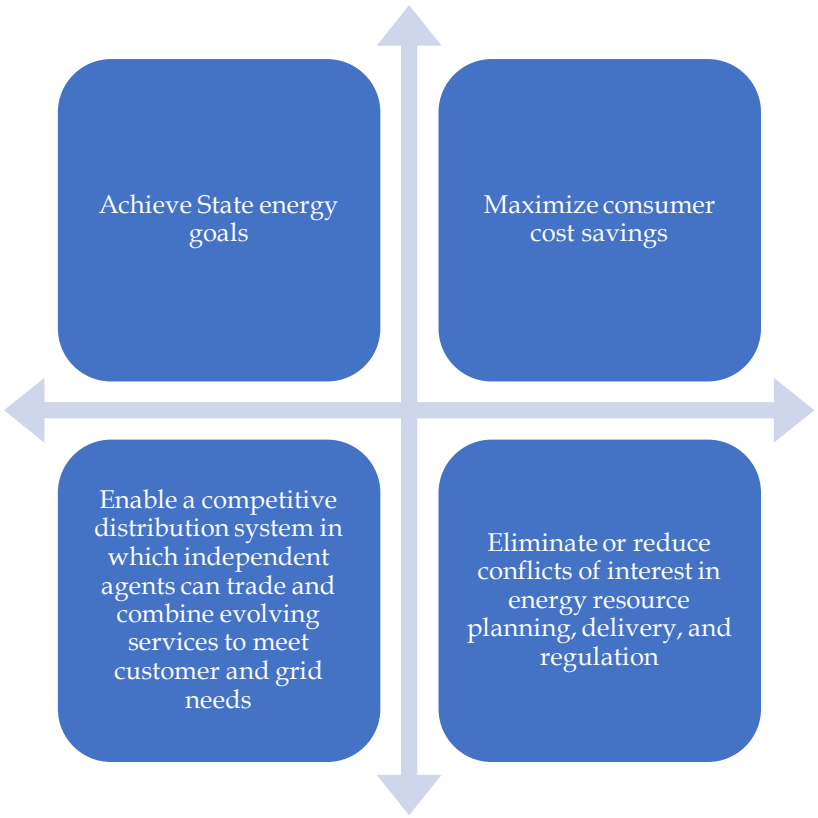
models. The study was not designed to assess whether or not the Hawaii PUC was appropriately staffed to meet the current demands. Our analysis was not intended to be used as an assessment of the appropriate staffing level given the specific considerations and issues for the Hawaii PUC and DCA, which is outside the scope of this study.

2 Introduction and scope

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission on a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[4] was contracted to perform this study.[5]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[6] listed in Figure 1.

Figure 1. State's key criteria in evaluating the models



Source: Scope of Services under Contract No. 65595

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In

[4] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[5] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[6] House Bill No. 1700 Relating to the State Budget.

addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[7]

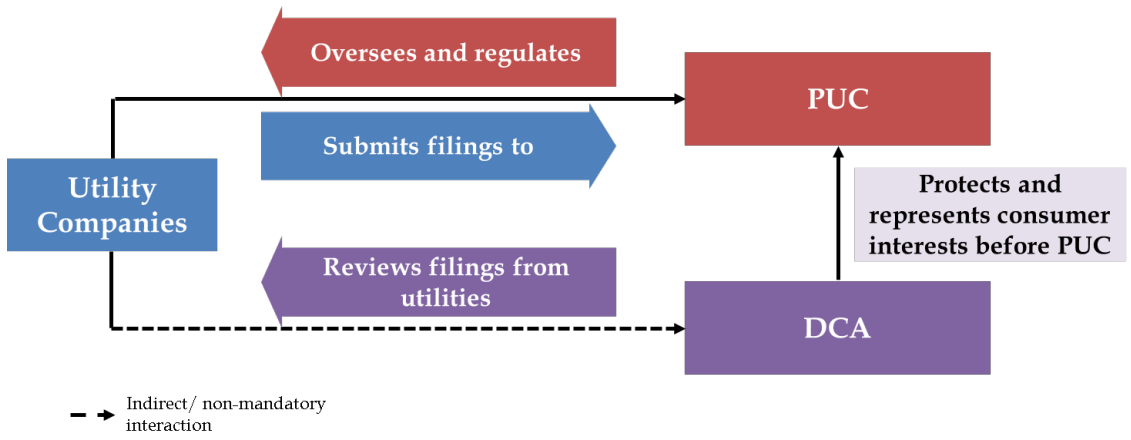
This deliverable corresponds to Task 2.3.4 in the project scope of work. It provides an estimate of the potential impacts a change in the regulatory model may have on the expertise and staffing requirements of related State agencies and stakeholders such as Hawaii PUC, and the DCA. In addition, it includes analysis of best practices in terms of staffing and expertise at public utility commissions and consumer advocate offices.

[7] Hawaii Contract No. 65595. Scope of Services.

3 Current staffing structure

A change in utility ownership might impact the various state entities that help oversee that utility or provide it with policy guidance. To assess the potential impact, we focus on State agencies and regulators that utilities usually interact with, including the Hawaii Public Utilities Commission ("PUC") and the Hawaii Division of Consumer Advocacy ("DCA"). Figure 2 summarizes the main interactions between these entities. All the utility companies in Hawaii are overseen and regulated by the PUC. Utilities are required to submit filings to the PUC regarding their proposed rates, changes, and future plans, and power purchase agreements ("PPAs") with generators, to name a few. Although utility companies are not required to report to the DCA directly, the DCA reviews filings from utilities and represents consumer interests before the PUC. These agencies are the most likely to be impacted by any ownership change of Hawaii's utility companies. We will discuss the current staffing structure of each entity below.

Figure 2. Utilities' interaction with PUC and DCA



Source: PUC, DCA, and LEI analysis.

3.1 Hawaii Public Utilities Commission

The primary duty of the PUC is to "*protect the public interest by overseeing and regulating public utilities to ensure that they provide reliable service at just and reasonable rates.*"[8] Entities that are regulated by the PUC include companies that provide electricity, gas, telecommunications, water carriers, and motor carriers transportation, as well as water and waste-water services. In addition, the Hawaii PUC directly oversees Hawaii Energy, funded by a public benefits fund, and the Hawaii One Call Center, a mandatory "Call Before You Dig" program, among other programs. All the electricity utilities, namely Hawaiian Electric Company, Inc. ("HECO"), Maui Electric Company, Limited ("MECO"), Hawaii Electric Light Company, Inc ("HELCO"), and Kauai Island Utility Cooperative ("KIUC"), are under the authority of the PUC.

[8] HPUC. *Introduction*. Website< http://puc.hawaii.gov/about/introduction/>. Access date: October 30, 2017.

As requested by the Act 108, Session Laws of Hawaii 2014, the PUC was transferred from Department of Budget & Finance ("DBF") to the Department of Commerce and Consumer Affairs ("DCCA").[9] Given its increased administrative decision-making authority, the PUC also received additional funding that led to more staffing positions.[10] As of December 2016, the PUC has a total of 65 full-time, permanent, and funded positions; 85% of those positions were filled in FY 2016.[11] Positions include administrative, director, attorneys, engineers, auditors, researchers, investigators, neighbor island representatives, documentation staff, and clerical staff.[12] The PUC expects to fill the remaining ten vacancies in FY 2017.[13] The funded positions in each division and relevant background/expertise of staff are summarized in Figure 3.

Figure 3. Number of staff and their major background/ expertise in each division in Hawaii PUC

Divisions	Approximate # of Staff	Major background/ expertise of Staff
Office of the Commissioners	7	management, development, administration
Commission Counsel	11	legal advisory
Audit Section	4	auditing, research, analysis
Engineering Section	4	engineering, analysis
Consumer Affairs and Compliance	9	public relations, complaint resolution
Administrative Support Services	10	documentation, clerical services, information technology, coordination
Fiscal Section	3	fiscal and procurement
Personnel Section	2	recruitment, human resources
Policy and Research	15	analysis, economics, research

Source: Hawaii PUC. Response to LEI's data requests via email on November 21, 2017.

3.2 Division of Consumer Advocacy

The Division of Consumer Advocacy ("DCA") is under the DCCA. The DCA is a state agency established to "*protect and represent consumer interests before the Hawaii PUC, the Federal Communications Commission, and other local and federal agencies.*"[14] It should be noted that the DCA "*assists and represents customers of utility services as a whole rather than a single customer or select group*

[9] "Commission History." *HPUC*. Website. < http://puc.hawaii.gov/about/history/>. Access date: October 30, 2017.

[10] HPUC. *Annual Report for Fiscal Year 2016* (July 1, 2015 to June 30, 2016). December 2016, page 5.

[11] Ibid, page 5.

[12] HPUC. *Annual Report for Fiscal Year 2012-13*. January 2014, page 2.

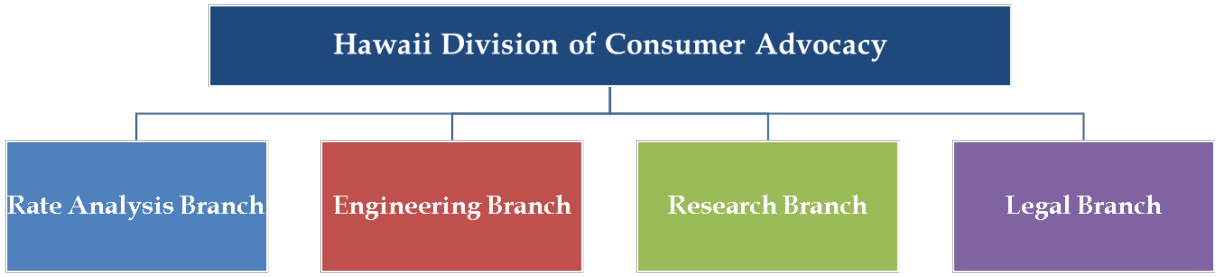
[13] HPUC. *Annual Report for Fiscal Year 2016* (July 1, 2015 to June 30, 2016). December 2016, page 5.

[14] "Divisions." *DCCA*. Website. < http://cca.hawaii.gov/divisions/>. Access date: October 31, 2017.

of people."[15] More specifically, the DCA reviews filings from public utility and transportation companies, including rate and tariff changes, capital improvement projects, integrated resource plans, certificates for authority to operate, etc.[16] In representing consumer interests before the PUC, the DCA files written statements of position or provides testimonies based on its analysis of "*financial and statistical data, prior docketed material, industry standards, and the information provided by utility and transportation companies to support their applications.*"[17]

As of 2016, DCA had 19 employees, including an Executive Director, a secretary, a utilities/transportation officer, a utilities/transportation specialist, an education specialist, rate analysts, researchers, engineers, attorneys, and clerical support.[18] Most of the professional staff are under four branches, including the Rate Analysis Branch, the Engineering Branch, the Research Branch, and the Legal Branch as shown in Figure 4 below. The Rate Analysis Branch reviews capital structure of utilities and develops recommendations relating to rates. The Engineering Branch analyzes and makes recommendations on technical matters. The Research Branch analyzes and provides advice relating to the operations of and changes to utilities. The Legal Branch provides legal representation before regulatory agencies.[19]

Figure 4. Organizational chart of Hawaii DCA



Source: DCA. 2016 Compliance Resolution Fund Report.

[15] Ibid.

[16] DCA. *2016 Compliance Resolution Fund Report*. Page 22.

[17] Ibid.

[18] Ibid.

[19] Ibid, Page 22-23.

4 Best practices in staffing in other jurisdictions

4.1 Public Utilities Commission

In the US, PUCs or PSCs consist of three to seven appointed or elected commissioners and professional staff who may carry the following functions.[20]

- *managing their personnel, facilities, operations: administrative staff;*
- *conducting hearings: administrative law judges, hearings examiners, attorneys;*
- *analyzing rate filings through testimony (usually pre-filed): economic, accounting and engineering staff;*
- *enforcing rules and tariffs: compliance staff, attorneys;*
- *providing technical assistance to the commissioners: advisory staff;*
- *legal analysis: attorneys;*
- *legislative analysis and reporting: policy staff; and facilitating alternative dispute resolution processes, including settlement negotiations among parties.*

Staffing in the Hawaii PUC conforms to the industry standard, given that it has three Commissioners that are appointed by the Governor and subject to confirmation by the state Senate.[21] Its functions are also consistent with the ones provided above.

The organizational chart of California PUC was used as an example to illustrate the functional lines of a typical commission in the *Electricity Regulation in the US: A Guide* published by The Regulatory Assistance Project (or "the Guide"), as shown in Figure 5. Although not every PUC or PSC is the same, this organizational chart provides an overview of the range of functions that a commission performs.[22] According to the Guide, in some states, "*the commission staff does not prepare any evidence of its own.*"[23] And in a few states, the consumer advocate is part of the commission.[24] Also, since each commission regulates a different number of utilities which serve a different number of customers, the number of staff that a PUC needs to employ varies as well. The Hawaii PUC has some divisions that are like the ones in the California PUC. For example, the Hawaii PUC has a Consumer Affairs and Compliance division which is like the Consumer Services & Information and the Consumer Protection & Safety divisions in the California PUC. But the Hawaii PUC also has some functional divisions like Engineering Section, Fiscal Section, Policy, and Research division that the California PUC does not have. The California PUC,

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[20] Lazar, J. *Electricity Regulation in the US: A Guide. Second Edition*. Montpelier, VT: The Regulatory Assistance Project. 2016. pages 25-26.

[21] Section 26-34 of the Hawaii Revised Statutes.

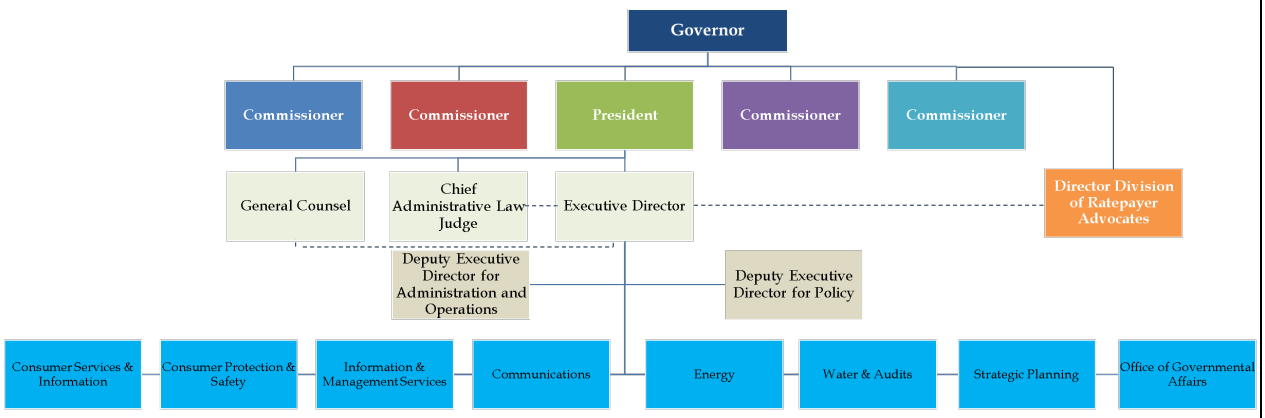
[22] Lazar, J. Electricity Regulation in the US: A Guide. Second Edition. Montpelier, VT: The Regulatory Assistance Project. 2016. pages 25-26.

[23] Ibid.

[24] Ibid.

however, has divisions that are specialized in certain industries like the Energy Division and the Water & Audits division that the Hawaii PUC does not have.

Figure 5. Organizational chart of California PUC



Source: CPUC, 2016. Lazar, J. Electricity Regulation in the US: A Guide. Second Edition. Montpelier, VT: The Regulatory Assistance Project. 2016. Page 26.

4.2 Division of Consumer Advocacy

According to the National Association of State Utility Consumer Advocates ("NASUCA"), state utility consumer advocate offices were created by state legislatures in the 1970s, when natural gas and electric prices were very high during energy crises.[25] The consumer advocates were responsible for challenging the rate increases by the utility monopolies. Later, as the competition and industry deregulation evolve, state consumer advocates shift their focus to "*consumer protection issues, including service quality, reliability, and price stability.*"[26] The names of these offices vary in different states, including "*People's Counsel, Public Counsel, Consumer Advocate, and Consumer Counsel.*"[27] The Hawaii DCA has these tasks as part of its mandate.

Based on LEI's research, the DCA in Colorado could serve as a good example of a well-organized office, as the DCA in Colorado helped the customers save $66 for every dollar the DCA spent. The Colorado Department of Regulatory Agencies has been checking the state regulation through the various process for 40 years. They believed that "*when unnecessary or overly restrictive regulations create barriers for new practitioners and businesses to succeed, the effects can reverberate throughout the economy.*"[28] The Office of Consumer Counsel ("OCC") under the Department of Regulatory Agencies serves as the consumer advocate office in Colorado. The OCC was created

[25] "Who We Are – The History of NASUCA." *NASUCA*. Web. <http://nasuca.org/about-us/>.

[26] Ibid.

[27] Ibid.

[28] "Celebrating 40 Years of Sunset and Regulatory Reform." *Colorado Department of Regulatory Agencies*. Website. <https://www.colorado.gov/pacific/dora-oprrr/40-years-reform>.

by the legislature in 1984 to "*represent the public interest and the specific interests of residential, small business and agricultural consumers in electric, natural gas, and telecommunications rate and rulemaking cases before the PUC, federal agencies, and the courts*."[29] The passing of *SB 271* in the legislative session eliminated telecommunications from the OCC's advocacy, which left OCC to focus on energy-related issues.[30]

The OCC has an eleven-member Utility Consumers' Board ("UCB") created statutorily. As the recent legislation required, seven of the members are appointed by the Governor, and each of the seven Congressional districts in the state shall be represented.

Moreover, "*no more than four Board members can be affiliated with the same political party*."[31] At least one member of the seven appointments will be representing expertise in agriculture, and at least two members of the seven appointments will be owners of the small business with 100 or fewer employees.[32] For the four remaining seats, "*the President of the Senate, Speaker of the House of Representatives, the Minority Leader of the Senate, and the Minority Leader of the House of Representatives shall each appoint one member.*"[33] The UCB is primarily responsible for providing general policy guidance and oversight to the OCC and its director. The Attorney General should advise the OCC and UCB on all legal matters and provide representation in proceedings.[34]

In addition, the OCC has eleven staff members in total, including seven operational staff (director, deputy director, admin, four technical analysts) and four legal staff (three attorneys and one legal assistant).[35] The background of technical analysts includes economics, engineering, policy analysis, etc.[36] Qualified external experts are also contracted with the OCC to perform research and appear as an expert witness in proceedings.[37]

The Hawaii DCA has the same responsibilities that the OCC has, but it has six more staff members per 100,000 customers. Like the OCC, the Hawaii DCA also has staff members who focus on

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[29] "About the Office of Consumer Counsel." *Colorado Department of Regulatory Agencies*. Web. <https://www.colorado.gov/pacific/dora/about-office-consumer-counsel>.

[30] Ibid.

[31] "About the OCC – Utility Consumers' Board." *Colorado Department of Regulatory Agencies*. Web. <https://www.colorado.gov/pacific/dora/what-we-do-OCC>.

[32] Ibid.

[33] Ibid.

[34] Ibid.

[35] Tim Villarosa, Deputy Director of the Office of Consumer Counsel. Reply to LEI's data request via email. November 27, 2017.

[36] "Advocacy – What We Do." *Colorado Department of Regulatory Agencies*. Web. <https://www.colorado.gov/pacific/dora/what-we-do-OCC>.

[37] Ibid.

analysis, engineering, and legal tasks. But the Hawaii DCA has most of the professional staff divided into four functional branches, while the OCC does not.

As for funding, the OCC is "*cash funded by the PUC Fixed Utility Fund into which public utilities pay to cover the cost of regulation*" and "*no state General Fund dollars are appropriated to the OCC.*"[38] In the Fiscal Year 2015-2016, the annual budget for OCC totals $1.7 million (including personal and legal services, operating, information technology, leased space, and indirect costs), and the OCC managed to save consumers $111 million in energy rate hikes through singular and joint efforts with the PUC staff.[39] In another word, for every dollar the OCC spent (including the management and staffing expenditures), Colorado consumers saved $66 in total.[40]

In summary, lessons learned from the OCC in Colorado can be summarized in two points. First, the statue had specific requirements on the appointed UCB members, which brings representatives from different fields with diverse expertise and political views. It is an effective way to guarantee the OCC represents interests of general consumers, especially those with less representativeness (i.e., small business) rather than those with vested interests. The Hawaii DCA does not have arrangements that are similar to this. Second, the OCC is relatively transparent and cost-effective, as it can document the consumer savings for every dollar the OCC spent.

5 Regulatory and policy staffing requirements under each regulatory model

5.1 Key issues

As with the broader project, in this phase, we seek to understand whether a change in a regulatory model affects the regulatory and policy staffing requirements of agencies such as the PUC and

[38] Colorado Department of Regulatory Agencies. *Office of Consumer Counsel FY 2015/2016 Annual Report*. Page 4.

[39] Ibid, page 3.

[40] Ibid, page 11.

DCA and, if so, what the impacts are. In Section 3, we summarized the current staffing of these agencies in Hawaii. In this section, we reviewed and evaluated the regulatory and policy staffing requirements under each regulatory model in other jurisdictions. We assessed the staffing requirements of these agencies in representative jurisdictions under each regulatory model.

5.2 Methodology and comparators

Slightly different from the approach that was applied in Task 1.3.4 under ownership models, in this memo, the Project Team focused on the change of staffing levels before and after a change in regulatory models.

As summarized in Figure 6, for the Outcomes-based PBR, the UK and Ontario were selected as examples since both have set up Outcomes-based PBR. Illinois, Alberta, and New South Wales of Australia were chosen for the Conventional PBR with Light HERA model.[41] Since there is no Hybrid model that currently exists in other jurisdictions, we looked at New York which is in the process of transforming to a similar hybrid model including both distribution-focused platform as well as Outcomes-based PBR. New York also has an ISO.

Figure 6. Staff-to-customers ratio in representative states with different regulatory models

Number of staff in relevant state agencies

	Status quo	Outcomes-based PBR			Conventional PBR with HERA Light				The Hybrid Model
	HI	UK	Ontario	Average	Malaysia	Alberta	NSW	Average	New York
PUC	65	834	178	506	301	57	151	170	525

Number of retail electric customers

	Status quo	Outcomes-based PBR			Conventional PBR with HERA Light				The Hybrid Model
	HI	UK	Ontario	Average	Malaysia	Alberta	NSW	Average	New York
Total	*506,216*	*28,000,000*	*5,111,254*	*886,304*	*8,204,328*	*1,750,000*	*3,437,167*	*773,356*	*2,781,568*

Number of staff : 100,000 customers

	Status quo	Outcomes-based PBR			Conventional PBR with HERA Light				The Hybrid Model
	HI	UK	Ontario	Average	Malaysia	Alberta	NSW	Average	New York
PUC	12.8	3.0	3.5	3.2	3.7	2.4	4.4	3.5	18.9

Notes: (i) staff numbers under DCA are excluded from this chart since comparable DCA does not exist in the UK, Ontario, and Malaysia and the staff numbers are not publicly available in Alberta, NSW, and New York. (ii) sources of these numbers are provided in corresponding sections below. (iii) 2016 numbers were used for all jurisdictions to be consistent with the available data in Hawaii.

Also, it is important to caveat that the management structure and staffing arrangement of the PUC and DCA are affected by many factors. The sample jurisdictions were selected based on their primary regulatory models, not on their comparability to the state of Hawaii in terms of the number of customers, the number of utilities, or level of policy sophistication. However, to make the number of staff comparable, the number of customers is used to calculate the staff-to-customers ratio (number of staff: 100,000 customers) in Hawaii and each representative state. As

[41] HERA currently does not exist in either Hawaii or other jurisdictions, so the Project Team focused on the analysis of conventional PBR only for this model.

the numbers suggested in Figure 6, even with the same regulatory model, the size of regulatory agencies may vary.

It should be noted that the policy ambition and complexity also have a critical impact on the staffing needs. For instance, as shown above, New York has the highest staff-to-customers ratio among all the sample jurisdictions. The high ratio is driven by the ambitious energy and environment policy goals and various corresponding initiatives in its Reforming the Energy Vision ("REV") initiative.

5.2.1 Outcomes-based PBR

The UK and Ontario were selected as representative jurisdictions for the Outcomes-based PBR model, primarily due to the number of years of experience with PBR, as well as the characteristics of their PBR regimes. The Project Team found that given the UK's example, the staffing needs might increase due to the setup of Outcomes-based PBR; but based on Ontario's experience, the staffing needs might not change much.

The UK has extensive PBR experience spanning over two decades. In particular, the UK's "Revenue = Incentives + Innovation + Outputs" ("RIIO"), an example of outcomes-based PBR, was quoted in the Hawaii PUC's order on PBR as "*one of the best-known examples of PBR in practice*."[42] Further details such as the overview of the market, the regulatory framework, and the history of transition and recent developments in the UK can be found in Task 2.2.2 (Assessment of current markets under each regulatory model).

Similarly, Ontario was selected as a representative jurisdiction as it also employs an Outcomes-based PBR approach. As part of its PBR regime, the Ontario Energy Board ("OEB") established the Renewed Regulatory Framework for Electricity ("RRFE") in 2012. As per the OEB, "*[the RRFE] articulates the OEB's goal for an outcomes-based approach to regulation which aligns the interests of customers and utilities*."[43] As such, key principles include:

- "*the expectation for continuous improvement;*
- *robust integrated planning and asset management that paces and prioritizes investments,*
- *strong incentives to enhance utility performance;*
- *ongoing monitoring of performance against targets; and*

[42] Hawaii PUC. *Instituting a Proceeding to Investigate Performance-Based Regulation* (Order No. 35411). Docket No. 2018-0088. April 18, 2018.

[43] "Handbook for Utility Rate Applications." *OEB.* October 13, 2016. <https://www.oeb.ca/oeb/_Documents/Regulatory/OEB_Rate_Handbook.pdf>

- *customer engagement to ensure utility plans are informed by customer expectations."*[44]

The OEB believes that emphasis on the results rather than the activities will better lead to alignment with customer preferences, enhanced distribution productivity, as well as the spurring of innovation.[45] With regards to outcomes, utilities are responsible for identifying outcomes that would be valuable to customers, and accordingly, explain how said outcomes would be achieved under its plans and proposed costs. The outcomes are then associated with performance metrics, determining whether the outcomes have been achieved or not.[46] The OEB has identified four categories of outcomes to be achieved through the framework, namely customer focus, operational effectiveness, public policy responsiveness, and financial performance.[47] The OEB has also established a set of performance metrics for electricity distributors in its Performance Scorecard; all other utilities (i.e., natural gas transmission and distribution, electricity transmission, and Ontario Power Generation ("OPG")) propose their own scorecard, similar to the one developed for distributors.[48]

On average, the representative states had an average of approximately four staff per 100,000 customers in 2016 in the PUC, which is around one third of the staff-to-customers ratio in the Hawaii PUC as of 2016 (i.e., 13 staff per 100,000 customers).

Figure 7. Staff-to-customers ratio in UK and Ontario compared to Hawaii

Number of staff : 100,000 customers

	Status quo	Outcomes-based PBR		
	HI	UK	Ontario	Average
PUC	12.8	3.0	3.5	3.2

Note: Although 2018 numbers are available for the UK, 2016 numbers were utilized for consistent comparison. Further, Ontario's staffing levels are based on budgeted headcount; actual headcount (FTEs) were not available. The total staff-to-customers ratios have been rounded up.

Source: Ofgem annual report 2015/2016; OEB Business Plan 2016-19.

5.2.1.1 PUC

United Kingdom

[44] Ibid, page 2.

[45] Ibid, page 2.

[46] OEB. *Handbook to Utility Rate Applications*. October 13, 2016. p. 15.

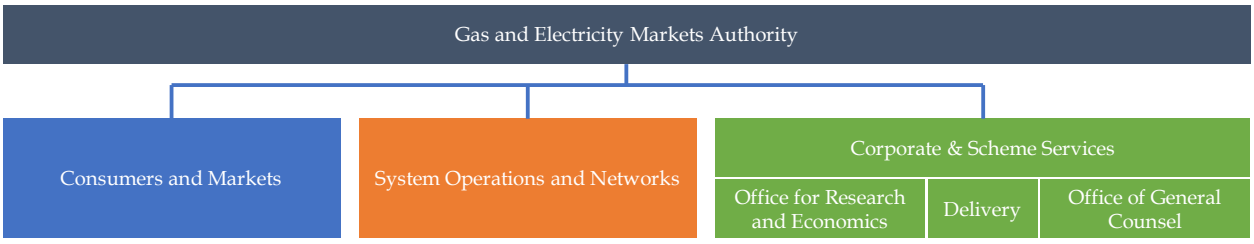
[47] Ibid, p. 15.

[48] Ibid, p. 16-17.

Generally, Ofgem's offices are organized by function; as such, the divisions cover not only electric utilities, but also natural gas utilities. The Hawaii PUC on the other hand also covers telecommunications utilities, as well as the transportation and water/wastewater industries.

As of March 2018, the UK's Office of Gas and Electricity Markets ("Ofgem") had 724 permanently employed staff (average number of full-time equivalent ("FTE") people employed).[49] This is significantly more employees than that of both the OEB and the Hawaii PUC.

Figure 8. Ofgem organizational chart (post-structural reorganization)



Divisions	Function
Consumers and Markets	Looks after the interests of consumers in the energy market (wholesale and retail markets, enforcement)
System Operation and Networks	Focused on price controls (resources will particularly focus on the next round due to start in 2021) and ensuring maximum consumer benefits
Corporate & Scheme Services	Provides business support services and runs environmental schemes for Government

Note: The above divisions are for both the gas and electricity markets, and thus is representative of Ofgem as a whole.

Source: Ofgem, 2018.

Ofgem underwent organizational restructuring in April 2018, reducing the number of divisions from seven to three to "*better focus on protecting consumers*."[50,51] The three divisions are comprised of Consumers and Markets, System Operation and Networks, and Corporate & Scheme Services. In turn, Ofgem and its divisions are governed by the Gas and Electricity Markets Authority ("GEMA"). The new organizational structure and its functions are depicted

[49] Staffing levels post-organizational restructuring are lower than that of 2016 (i.e., 834 FTEs).

[50] "Ofgem reorganization." *Ofgem.* January 15, 2018. Web. August 21, 2018. <https://www.ofgem.gov.uk/publications-and-updates/ofgem-reorganisation>

[51] Prior to organizational restructuring, Ofgem's divisions were comprised of the following: Corporate Affairs, Consumers and Competition, Energy Systems, Networks, Improving Regulation, Corporate Functions, and E-Serve. (Source: "New Ofgem organizational structure." *Ofgem.* January 12, 2016. Web. August 21, 2018. < https://www.ofgem.gov.uk/publications-and-updates/new-ofgem-organisational-structure>

in Figure 8, while the number of staff and details regarding the background and expertise of the staff pre-reorganization are listed in Figure 9

Note: The above divisions are for both the gas and electricity markets, and thus is representative of Ofgem as a whole.

Source: Ofgem, 2018.

.[52]

Figure 9. Number of staff members in each division of Ofgem and their major background/expertise (pre-structural reorganization)

Divisions	Approximate # of Staff	Major background/expertise of Staff
Regulatory	366	policy advisory, planning, administration
E-Serve	241	management, administration, development & implementation, operations
Corporate Services	117	management, budgets, risk management, finance, accounting, procurement

Note: Although prior to restructuring, Ofgem's divisions consisted of Corporate Affairs, Consumers and Competition, Energy Systems, Networks, Improving Regulation, Corporate Functions, and E-Serve, Ofgem's annual reports document divisional staffing numbers under the umbrella terms shown in Figure 8.

Source: Ofgem, 2018.

Ofgem's divisional structuring is more streamlined (i.e., has fewer divisions) than that of the Hawaii PUC. Nevertheless, both Ofgem and the Hawaii PUC have divisions dedicated to consumers (i.e., Consumer Affairs and Compliance in the Hawaii PUC and Consumers and Markets in the restructured Ofgem), a division dedicated to economics and research (i.e., Policy and Research in the Hawaii PUC and Office for Research and Economics sub-division under Corporate & Scheme Services in the restructured Ofgem) as well as an Office for Counsel (i.e., Commission Counsel in the Hawaii PUC and Office of General Counsel sub-division under Corporate & Scheme Services in the restructured Ofgem). Ofgem does not have a dedicated audit and engineering division, or an Office of the Commissioners as the Hawaii PUC does.

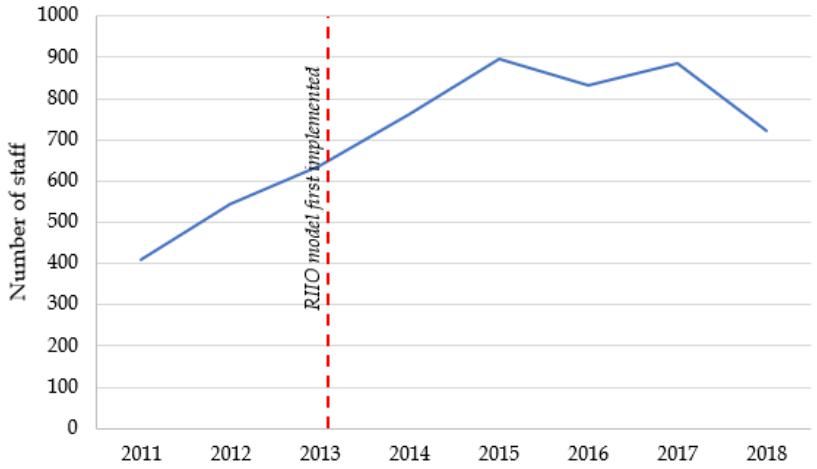
As can be seen, by the above numbers, Ofgem is significantly larger in terms of number of staff than the Hawaii PUC. Additionally, the Project Team notes that after the implementation of the RIIO in 2013, the number of staffing increased by 17% (from 545 in 2012 to 637 in 2013).[53] In the following year (2014), the number of staffing further increased by 19% to 761 staff, to be followed by another 18% increase in 2015 to 896 staff. The following year (2016) saw a decrease of 7% to

[52] Details regarding divisional staffing (i.e. number of FTEs), are not available post-structural reorganization. This will likely be reflected in Ofgem's 2018-19 annual report (for the year ending March 31, 2019).

[53] In addition, external experts were hired to help Ofgem with reviewing the PBR plans as well.

834 staff, only to increase again by 6% in 2017 to 886 staff.[54] Nonetheless, staffing levels decreased once again in the most recent year; in the year ending March 31, 2018, Ofgem had 724 permanently staffed FTEs, approximately 18% less than that of 2017. Overall, the adoption of the RIIO model has increased the number of staff in UK for the first several years. Likewise, the implementation of the Outcomes-based model may result in a general increase in staffing members in the Hawaii PUC, if implemented.

Figure 10. Ofgem's staffing levels before and after implementation of the RIIO model



Source: Ofgem annual reports 2010/11 – 2017/18.

Ontario

Like Ofgem, the OEB regulates both the natural gas and electricity sectors and similarly, divisions are organized by function. It does not cover telecommunications utilities, or the transportation and water/wastewater industries as the Hawaii PUC does.

Similar to PUCs or PSCs in the US, the OEB acts as the energy regulator for Ontario. With the implementation of the PBR through RRFE in Ontario in 2012[55], the OEB staff's responsibilities increased and included the development of additional policies and processes pertaining to the RRFE, refine the scorecard, and develop additional incentive mechanisms.[56]

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[54] The average number of staff decreased in 2015/2016, and the decrease was primarily "*concentrated in staff at the lower grades*." The reason for this decrease was not specified. (Source: Ofgem. *Annual Report 2015/16*.)

[55] RRFE was first implemented in 2012, however PBR was first introduced in Ontario in 2007. Nonetheless, for the purposes of the regulatory model (i.e., Outcomes-based PBR), we will be focusing on the implementation of RRFE.

[56] OEB. *2014-2017 Business Plan.* < https://www.oeb.ca/oeb/_Documents/Corporate/OEB_Business_Plan_2014-2017.pdf>

As per the *2018 to 2021 Business Plan*, the OEB has budgeted a staff headcount of 192 FTEs over the planning period, in addition to 11 FTE Board Members. Similar to Ofgem, the most recent staffing levels of the OEB are higher than that of the Hawaii PUC. The organizational structure is depicted in Figure 11, while the details regarding the background and expertise of the staff in each division are listed in Figure 12.[57]

Figure 11. OEB organizational chart

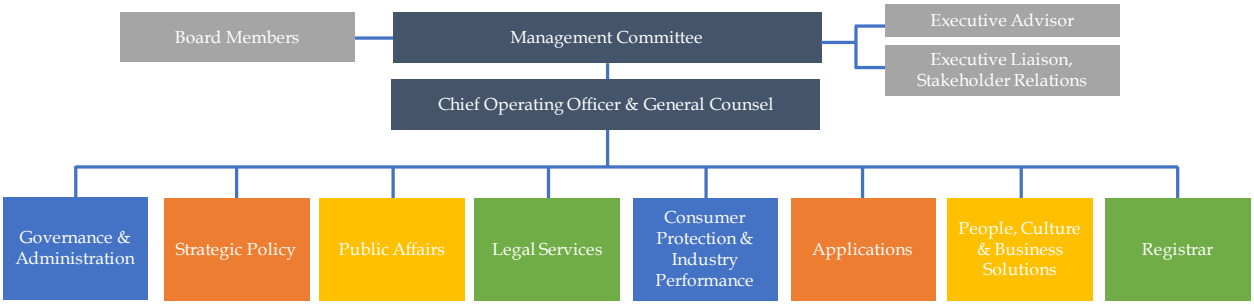


Figure 12. Divisions in OEB and major background/expertise of corresponding division's staff

Divisions	Major background/expertise of Staff
Management Committee	management, executive assistance
Chief Operating Officer & General Counsel	policy advisory, executive assistance
Governance & Administration	executive assistance, administration
Strategic Policy	strategic and policy advisory, risk management, business planning, executive assistance
Public Affairs	communications, media relations, stakeholder engagement, brand management
Legal Services	legal, strategic, and policy advisory, executive assistance
Consumer Protection & Industry Performance	management, customer assistance, auditing, licensing, compliance & enforcement
Applications	rates regulation, management, policy advisory
People, Culture & Business Solutions	human resources, finance, information technology, organizational development, procurement, facilities
Registrar	management, administration, policy advisory

Note: Staffing levels by division are not reported by the OEB.

Source: OEB.

In addition to having higher overall staffing levels than the Hawaii PUC, the OEB also has more divisions. Overall, the OEB's divisional structuring is similar to that of the Hawaii PUC in the sense that both have a Commission-level committee (i.e., the Management Committee in OEB and the Office of the Commissioners in the Hawaii PUC), General Counsel divisions (i.e., Chief Operating Officer & General Counsel in OEB and the Commission Counsel in the Hawaii PUC), divisions dedicated to administration (i.e., Governance & Administration in OEB and

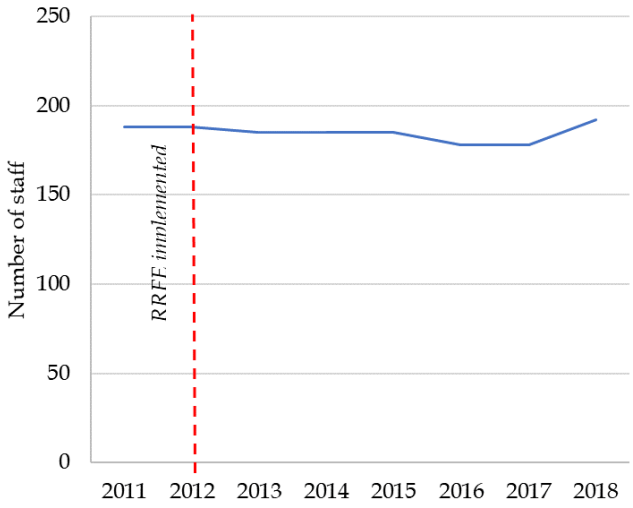
[57] Details regarding divisional staffing (i.e. number of FTEs), are not available post-structural reorganization. This will likely be reflected in Ofgem's 2018-19 annual report (for the year ending March 31, 2019).

Administrative Support Services in the Hawaii PUC), divisions dedicated to policy and research (i.e., Strategic Policy in OEB and Policy and Research in the Hawaii PUC), public relations divisions (i.e., Public Affairs in OEB and Consumer Affairs and Compliance in the Hawaii PUC), and human resource divisions (i.e., People, Culture & Business Solutions in OEB and Personnel Section in the Hawaii PUC).

Nonetheless, the OEB does not have a division dedicated to engineering and relevant analysis such as the Hawaii PUC's Engineering Section. The OEB also does not have a section performing auditing such as the Hawaii PUC's Audit Section; this activity is grouped along with customer assistance under the Consumer Protection & Industry Performance division. The Hawaii PUC, on the other hand, does not have a department dedicated to legal activities such as the OEB's Legal Services division.

While division-level staffing numbers are not available, LEI notes that total staffing level has not been significantly impacted since the implementation of the Renewed Regulatory Framework for Electricity ("RRFE") in 2012. As seen in Figure 13, year-over-year staffing levels have ranged from -4% to 8% year-over-year from 2011 (before RRFE was implemented) to 2018. One plausible explanation for this is that the OEB hires consultants to help it with its review of the utility's proposals on PBR, and therefore, it does not need to hire additional full time stuff to work on this.

Figure 13. OEB's staffing levels before and after implementation of RRFE



Note: The above staffing levels are based on "budged headcounts" of full-time staff positions over different time periods, and thus the Project Teams assumes that these are indicative of actual staffing levels. The budgeted headcount for 2014 and 2015 was not provided in OEB's *2014-2017* and *2015-2018 Business Plans*, respectively. As such, the budgeted headcount for 2014 and 2015 was assumed unchanged from OEB's *2013-2016 Business Plan Package* (i.e., a full-time headcount of 185 positions). Budgeted headcounts were not available for years prior to 2011. The staffing levels do not account for the number of Board Members.

Source: OEB *Business Plan* reports, 2011-2018.

5.2.1.2 DCA

While both the UK and Ontario have independent organizations to represent the interests of consumers, these groups are not government agencies such as the DCA in the State of Hawaii and thus cannot be compared with the DCA in terms of their staffing levels. Nonetheless, a brief discussion of these groups and their functions is provided below.

United Kingdom

The UK does not have public consumer advocacy groups such as the DCA in the State of Hawaii. Instead, in the UK, consumer advocacy for energy is undertaken by two non-governmental organizations namely Citizens Advice and the Energy Ombudsman.

Citizens Advice holds the "*statutory role as the consumer advocate for energy consumers, to represent consumers across the energy industry*."[58] It is a national charity network comprised of approximately 300 independent local charities across England and Wales.[59] The charity organization not only advises and supports consumers regarding gas and electricity complaints, but also in other areas such as employment benefits, debt and money, consumer goods, family, housing, law and courts, immigration, and health.[60]

The Energy Ombudsman is also another Ofgem-approved independent organization that helps "*handle disputes between energy companies and their customers, which includes domestic customers and micro businesses*."[61] It is a free service that is generally utilized if an energy supplier has not settled the consumer's complaint.

Ontario

Similar to the UK, Ontario does not have a public consumer advocacy group such as the DCA in the State of Hawaii. Rather, the Consumers Council of Canada is a not-for-profit, voluntary organization that represents the interests of residential customers in Ontario with regards to not only energy-related matters but also in issues pertaining to housing; justice, resolution & redress; digital economy; and product performance & safety. The Consumers Council of Canada is a member of the Canadian Consumer Initiative under the Office of Consumer Affairs, Industry

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[58] "Outcome of Ofgem price controls consultation "will be the acid test", says Citizens Advice." *Citizens Advice.* March 7, 2018. Web. August 22, 2018. < https://www.citizensadvice.org.uk/about-us/how-citizens-advice-works/media/press-releases/outcome-of-ofgem-price-controls-consultation-will-be-the-acid-test-says-citizens-advice/>

[59] Citizens Advice. *Annual report 2016/17.*

[60] "Welcome to Citizens Advice." *Citizens Advice.* Web. August 22, 2018. < https://www.citizensadvice.org.uk/>

[61] "About the energy ombudsman." *Ombudsman Services.* Web. August 22, 2018. < https://www.ombudsman-services.org/sectors/energy>

Canada, [62] and advocates for the Charter of International Consumer Rights.[63] As mentioned in Task 1.3.4 (Assessment of how each ownership model impacts staffing of State agencies and stakeholders), the Consumers Council of Canada comprised of thirteen Board of Directors (including a President, a Vice President, a Secretary, a Treasurer, eight Directors, and an Executive Director), with areas of expertise including, but not limited to, of law, auditing, economics, communications, consulting, and management. [64] While its function is similar to that of the Hawaii DCA, the Consumers Council of Canada is not further divided into divisions/functional branches. This means that it only has one division doing all the work.

5.2.2 Conventional PBR with Light HERA

The second recommended model is a hybrid of Conventional PBR with Light HERA, as described in Task 2.2.6. Since HERA does not exist yet in Hawaii and there is no jurisdiction that has both Conventional PBR and a standalone entity (other than ISOs) that enforce reliability standards, this section focuses on jurisdictions that implemented Conventional PBR only. Moreover, as HERA is a separate entity outside of Hawaii PUC, the Project Team assumes that it would have limited impact on staffing of existing state agencies, including the PUC and DCA. The Project Team finds that the staffing numbers of relevant state agencies would increase once the Conventional PBR is implemented.[65]

Malaysia, Alberta, and New South Wales of Australia were chosen as examples because they all have Conventional PBR mechanisms in place and they are single-state or single-province jurisdictions which are more comparable to Hawaii than a country.

In Malaysia, the Conventional PBR is also called the incentive-based regulation ("IBR") which started in 2014. It applies to the Tenaga Nasional Berhad ("TNB"), the only electric utility company in Peninsular Malaysia. Revenue cap is used for transmission, system operator, and Single Buyer (operational), while pure price cap is used for customer services (i.e., distribution utilities). The Suruhanjaya Tenaga ("ST"), the energy regulator in Malaysia, used the building blocks approach to set the price. In addition, to facilitate the implementation of PBR, the ST takes the responsibilities of reviewing historical cost performance, testing efficiencies through benchmarking, recommending performance targets, etc.

In Alberta, ENMAX, a vertically integrated utility in Calgary, was the first transmission and distribution utility to propose PBR in the province before the Alberta Utilities Commission decided to introduce the approach to the other electric and natural gas distribution utilities in

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[62] Consumers Council of Canada. *About Us – Canadian Consumer Initiative*. Web. < https://www.consumerscouncil.com/index.cfm?pagePath=About_Us/Canadian_Consumer_Initiative&id=18300>.

[63] "About the Council." *Consumers Council of Canada.* Web. August 22, 2018. < https://www.consumerscouncil.com/about>

[64] Consumers Council of Canada. *Annual Report of Activities 2016 – 2017*. Page 50 – 54.

[65] The staffing numbers in Illinois before and after the introduction of the Conventional PBR is not publicly available.

2011. As an example of Conventional PBR, Alberta uses the I-X approach,[66] price cap (for electric distributors), and revenue cap (for electric transmission) together with other adjustments, such as the earnings sharing mechanism and offramps/reopeners. With the implementation of the PBR, the AUC reviews multiple regulatory submissions related to the PBR. These include the PBR plan and capital tracker filing, and many more. The PBR plans are also more comprehensive than the cost of service filings as the utilities need to submit back up their plans and proposals.

As for New South Wales ("NSW"), the National Electricity Rules ("NER") requires the implementation of an incentive-based regulatory regime in the form of a revenue cap or some incentive-based variant, which was designed to foster efficient investment and operating practices and ensure the quality of service. In the NSW, transmission networks are regulated under weighted average price caps, using the building blocks approach. It also involves a symmetric earnings-sharing mechanism and off-ramps for transmission utilities. Similar to the other two examples mentioned above, the regulator in NSW had more responsibilities with the implementation of the PBR.

On average, the representative states had approximately three staff per 100,000 customers in 2016 for the PUC, lower than the staff-to-customers ratio in Hawaii as of 2016 (i.e., 13 staff per 100,000 customers). These will be discussed further in the succeeding sections.

Figure 14. Staff-to-customers ratio in Illinois, Alberta, and New South Wales compared to Hawaii

Number of staff : 100,000 customers

	Status quo	Conventional PBR with HERA Light			
	HI	Malaysia	Alberta	NSW	Average
PUC	12.8	3.7	2.4	4.4	3.5

Note: 2016 numbers were utilized for consistent comparison.

Source: ST, AUC, and IPART annual reports for 2016.

5.2.2.1 PUC

Malaysia

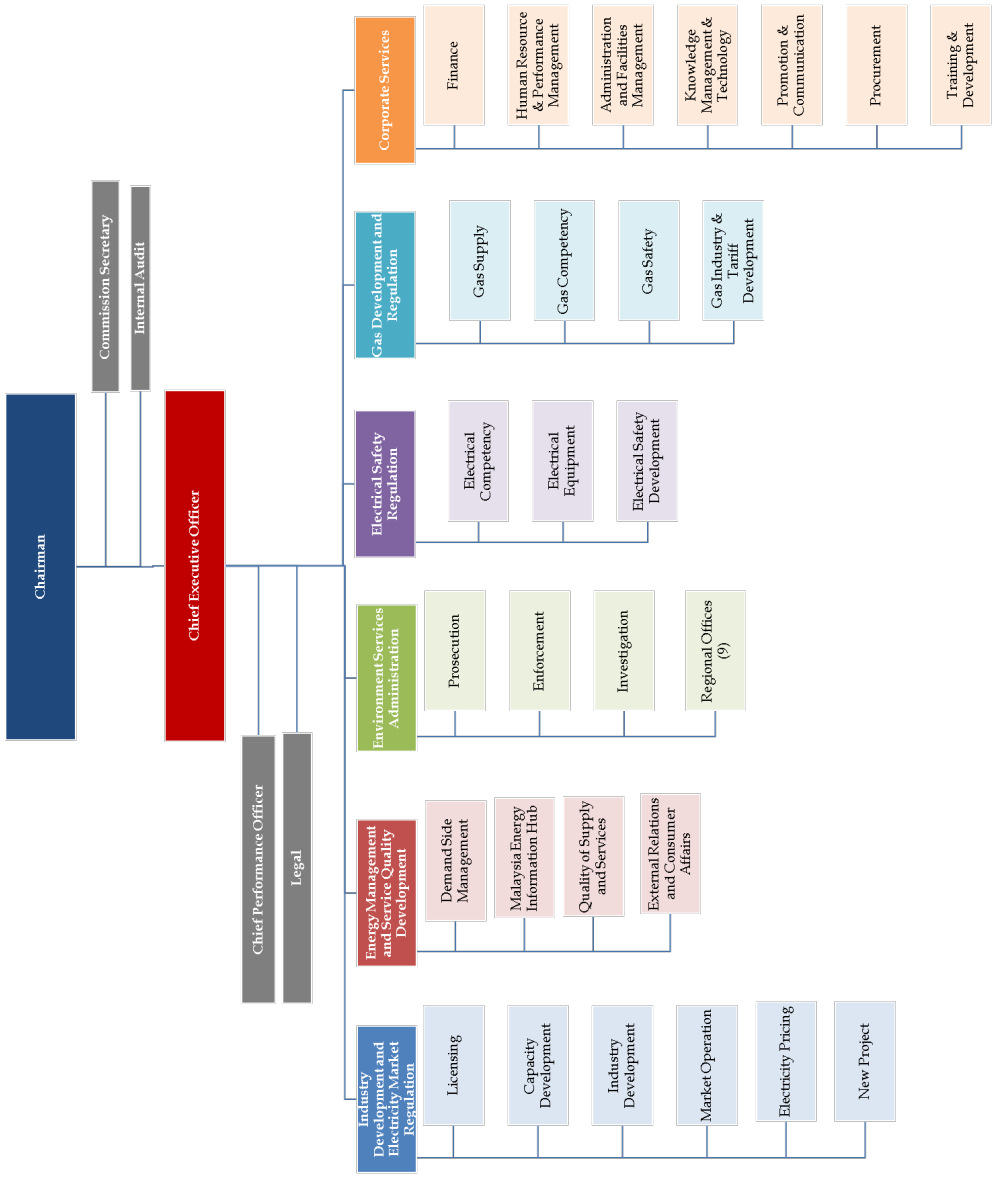
As discussed in Task 1.3.4, the Energy Commission or ST in Malaysia is a statutory body established under the Energy Commission Act 2001. Its primary responsibility is to regulate the energy sector, especially the electricity supply and piped gas supply industries in Peninsular Malaysia and Sabah.[67] As shown in Figure 15, the Chairman and Chief Executive Officers lead

[66] In Alberta, "I factor" means blended input-based inflation factor based on a Canada-wide construction price index and a provincial wage index. Each index weight is 0.5 in distribution and transmission. "X factor" was approved based on a survey of historical Total Factor Productivity studies and other jurisdictions' practices.

[67] Malaysia ST. *Overview of the Energy Commission*. Web. <http://www.st.gov.my/index.php/en/about-us2/overview-of-the-energy-commission>.

the ST. Staff is divided into six departments, including Industry Development and Electricity Market Regulation, Energy Management and Service Quality Development, Environmental Services Administration, Electrical Safety Regulation, Gas Development and Regulation, and Corporate Services.[68] Also, there are nine regional offices under the Environmental Services Administration department.

Figure 15. Organizational chart of Malaysia ST

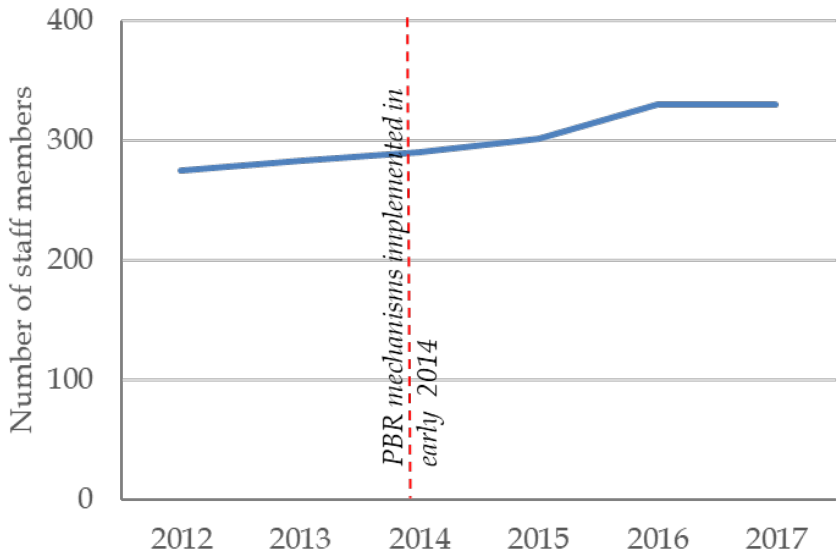


Source: Malaysia ST. Business Plan 2015-2020. December 2015. Page 25.

[68] Malaysia ST. *Business Plan 2015-2020*. December 2015. Page 25.

The PBR was introduced in early 2014 in Malaysia. In that year, the total number of employees in the ST increased by 2% from 283 to 290. In the following year (2015), the staffing number increased to 301.[69] Moreover, the total number is projected to increase over the next few years and will reach 350 by 2020.[70] Admittedly, other factors, i.e., the implementation of Single Buyer in 2014, might have contributed to this increase of staffing needs as well. More workload resulted from the PBR implementation implies that more staffing members might be required in the Hawaii PUC, if a Conventional PBR model is implemented.

Figure 16. ST's staffing levels before and after PBR implementation



Source: Malaysia ST. Business Plan 2015-2020. December 2015.

Alberta

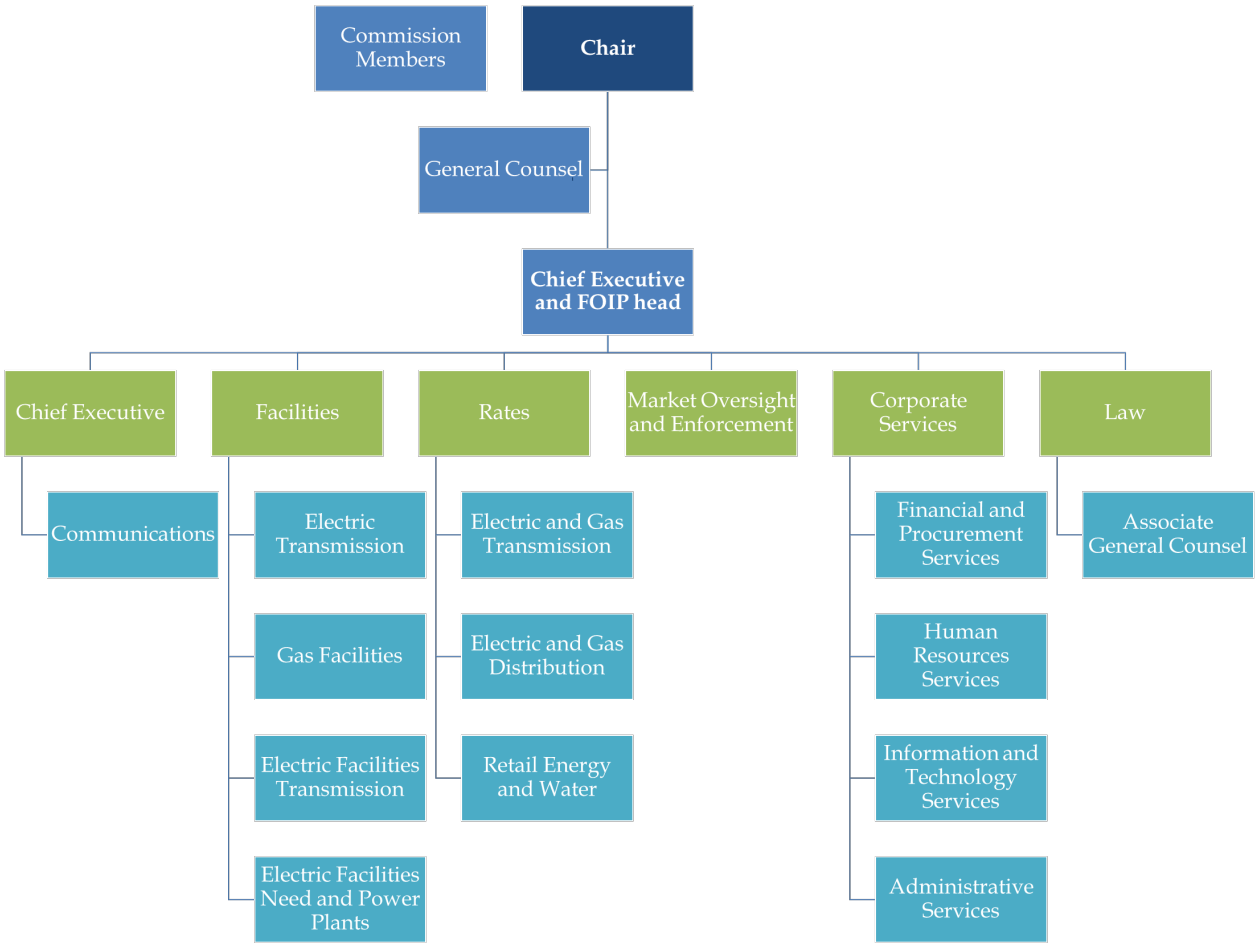
The Alberta Utilities Commission ("AUC"), similar to the Hawaii PUC, regulates the investor-owned electric, gas, water utilities and certain municipally owned electric utilities in Alberta, Canada.[71] However, different from the Hawaii PUC, the AUC does not cover telecommunication utilities or transportation. As shown in Figure 17, in addition to the Chair, Commission Members, General Counsel, and Chief Executive, the AUC consists of six major divisions, namely Chief Executive, Facilities, Rates, Market Oversight and Enforcement, Corporate Services, and Law.

Figure 17. Organizational chart of the Alberta Utilities Commission

[69] Ibid, page 26.

[70] Ibid, page 26.

[71] "About us – who we regulate." *AUC*. Web. <http://www.auc.ab.ca/pages/who-we-regulate.aspx>. Access date: August 30, 2018.



Note: FOIP – Freedom of Information and Protection of Privacy

Source: AUC. Organizational Chart. Web.
<http://www.auc.ab.ca/Shared%20Documents/AUCorganizationalchart.pdf>

There are around 60 employees in the AUC in the past three years (2015 – 2017),[72] but the numbers of employees in the years before the implementation of Conventional PBR are not publicly available.[73]

New South Wales

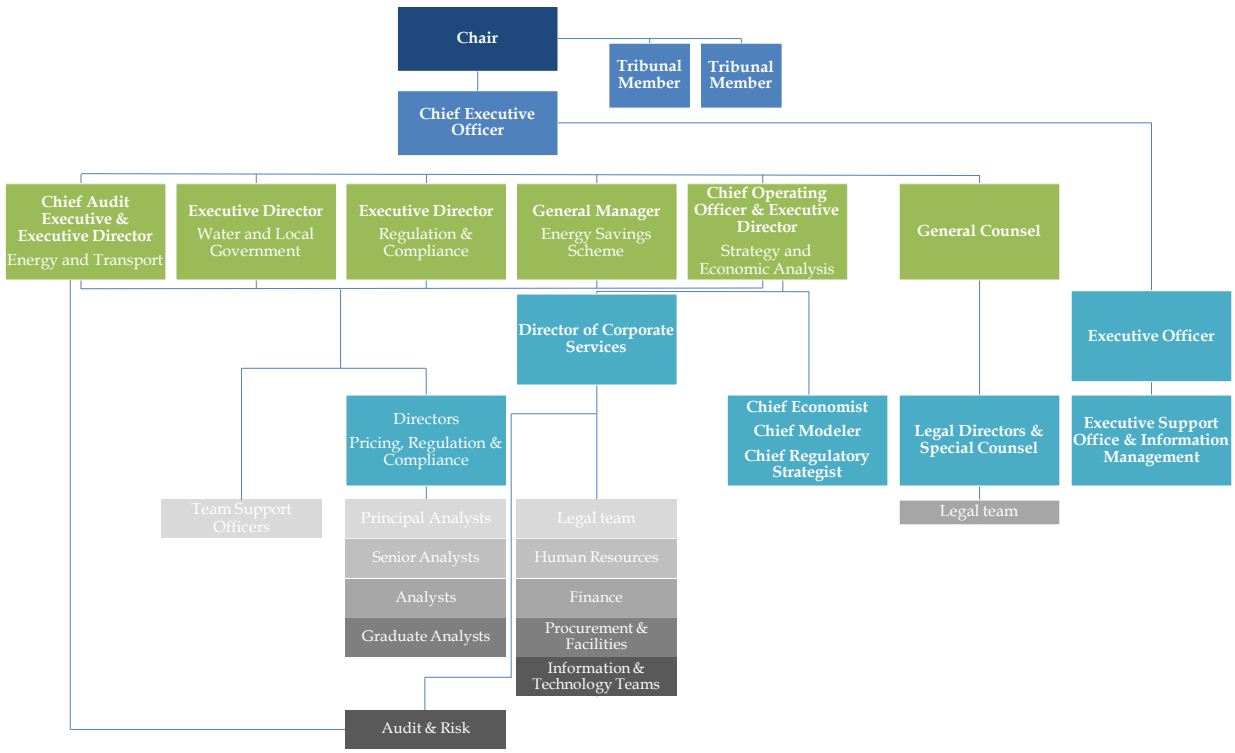
The Independent Pricing and Regional Tribunal ("IPART") is the provincial regulator responsible for the electricity, gas, water, and transport sectors, thereby serving the role of PUC in New South

[72] Alberta PUC. *Compensation Disclosure*. 2015 – 2017.

[73] The Project Team has sent the data request to the department but has not heard back from them yet.

Wales. Unlike the Hawaii PUC, IPART does not regulate the telecommunications sector. More specifically, IPART is responsible for the economic regulation of transmission and distribution networks within New South Wales. Under the *Electricity Supply Act 1995*, IPART is also responsible for setting retail tariffs, as well as monitoring electricity licenses in distribution and supply. [74] Figure 18 depicts the divisional structure of the IPART, consisting of divisions dedicated to Energy and Transport, Licensing and Compliance, Water Pricing, and Local Government, to name a few.

Figure 18. Organizational chart of the Independent Pricing and Regional Tribunal



Source: IPART Annual Report 2016-17.

The employment categories within the divisions, as well as the corresponding approximate number of staff and major background/expertise of said staff, are provided in Figure 19. While divisional staffing levels are not provided, Figure 18 shows that IPART has a division dedicated to compliance (i.e., Regulation & Compliance) like the Hawaii PUC (i.e., Consumer Affairs and Compliance). Both PUCs also have separate divisions for legal advisory (i.e., Commission Counsel in the Hawaii PUC and General Counsel in IPART), as well as for policy and economics research (i.e., Policy and Research in the Hawaii PUC and Strategy and Economic Analysis in IPART).

[74] NSW Government. Department of Premier and Cabinet. *Final Report of the Special Commission of Inquiry into the Electricity Transactions.* October 2011. p. 23.

Unlike the Hawaii PUC, however, IPART does not have a separate division for audit (i.e., the Audit Section in the Hawaii PUC); instead, Audit & Risk fall under Energy and Transport, as well as under the Director of Corporate Service (which in turn is under Strategy and Economic Analysis). Also, unlike the Hawaii PUC, the IPART has divisions dedicated to sectors, such as the Energy & Transport division and the Water & Local Government division.

Figure 19. Number of staff members in the employment category of IPART in 2016 and their major background/expertise

Employment category	Approximate # of Staff	Major background/expertise of Staff
Chair	1	management
Chief Executive	1	management, operations
Executive Directors & General Managers	6	management, executive assistance, daily operations
Chief Financial Officer & Director, HR	2	human resource management, operations
Directors	16	management, daily operations
Managers	4	management, daily operations
Analysts	77	project support, technical assistance, research, analysis
Graduate Analysts	3	project support, technical assistance, research, analysis
General Counsel	1	policy advisory
Director, Legal & Special Counsel	2	legal advisory, policy advisory, planning
Legal Officers	3	legal assistance, policy advisory
Support Officers	23	technical assistance, administration, information technology
Supernumeraries	12	*N/A*
Total	***151***	***N/A***

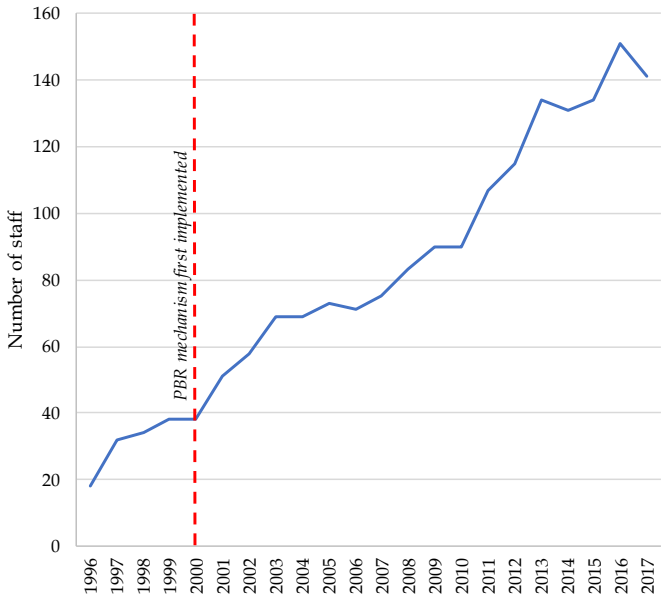
Note: The number of staff (i.e., a total of 151 employees) represent full-time, part-time, and temporary staff, as well as graduates. Tribunal members are not included.

Source: IPART Annual Report 2015-16.

As shown in Figure 19, IPART had a total of approximately 151 employees, including full-time, part-time, and temporary staff, as well as graduates in 2016 (not including Tribunal members), or 133 full-time equivalent employees. This number is over two times the staffing levels in the Hawaii PUC and the AUC, and similar to the staffing level in ICC.

The PBR mechanism for New South Wales was approved in 1999 and came into effect in 2000. As shown in Figure 20, the total number of staffing increased by 34% in 2001 (from 38 to 51), one year after the implementation of PBR. In 2002, the total staffing level increased further by 14% (from 51 to 58). Overall, total staffing levels have shown a generally increasing pattern since the adoption of PBR in 2000, with minor drops in 2006, 2014, and 2017, most likely due to retirements. This could mean that the implementation of the Conventional PBR with Light HERA model may increase the staffing levels required in the Hawaii PUC.

Figure 20. IPART's staffing levels before and after PBR signed into law



Note: The numbers above reflect the total headcount, not full-time equivalents. Put differently, the staffing level depicted above is comprised of full-time, part-time, and temporary staff, as well as graduates. Full-time equivalents are not provided in IPART Annual Reports prior to 2015.

Source: IPART Annual Reports (1995-2017)

5.2.2.2 DCA

Malaysia

Malaysia does not have a separate consumer advocate office. "*Balancing the needs of consumers and providers of energy*" and "*protecting public interest*" are parts of the mission of Malaysia ST.[75]

Alberta

Like the Hawaii DCA, the Office of the Utilities Consumer Advocate ("UCA") represents the interests of electricity and natural gas consumers in Alberta. The UCA is formed under the *Government Organization Act*, Schedule 13.1 and has three core functions, including education, advocacy, and mediation.[76]The change in the number of staff members and their background/ expertise are not publicly available.[77]

New South Wales

[75] Malaysia ST. *Vision, Mission and Core Values*. Web. <http://www.st.gov.my/index.php/en/about-us2/vision-mission-and-core-values>.

[76] UCA. *Annual Report to the Minister 2016-2017*. October 16, 2017.

[77] The Project Team has sent the data request to the department but has not heard back from them yet.

The Energy & Water Ombudsman NSW ("EWON") is New South Wales' government-approved "*dispute resolution scheme*" for gas and electricity residential and small business customers, as well as some water residential and small business customers.[78,79] It was founded in 1998 as an independent service to help customers settle complaints with their respective providers. Both IPART and AER have signed a memorandum of understanding with EWON. In 2016/2017, EWON's structure was "*streamlined into four core teams working under the leadership of the Ombudsman*," namely People; Finance & Corporate Services; Investigations; and Governance, Awareness & Policy, as shown in Figure 21.[80] The number of staff members in EWON are not publicly available.[81]

Figure 21. Description of divisions and required expertise of staff members in EWON

Divisions	Description of Divisions	Major background/expertise of Staff
People	responsible for maximizing staff engagement and contribution, and develops HR strategy	human resources, development
Finance & Corporate Services	manages financial reporting, ICT infrastructure and service delivery, and general administraion and facility management	data analysis, information technology, finance, coordination
Investigations	handles customer complaints against providers, including receiving, assessing, investigating, and reviewing complaints	research, case review, assessment, resolution
Governance, Awareness & Policy	oversees governance, quality, member relations, communication, community outreach, and policy functions	policy, research, quality assurance, community engagement, communications

Source: EWON Annual Report 2016/2017

5.2.3 The Hybrid model

As discussed in the deliverables for Task 2.1.1 and 2.2.2, currently, no jurisdiction has a full-blown distribution-focused regulatory model. LEI focused on the example of New York since it is in the process of moving toward this model via REV. The REV initiative is aimed at fundamentally shifting the role of the utility from an entity that develops and maintains transmission and distribution assets[82] to an entity that enables the localized management of electricity supply and demand. In addition, under REV, outcome-based earning opportunities will be added to the traditional ratemaking approach. Moreover, it has an ISO, which is similar to what is proposed for the independent grid operator. Admittedly, it is not the same as the Hybrid model that we proposed for Hawaii. However, this case serves as a good reference in assessing the impact of a

[78] "About us." *Energy & Water Ombudsman NSW*. Web. September 6, 2018. < https://www.ewon.com.au/page/about-us>

[79] "Our History." *Energy & Water Ombudsman NSW.* Web. September 6, 2018. < https://www.ewon.com.au/page/about-us/our-history#founded>

[80] EWON. *Annual Report 2016/2017.*

[81] The Project Team has sent the data request to the department but has not heard back from them yet.

[82] Utilities in New York generally are not allowed to own generation assets.

similar hybrid model to the staffing of relevant State agencies. Further details such as the overview of the market, its regulatory framework, and the recent developments of REV in New York can be found in Task 2.2.2 (Assessment of current markets under each regulatory model).

Overall, the jurisdiction selected (i.e., New York) for the hybrid model has currently more staff in its PUC compared to that of the Hawaii PUC. Staffing levels for its version of Hawaii's DCA (i.e., the Utility Intervention Unit subdivision under the Consumer Protection division of the Department of State in New York) were not available. On average, the representative state had approximately 19 staff per 100,000 customers in 2016, slightly higher than the staff-to-customers ratio in Hawaii as of 2016 (i.e., 17 staff per 100,000 customers).

Figure 22. Staff-to-customers ratio in New York compared to Hawaii

Number of staff : 100,000 customers

	Status quo	The Hybrid Model
	HI	New York
PUC	12.8	18.9

Note: 2016 numbers were utilized for the purposes of consistent comparison.

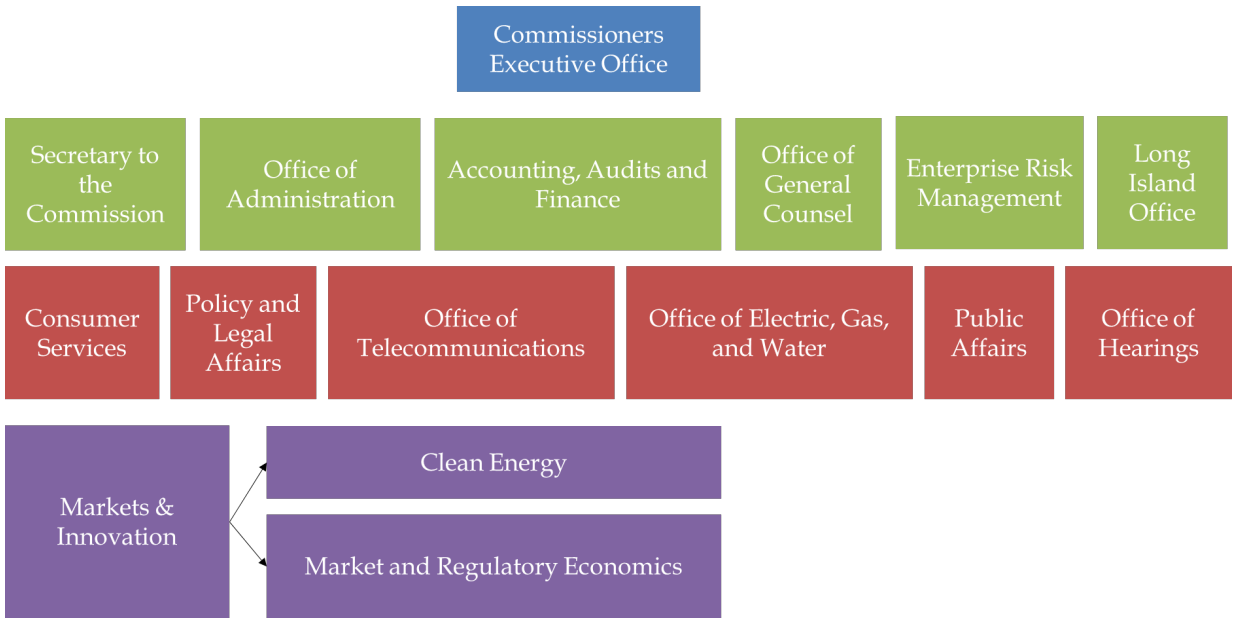
Source: HI PUC. NYPSC Executive Budget 2015/16.

5.2.3.1 PUC

Similar to the Hawaii PUC, New York Public Service Commission ("NY PSC") regulates the electric, gas, steam, telecommunications, and water utilities in the state. In addition, the PSC also oversees the cable industry. As the staff arm of the PSC, the Department of Public Service ("DPS") has a broad mandate to "*ensure access to safe, reliable utility service at just and reasonable rates*."[83] The DPS is organized into 14 offices, as shown in Figure 23.

Figure 23. Indictive organizational chart of New York PSC

[83] "About DPS." *NY DPS*. Web. <*http://www3.dps.ny.gov/W/PSCWeb.nsf/All/78F051A24B026591852576A5006D5163?OpenDocument*>. Access date: August 24, 2018.



Note: this chart is indicative only, as the official organization chart is not publicly available; color coding is added by LEI: green - departments dealing with PSC internal affairs, red - departments dealing with consumers or external entities, purple - departments highly related to regulatory changes

Source: NY DPS. Directory of Offices.

These 14 offices have different functions and require staff to have different background and expertise. These background and expertise are listed in Figure 24. Similar to the Hawaii PUC, the NY PSC has separate divisions that are responsible for auditing, consumer affairs, administrative services, and policy and research, etc. In addition, the NY PSC has some sectors-focused divisions that the Hawaii PUC does not have, including the Office of Telecommunications and the Office of Electric, Gas, and Water. Moreover, some functional divisions that the NY PSC has also does not exist in the Hawaii PUC, like Enterprise Risk Management, Office of Hearings, and Markets & Innovation, to name a few.

It is worth noting that the Markets & Innovation division which focuses on clean energy and market oversight did not exist prior to 2014.[84] Its formation might be relevant to the REV initiative, while in Hawaii, the Hawaii State Energy Office takes the role of leading the state's change toward clean energy independence.[85] If the Hawaii PUC set up a similar division that

[84] The Markets & Innovation division was not listed on the web page on NY DPS which was updated by September 2013. Source: NY DPS. Web. <*http://www3.dps.ny.gov/W/PSCWeb.nsf/All/78F051A24B026591852576A5006D5163?OpenDocument*>. Access date: August 24, 2018.

[85] "Who we are." *Hawaii State Energy Office*. Web. < http://energy.hawaii.gov/who-we-are>. Access Date: September 11, 2018.

focuses on the transition to the hybrid regulatory model, staff members that have experience with regulatory transitioning will be needed in this division.

Under REV, the NY PSC plays a critical role in crafting the significant regulatory changes needed to make the Governor's agenda a reality.[86] The NY PSC takes the responsibility of "*aligning markets and the regulatory landscape with the overarching state policy objectives of giving all customers new opportunities for energy savings, local power generation, and enhanced reliability to provide safe, clean, and affordable electric service.*"[87] Under the REV proceeding (Case number 14-M-0101), there are approximately 1,500 filed documents, 7,800 public comments, and 290 stakeholders included in the party list.[88] In addition, under this proceeding, two REV working groups were set up under Track 1, and both of them were convened by the NY DPS staff together with stakeholders.[89] Obviously, the transition under the REV model increased the workload for the NY PSC significantly, and transition to a Hybrid model would potentially have similar impacts on the Hawaii PUC as well.

Figure 24. Description of divisions and required expertise of staff members

Divisions	Description of divisions	Major background/ expertise of Staff
Executive Office	senior management of the organization and relevant support	management, development, administration
Policy and Legal Affairs	special counsel and senior policy advisor regarding strategic planning; make recommendations to the Commission on policy, regulatory, and legal matters	expertise in policy, regulatory, and legal matters
Secretary to the Commission	maintaining the records of the proceedins with the DPS; coordination of the components of proceedings; etc.	administration, documentation, clercial services, knowledge of ethical responsibilities as employees, etc.
Public Affairs	an advocate for the utility regulatory policies, programs, and initiatives; an integrated internal and external communications program	communications, public relations
Long Island Office	examining the core utility operations of PSEG Long Island, and advising the Long Island Power Authority	operations of utilities
Office of Administration	consisting of three sections including the Human Resources Management section, the Administrative Management section, and the Finance and Budget section	recruitment, human resources, administrative management, fiscal, and budgeting

[86] "About the Initiative." *New York State - DPS*. Web. <http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument>. Access Date: September 11, 2018.

[87] Ibid.

[88] "Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision." *NY PSC*. Web. <http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101&submit=Search+by+Case+Number>. Access Date: September 11, 2018.

[89] "Working Groups." NY DPS. Web. <http://www3.dps.ny.gov/W/PSCWeb.nsf/All/D437F88969CCD2F985257CD20066552A?OpenDocument>. Access Date: September 11, 2018.

Consumer Services	representing consumer for all activities overseen by the Commission, taking and resolving consumer complaints and utilizing consumer input to develop consumer policy	consumer engagement, facilitation, and communications, etc.
Markets & Innovation	clean energy initiatives, market analytics and oversight	analysis, economics, research, project management, rate design, etc.
Enterprise Risk Management	identifying particular events or circumstances (risk and opportunities) relevant to the organization's objectives, assessing and addressing risks and opportunities, internal auditing	analysis, research, auditing and monitoring
Office of General Counsel	legal representation and advice; representing on behalf of the people of the state in all actions and proceedings, preparing proposed regulations and legislation, etc.	legal advisory, testimony
Office of Hearings	hearings, legal assistance, mediators in assisting parties in settlement negotiations	legal assistance
Office of Telecommunications	overseeing the performance of the telecommunication and cable television companies	knowledge about telecommunication systems, technical and safety standards
Office of Electric, Gas, and Water	focusing on utility rates and services	knowledge about utilities, system planning and operations, tariff and rates, transmission and generation siting, etc.
Accounting, Audits and Finance	performing financial audits and examinations relative to utility rate changes, mergers and acquisitions, fuel clause operations, prudence reviews, and state and federal tax changes	financial auditing, accounting

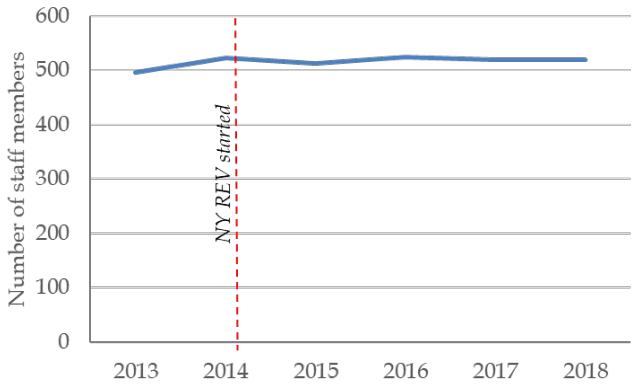
Note: staff number under each department is not publicly available

Source: NY DPS. Directory of Offices.

As shown in Figure 25, the number of staffing increased by 5% (from 496 to 523) in 2014 when Governor Cuomo initiated the REV, which might be part of the preparation for the REV. Since then, the total staffing level has not changed much in the past few years.[90] Moreover, in terms of staff level (instead of ratio), the NY PSC already has around 500 staff members before the implementation of the REV, so the need of adding additional staff might be less significant than the Hawaii PUC which only has 65 staff members. This implies that more staffing members are required in the Hawaii PUC if the regulatory model in Hawaii will be changed to a Hybrid model that is similar to the REV in terms of complexity.

[90] "Public Service Department - Budget Highlights." *New York State*. Web. <https://www.budget.ny.gov/pubs/archive/fy17archive/eBudget1617/agencyPresentations/appropData/PublicServiceDepartment.html>. Access date: August 24, 2018.

Figure 25. New York PSC's staffing levels before and after implementation of REV



Note: 2018 number was estimated by New York State in 2017

Source: NY DPS. Executive Budget (2013 - 2017)

5.2.3.2 DCA

Similar to Hawaii, there is a separate entity that advocates for consumers' interests before the PSC in New York. Under the Consumer Protection division of the Department of State in New York, there is a Utility Intervention Unit subdivision, which "*actively participates in proceedings concerning the availability, pricing, and quality of electricity and natural gas service*." Like the DCA in Hawaii, experts in this Utility Intervention Unit "*submits formal filings commenting on proposals by utilities or regulators*" and "*testify before the PSC in natural gas and electricity delivery rate proceedings involving major utilities*."[91] However, data of staffing members of this subdivision is not publicly available.[92]

[91] "Utility Intervention." *Department of State*. Web. <https://www.dos.ny.gov/consumerprotection/reports/energy_utility_intervention/index.html>. Access date: August 24, 2018.

[92] The Project Team has sent the data request to the department but has not heard back from them yet.

6 Appendix A: Scope of work to which this deliverable responds

Task 2.3.4 Assessment of how each ownership model impacts staffing of State agencies and stakeholders such as the Public Utilities Commission and the Consumer Advocate similar to analysis conducted in TASK 1.3.4. CONTRACTOR shall provide an estimate of the potential impacts a change in regulatory model may have on the expertise and staffing requirements of related State agencies and stakeholders (e.g., PUC, Consumer Advocate).

DELIVERABLE FOR TASK 2.3.4. CONTRACTOR shall provide its conclusions and all work to assess how the regulatory model could impact state agencies and stakeholders such as the Public Utility Commission and the Consumer Advocate, similar to the analysis conducted on ownership models in TASK 1.3.4. CONTRACTOR shall analyze best practices in terms of staffing and expertise at public utility commissions, state energy offices, consumer advocate offices, and other relevant state agencies across a broad array of jurisdictions. CONTRACTOR shall identify at least three to five jurisdictions for each regulatory model, with staffing at their relevant state energy agencies, including the utility commissions. CONTRACTOR shall utilize high-level data, such as total staffing, from websites or in annual reports, along with the results of interviews to understand specific expertise required. CONTRACTOR shall provide a written description of the analysis in MS Word, include an overview MS Excel table listing total staffing in each jurisdiction assessed, include a breakdown for functional expertise and show an average for each of the regulatory models. CONTRACTOR shall submit deliverable for TASK 2.3.4 to the STATE for approval.

7 Appendix B: Works Cited

"About DPS." *NY DPS*. Web. <*http://www3.dps.ny.gov/W/PSCWeb.nsf/All/78F051A24B026591852576A5006D5163?OpenDocument*>. Access date: August 24, 2018.

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Estimate of book value for existing facilities in each county

working paper prepared by London Economics International LLC for the Hawaii Department of Business Economic Development and Tourism

January 26th, 2018

London Economics International LLC, together with Meister Consultants Group ("the Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State of Hawaii in achieving its energy goals. As part of the engagement, this working paper provides a substantive estimate of the book value (original cost minus depreciation) for existing facilities necessary to provide electric service in each county. Hawaiian Electric Company ("HECO") has the highest book value among the utilities in the state, with a total asset net book value of $2,611.4 million as of June 30, 2017. Hawaii Electric Light Company ("HELCO") and Maui Electric Company's ("MECO") assets respectively total $660.0 million and $607.4 million for the same period, while KIUC's assets total $244.7 million as of December 31, 2016.

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List of acronyms

DBEDT	Hawaii Department of Business, Economic Development, and Tourism
FERC	Federal Energy Regulatory Commission
HECO	Hawaiian Electric Company, Inc.
HEI	Hawaiian Electric Industries, Inc.
HELCO	Hawaii Electric Light Company, Inc.
HPUC	Hawaii Public Utility Commission
HSEO	Hawaii State Energy Office
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company, Ltd.
USOA	Uniform System of Accounts
NARUC	National Association of Regulatory Utility Commissioners
PHFFU	Property Held for Future Use

1 Executive summary

London Economics International LLC, together with Meister Consultants Group (the "Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which corresponds to Task 1.4.1 in the project scope of work, provides a substantive estimate of the book value (original cost less depreciation) of the existing facilities that would need to be acquired to provide electric service in each county.

1.1 Introduction to book value

The book value for any type of asset is the value at which it is carried on a company's balance sheet or financial statements. It is calculated as the asset's original cost minus the accumulated depreciation, which represents the decreasing value of life-limited assets as they age.

All utilities in the state of Hawaii have commissioned depreciation studies to determine appropriate depreciation rates for their production, transmission, distribution, and general category assets. All utilities rely on a straight-line method and remaining life technique to develop the annual depreciation accrual rates; this technique provides for the recovery of the undepreciated original cost of property, adjusted for net salvage, over the remaining life of the property.

1.2 Book value estimate for the utilities' assets

The Project Team examined each county's electric utility regulatory filings and financial statements to estimate the net book value of assets required to provide electrical service.

Figure 1. Net book value for utility assets necessary to provide electric service in the State of Hawaii

$ thousands	HECO	HELCO	MECO	KIUC
Cost	4,362,431	1,273,720	1,128,445	515,881
Accumulated Depreciation	(1,750,994)	(613,768)	(521,055)	(271,185)
Net Book Value	2,611,437	659,952	607,390	244,696

Source: HECO, HELCO, MECO, KIUC annual reports; HECO Companies responses to LEI data requests

As shown in Figure 1, HECO has the highest book value among utilities in the State, with a total asset net book value of $2,611.4 million as of June 30, 2017. HELCO and MECO's assets respectively total $660.0 million and $607.4 million for the same period, while KIUC's assets total $244.7 million as of December 31, 2016.

For all utilities, transmission and distribution assets are the major categories of assets in terms of original cost, representing more than 50% of the original cost of plants in service. Production assets comprise all structures and equipment related to power generation, and for all utilities represent approximately a quarter of the original cost of plants in service. Finally, other asset

categories worth mentioning include general category assets (mostly office space and furniture, transportation equipment, communication equipment, and other miscellaneous items) as well as land.

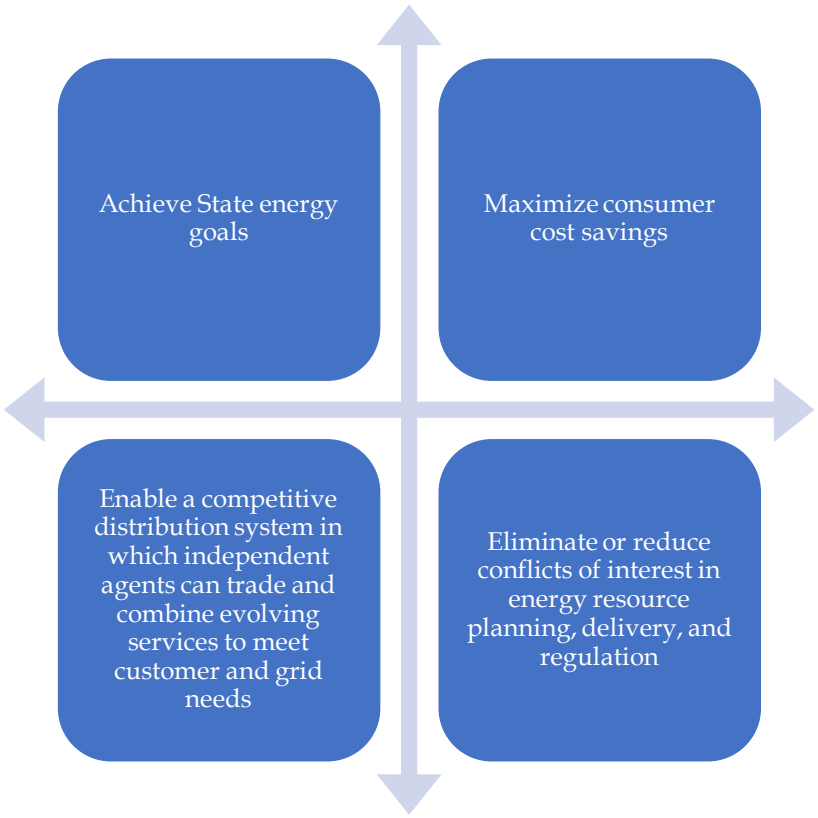
2 Introduction and scope

2.1 Project description

DBEDT was directed by the State's legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. The Project Team, through a competitive sealed proposals procurement,[1] was contracted to perform this study.[2]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[3] listed in Figure 2.

Figure 2. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

[1] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[2] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[3] House Bill No. 1700 Relating to the State Budget.

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[4]

2.2 Role of this deliverable relative to others in the project

This deliverable corresponds to Task 1.4.1 in the project scope of work. It provides quantitative estimates of the book value for existing facilities that would need to be acquired to provide electrical services in each county of Hawaii. These assets include existing production, transmission, distribution, general category, and other types of assets. The Project Team relied on regulatory filings, annual reports, and other corporate financial documents from the utilities in order to compile this estimate of each utility's assets book value.

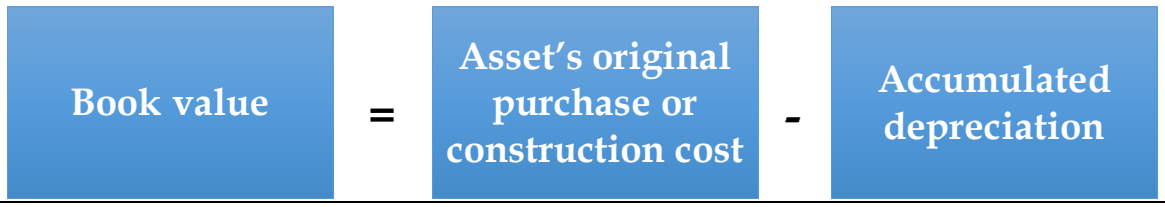
[4] Hawaii Contract No. 65595. Scope of Services.

3 Introduction to book value

In this document, the Project Team summarizes the book value estimates of all current facilities that are used by the existing utilities to provide electrical service in each county. Existing utilities are all of the Hawaiian Electric companies including Hawaiian Electric Company ("HECO"), Maui Electric Company ("MECO"), and Hawaii Electric Light Company ("HELCO") (collectively "the HECO Companies"), as well as the Kauai Island Utility Cooperative ("KIUC").

The book value of any type of asset is the value at which it is carried on a company's balance sheet or financial statements. It is calculated as the asset's original cost minus the accumulated depreciation. The results include the sum of book value for these companies' tangible assets and do not deduct liabilities, so as to represent the current accounting value of each company's assets.

Figure 3. Book value formula



3.1 Asset categories for power utilities

Power utility assets are reported to regulatory bodies following the Uniform System of Accounts ("USOA"), which has been established by the National Association of Regulatory Utility Commissioners ("NARUC") and Federal Energy Regulatory Commission ("FERC") to prescribe accounting classifications and instructions to achieve uniform accounting records. The USOA provides basic account descriptions, instructions, and accounting definitions that are useful in understanding the information reported in various FERC-mandated report forms.[5]

Of particular interest for this task are the 300 series of accounts (see Figure 4), which include all-electric plant accounts such as:

1. Intangible Plant;
2. Production Plant;
3. Transmission Plant;
4. Distribution Plant;
5. Regional Transmission and Market Operation Plant; and
6. General Plant.

[5] FERC, "Uniform System of Accounts", web. <https://www.ferc.gov/enforcement/acct-matts/usofa.asp>

Figure 4. USOA Account numbering

Account number range	Category Description
100s	Assets
200s	Liabilities and Capital
300s	Detailed Plant Accounts
400s	Operating Revenues, Other Income & Income Deduction Accounts
500s	Electric Expense Accounts & Wastewater Revenue Accounts
600s	Water Expense Accounts including General
700s	Gas Production Expense Accounts and Wastewater Expense Accounts
800s	Gas Expense Accounts
900s	General Expense Accounts

Source: NARUC, "US Regulatory Accounting System. Web. <https://pubs.naruc.org/pub.cfm?id=538932FA-2354-D714-51DD-1C253F7DA53F>

Throughout this document, the Project Team breaks down the book value estimates for the utilities' assets by account number, to reflect publicly available information that has been submitted by the utilities to the Hawaii Public Utilities Commission ("PUC").

3.2 General principles of book value calculation

An asset's initial book value represents the original cost of construction or acquisition. For assets such as buildings and equipment, construction costs include the cost of contracted services, direct labor, materials, and overhead items such as costs tied to the purchase of the asset.[6]

Periodic depreciation, amortization, and depletion can be used to reduce the book value of assets over time, for instance, to represent the decreasing value of life-limited assets as they age. Depreciation is used to record the declining value of buildings and equipment over time. Land is not depreciated. Amortization is used to record the declining value of intangible assets such as patents. Depletion is used to record the consumption of natural resources.[7] The book value of an asset is the asset's initial cost basis minus accumulated depreciation, amortization or depletion.

The FERC USOA includes the following definition for depreciation:

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[6] SAIC, "2012 Depreciation Study – KIUC", August 2013. Filed on May 8, 2015 in Docket 2015-0127 as Exhibit 2 of KIUC's "Petition for Declaratory Ruling"

[7] H.L. Wolk, J.L. Dodd, and M.G. Tearney. "Accounting Theory: Conceptual Issues in a Political and Economic Environment", 6th ed. South-Western., 2004, pp. 330-331

> "Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, and changes in the demand and requirements of public authorities."[8]

When an asset is retired, replaced, or removed from service, the average cost of the asset as determined from the continued property record is removed from the total sum of original value, and such cost, together with the cost of removal less salvage, is also removed from the accumulated provision for depreciation.

The depreciation, amortization, or depletion rate is calculated as the percent rate at which an asset is depreciated in any one of the methods for computing depreciation. In its simplest form, it is computed by dividing the depreciable cost of the asset by the number of years in (or by the number of units of output or usage during) the asset's estimated productive or useful life. The annual depreciation expense represents the product of the original cost and the calculated rate.

3.2.1 Depreciation rates calculation

The HECO Companies and KIUC currently calculate their depreciation expense accrual as the sum of the depreciation and amortization for all applicable USOA accounts. The annual depreciation expense for each account is calculated by multiplying the approved depreciation or amortization rate for the account by the beginning of the year plant-in-service balance for the account.[9]

The HECO Companies and KIUC have commissioned depreciation studies to determine appropriate depreciation rates for the utilities' production, transmission, distribution, and general plant accounts. All utilities rely on a straight-line method and remaining life technique to develop the annual depreciation accrual rates. The remaining life technique provides for the recovery of the undepreciated original cost of property, adjusted for net salvage, over the remaining life of the property. The analyses conducted in the depreciation study use historical service life and salvage data in estimating survivor curves, service lives, remaining lives, and net salvage estimates. The historical experience analysis ensures that the historical characteristics used to calculate the depreciation rates are applicable to surviving property. [10]

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[8] R.L. Hahne and G.E. Aliff. "Accounting for Public Utilities", LexisNexis, 1983, page 101

[9] HECO, "HECO Direct Testimonies and Exhibits", HECO-202, Docket 2010-0053, March 30, 2010.

[10] *Ibid.*; SAIC, "2012 Depreciation Study – KIUC", August 2013. Filed on May 8, 2015 in Docket 2015-0127 as Exhibit 2 of KIUC's "Petition for Declaratory Ruling"

Survivor curves

The Survivor Curve method is used to estimate the average service life and remaining life for accounts consisting of a large number of property units that, even though similar, retire independent of each other at different ages. Survivor curves are used to show the statistical dispersion or frequency of retirements throughout the life of the property. A survivor curve can be depicted by a graph showing the number or percentage of units surviving at the beginning of each age interval. The most well-known and generally accepted survivor curves are the Iowa Survivor Curves developed at Iowa State University.

Source: SAIC, "2012 Depreciation Study – KIUC", August 2013. Filed on May 8, 2015, in Docket 2015-0127 as Exhibit 2 of KIUC's "Petition for Declaratory Ruling"

Any proposed changes in the depreciation and amortization rates and periods, as applicable, by regulated utilities must be approved by the PUC. In accordance with past decisions and orders,[11] regulated utilities are required to file depreciation studies on a regular basis, not to exceed five years from the date the PUC approves new depreciation rates, unless there are compelling reasons for different intervals. The Commission's determination includes the review of the procedures for calculating the depreciation and amortization rates and periods, the study calculating the rates, and the effective date of implementation of the changes in rates.

Furthermore, the Agriculture Rural Utilities Service ("RUS"), as KIUC's primary lender, has extensive rights to oversee many aspects of KIUC's business. As part of this oversight, RUS requires KIUC to periodically conduct depreciation studies to review the reasonableness of KIUC's depreciation rates. Furthermore, KIUC is prohibited from adopting depreciation rates that have not been previously approved for KIUC by RUS.[12]

RUS reviews its borrowers' depreciation studies and approves its borrowers' depreciation rates to ensure that the procedure used to estimate the lives of the assets is adequate and that the estimated lives of the assets are accurate. This review is very similar to the PUC review of proposed depreciation and amortization rates. Considering that RUS has jurisdiction over and conducts a thorough review of KIUC's depreciation rates, KIUC has petitioned the PUC to argue that it should not be required to obtain PUC approval to change its depreciation rates. The docket is still open as the PUC has not yet issued a decision.[13]

[11] PUC Dockets 2010-0053 (HECO); 2009-0321 (HELCO); 2009-0286 (MECO); 2011-0128 (KIUC).

[12] KIUC, "Petition for Declaratory Ruling", PUC Docket 2015-0127, May 8, 2015.

[13] *Ibid*

4 Book value estimate for existing Hawaii power utility facilities

The Project Team examined each county's electric utility regulatory filings and financial statements to estimate the net book value of assets required to provide electrical service.

Figure 5. Net book value for utility assets necessary to provide electric service (As of June 30, 2017, for HECO Companies and December 31, 2016, for KIUC)

$ thousands	HECO	HELCO	MECO	KIUC
Cost	4,362,431	1,273,720	1,128,445	515,881
Accumulated Depreciation	(1,750,994)	(613,768)	(521,055)	(271,185)
Net Book Value	2,611,437	659,952	607,390	244,696

As shown in Figure 5, HECO has the highest book value among utilities in the State, with a total asset book value of $2,611.4 million. HELCO and MECO's assets respectively total $660.0 million and $607.4 million, while KIUC's assets total $244.7 million.

4.1 HECO

As of June 30, 2017, HECO reported a total net book value (original cost minus accumulated depreciation) for its assets on Oahu Island of $2,611.4 million, as illustrated in Figure 6.

Figure 6. HECO assets net book value as of June 30, 2017

$ thousands	Production	T & D	General	Land	Tenant Allowance	Total
Cost	992,293	2,954,735	357,374	43,971	14,058	4,362,431
Accumulated Depreciation	(357,696)	(1,241,203)	(143,973)	0	(8,122)	(1,750,994)
Net Book Value	**634,597**	**1,713,532**	**213,401**	**43,971**	**5,936**	**2,611,437**
Percent depreciated	**36%**	**42%**	**40%**	**0%**	**58%**	**40%**

Source: HECO Companies response to LEI data request

The largest share of assets in terms of value is in the Transmission and Distribution category, representing $1,714.5 million or 65.6% of the total net book value of the company's assets. Production assets are valued at $634.6 million, or 24.3% of the total value. Other assets, including the General, Land, and Tenant Allowance[14] categories, total $263.3 million or 10.1% of the total net asset value.

[14] Tenant allowances can include incentives offered in the form of free or reduced rent, or up-front payments for items like moving expenses or improvements needed to customize a rental.

4.1.1 Production assets

The original cost of HECO's production assets represents $992.3 million, with $783.4 million worth of property in the Steam Production Plant category and $208.8 million in the Other Production Plant category (this category includes HECO's diesel and fuel oil combustion turbines).

Figure 7. HECO production assets by category

PRODUCTION PLANT		Original Cost ($ thousands)	Avg Service Life (years)	Depreciation Rate	Amortization Rate
Steam Production Plant					
311	Structures and Improvements	96,421	54	1.60%	-
312	Boiler Plant Equipment	392,071	47	2.03%	-
313	Engines and Engine-Drive Generators	-	-	-	-
314	Turbogenerator Units	189,998	51	1.54%	-
315	Accessory Electric Equipment	80,971	44	2.43%	-
316	Misc. Power Plant Equipment	23,984	20	-	5.00%
317	Asset Retirement Costs for Steam Production	-	-	-	-
Total Steam Production Plant		**783,445**			
Other Production Plant*					
341	Structures and Improvements	38,507	53	0.77%	-
342	Fuel Holders, Products, and Accessories	16,598	39	2.58%	-
343	Prime Movers	68,247	48	3.26%	-
344	Generators	32,457	51	1.01%	-
345	Accessory Electric Equipment	34,059	46	2.51%	-
346	Misc. Power Plant Equipment	18,979	20	-	5.00%
347	Asset Retirement Costs for Other Production	-	-	-	-
Total Other Production Plant		**208,847**			
Total Production Plant		**992,293**			

* Other production plants include all plants other than steam, nuclear, and hydraulic production plants

Source: HECO 2016 annual report; HECO Companies response to LEI data request

The average service life of structures is estimated at over 50 years, while most of the equipment associated with electrical generation has an estimated service life ranging from 39 to 51 years depending on the category. The corresponding depreciation rates, which combine each asset categories' capital recovery rate and adjustments for salvage rates and cost of removal rates, are shown in Figure 7.

4.1.2 Transmission & distribution assets

HECO's transmission assets represent a total original value of $1,018.0 million as of June 30, 2017, with the largest categories of assets being station equipment, poles and fixtures, and overhead conductors. The average service life for all transmission assets ranges from 50 to 60 years. The corresponding depreciation rates are shown in Figure 8.

Figure 8. HECO transmission assets by category

	TRANSMISSION PLANT	Original Cost ($ thousands)	Avg Service Life (years)	Depreciation Rate	Amortization Rate
352	Structures and Improvements	61,525	55	1.60%	-
353	Station Equipment	312,271	60	1.86%	-
354	Towers and Fixtures	15,768	60	1.48%	-
355	Poles and Fixtures	328,950	50	3.24%	-
356	Overhead Conductors and Devices	167,960	50	3.27%	-
357	Undergorund Conduit	62,827	60	1.59%	-
358	Underground Conductors and Devices	65,340	60	1.73%	-
359	Roads and Trails	3,315	60	1.49%	-
Total Transmission Plant		**1,017,957**			

Source: HECO 2016 annual report; HECO Companies response to LEI data request

HECO's distribution assets represent a total original value of $1,936.89 million as of June 30, 2017, or almost twice the value of the transmission assets. The largest categories of assets are associated with underground conductors and conduits. The average service life for all distribution assets ranges from 50 to 65 years, except for meters (32 years) and line transformers (30 years). The corresponding depreciation rates are shown in Figure 9.

Figure 9. HECO distribution assets by category

	DISTRIBUTION PLANT	Original Cost ($ thousands)	Avg Service Life (years)	Depreciation Rate	Amortization Rate
361	Structures and Improvements	22,967	65	1.08%	-
362	Station Equipment	256,831	55	2.02%	-
363	Storage Battery Equipment	-	-	-	-
364	Poles, Towers, and Fixtures	217,323	50	3.34%	-
365	Overhead Conductors and Devices	123,273	50	4.19%	-
366	Underground Conduit	316,345	60	2.19%	-
367	Underground Conductors and Devices	452,228	51	4.98%	-
368	Line Transformers	238,232	30	5.20%	-
369.1	Services - Overhead	270,782	55	5.25%	-
369.2	Services - Underground		60	4.07%	-
370	Meters	38,796	32	2.68%	-
Total Distribution Plant		**1,936,778**			

Source: HECO 2016 annual report; HECO Companies response to LEI data request

4.1.3 Other assets

HECO's other assets required to provide electrical service on Oahu island include office space and furniture, transportation equipment, communication equipment, and other miscellaneous items. The total original cost for these assets is $357.4 million as of June 30, 2017. The corresponding depreciation rates are shown in Figure 10.

Figure 10. HECO general assets by category

	GENERAL PLANT	Original Cost ($ thousands)	Avg Service Life (years)	Depreciation Rate	Amortization Rate
390	Structures and Improvements	91,561	50	2.45%	-
391.1	Office Furniture and Equipment - Information System Equipment	48,398	5	-	20.00%
391.2	Office Furniture and Equipment - Data Handling Equipment		10	-	10.00%
391.3	Office Furniture and Equipment		15	-	6.67%
392	Transportation Equipment	56,800	15	6.13%	-
393	Stores Equipment	1,352	25	-	4.00%
394	Tools, Shop and Garage Equipment	32,726	25	-	4.00%
395	Laboratory Equipment	660	15	-	6.67%
396	Power Operated Equipment	15	18	-	5.56%
397	Communication Equipment	117,675	15	-	6.67%
398	Miscellaneous Equipment	8,188	15	-	6.67%
Total General Plant		**357,374**			

Source: HECO 2016 annual report; HECO Companies response to LEI data request

4.2 HELCO

As of June 30, 2017, HELCO reported a total net book value (original cost minus accumulated depreciation) for its assets on Hawaii Island of $660.0 million, as illustrated in Figure 11.

Figure 11. HELCO assets net book value

$ thousands	Production	T & D	General	Land	PHFFU	Total
Cost	327,478	851,660	88,391	5,426	765	1,273,720
Accumulated Depreciation	(139,326)	(446,867)	(27,575)	0	0	(613,768)
Net Book Value	**188,152**	**404,793**	**60,816**	**5,426**	**765**	**659,952**
Percent depreciated	**43%**	**52%**	**31%**	**0%**	**0%**	**48%**

Source: HECO Companies response to LEI data request

As for HECO, HELCO's largest share of assets in terms of value are in the Transmission and Distribution category, representing $404.8 million or 61.3% of the total net book value of the company's assets. Production assets are valued at $188.2 million, or 28.5% of the total value. Other assets, including the General, Land, and Property Held for Future Use ("PHFFU") categories, total $67.0 million or 10.2% of the total net asset value.

4.2.1 Production assets

The original cost of HELCO's production assets represents $327.5 million, or approximately a third of HECO's production assets. The share of HELCO's steam production assets is $145.2 million, while its hydro assets have a total original value of $9.4 million. HELCO's other

production assets, which include its combustion turbines and internal combustion engines, total $172.9 million.

Figure 12. HELCO production assets by category

PRODUCTION PLANT		Original Cost ($ thousands)	Avg Service Life (years)	Depreciation Rate	Amortization Rate
Steam Production Plant					
311	Structures and Improvements	18,378	40	2.90%	-
312	Boiler Plant Equipment	68,074	34	3.08%	-
313	Engines and Engine-Drive Generators	-	-	-	-
314	Turbogenerator Units	47,820	35	2.54%	-
315	Accessory Electric Equipment	8,940	32	3.35%	-
316	Misc. Power Plant Equipment	2,001	20	-	5.00%
317	Asset Retirement Costs for Steam Production	-	-	-	-
Total Steam Production Plant		**145,214**			
Hydraulic Production Plant					
331	Structures and Improvements	97	65	0.94%	-
332	Resevoirs, Dams, and Waterways	6,189	50	2.03%	-
333	Water Wheels, Turbines, and Generators	2,093	47	2.13%	-
334	Accessory Electric Equipment	743	88	0.82%	-
335	Misc. Power Plant Equipment	137	20	-	5.00%
336	Roads, Railroads, and Bridges	120	-	-	-
337	Asset Retirement Costs for Hydraulic Production	0	-	-	-
Total Hydraulic Production Plant		**9,379**			
Other Production Plant*					
341	Structures and Improvements	24,480	38	2.64%	-
342	Fuel Holders, Products, and Accessories	12,541	39	2.64%	-
343	Prime Movers	71,192	39	2.64%	-
344	Generators	53,848	41	2.64%	-
345	Accessory Electric Equipment	7,742	44	2.64%	-
346	Misc. Power Plant Equipment	3,083	20	-	5.00%
347	Asset Retirement Costs for Other Production	-	-	-	-
Total Other Production Plant		**172,886**			
Total Production Plant		**327,478**			

* Other production plants include all plants other than steam, nuclear, and hydraulic production plants

Source: HELCO 2016 annual report; HECO Companies response to LEI data request

The average service life of structures is lower than for HECO, ranging from 38 to 65 years. Most of the equipment associated with electrical generation has an estimated service life ranging from 32 to 51 years depending on the category. The corresponding depreciation rates are shown in Figure 12.

4.2.2 Transmission & distribution assets

HELCO's transmission assets represent a total original cost of $180.3 million as of June 30, 2017, with the largest categories of assets, similar to HECO, being station equipment, poles and fixtures, and overhead conductors. The average service life for transmission assets ranges from 37 to 60 years. The corresponding depreciation rates are shown in Figure 13.

Figure 13. HELCO transmission assets by category

	TRANSMISSION PLANT	Original Cost ($ thousands)	Avg Service Life (years)	Depreciation Rate	Amortization Rate
352	Structures and Improvements	3,173	60	0.89%	-
353	Station Equipment	68,234	55	1.98%	-
354	Towers and Fixtures	61	50	2.12%	-
355	Poles and Fixtures	63,717	55	1.75%	-
356	Overhead Conductors and Devices	43,946	37	4.43%	-
357	Undergorund Conduit	312	60	-	-
358	Underground Conductors and Devices	686	50	0.18%	-
359	Roads and Trails	132	60	1.35%	-
Total Transmission Plant		**180,260**			

Source: HELCO 2016 annual report; HECO Companies response to LEI data request

The original cost for HELCO's distribution assets totals $671.4 million as of June 30, 2017, or just under four times the value of the transmission assets. Asset value is generally distributed over the overhead and underground categories. The average service life for all distribution assets ranges from 40 to 65 years, except for meters (30 years) and line transformers (28 years). The corresponding depreciation rates are shown in Figure 14.

Figure 14. HELCO distribution assets by category

	DISTRIBUTION PLANT	Original Cost ($ thousands)	Avg Service Life (years)	Depreciation Rate	Amortization Rate
361	Structures and Improvements	3,916	50	1.60%	-
362	Station Equipment	66,512	55	1.82%	-
363	Storage Battery Equipment	1,218	-	0.00%	-
364	Poles, Towers, and Fixtures	129,840	42	3.78%	-
365	Overhead Conductors and Devices	112,124	45	3.40%	-
366	Underground Conduit	36,063	47	2.87%	-
367	Underground Conductors and Devices	118,777	40	4.08%	-
368	Line Transformers	105,989	28	6.67%	-
369.1	Services - Overhead	75,648	45	3.47%	-
369.2	Services - Underground		53	2.85%	-
370	Meters	21,312	30	4.84%	-
Total Distribution Plant		**671,400**			

Source: HELCO 2016 annual report; HECO Companies response to LEI data request

4.2.3 Other assets

HELCO's other assets used to serve electric customers on Hawaii island are similar to HECO's (mostly office space and furniture, transportation equipment, communication equipment, and other miscellaneous items). The total original cost for these assets is $88.4 million as of June 30, 2017. The corresponding depreciation rates are shown in Figure 15.

Figure 15. HELCO general assets by category

	GENERAL PLANT	Original Cost ($ thousands)	Avg Service Life (years)	Depreciation Rate	Amortization Rate
390	Structures and Improvements	21,773	65	1.29%	
391.1	Office Furniture and Equipment - Information System Equipment	3,753	5	-	20.00%
391.2	Office Furniture and Equipment - Data Handling Equipment		10	-	10.00%
391.3	Office Furniture and Equipment		15		6.67%
392	Transportation Equipment	22,288	10	15.12% (under 13,000#) 2.72% (over 13,000#	
393	Stores Equipment	847	25	-	4.00%
394	Tools, Shop and Garage Equipment	11,169	25	-	4.00%
395	Laboratory Equipment	374	15	-	6.67%
396	Power Operated Equipment	1	18	-	5.58%
397	Communication Equipment	23,447	15	-	6.67%
398	Miscellaneous Equipment	4,739	15	-	6.67%
Total General Plant		**88,391**			

Source: HELCO 2016 annual report; HECO Companies response to LEI data request

4.3 MECO

As of June 30, 2017, MECO reported a total net book value (original cost minus accumulated depreciation) for its assets on the Maui, Molokai, and Lanai islands of $607.4, as illustrated in Figure 16.

Figure 16. MECO assets net book value

$ thousands	Production	T & D	General	Land	PHFFU	Total
Cost	411,826	654,385	59,218	1,713	1,303	1,128,445
Accumulated Depreciation	(257,568)	(238,428)	(25,059)	0	0	(521,055)
Net Book Value	**154,258**	**415,957**	**34,159**	**1,713**	**1,303**	**607,390**
Percent depreciated	**63%**	**36%**	**42%**	**0%**	**0%**	**46%**

Source: HECO Companies response to LEI data request

As for the other HECO Companies, MECO's largest share of assets in terms of value are in the Transmission and Distribution category, representing $416.0 million or 68.5% of the total net book value of the company's assets. Production assets are valued at $154.3 million, or 25.4% of the total value. Despite a slightly lower overall net book value than HELCO ($608 million versus $660 million for HELCO), the value for MECO's Transmission and Distribution assets are slightly higher than HELCO's ($416 million versus $405 million for HELCO).

Other assets, including the General, Land, and PHFFU categories, total $37.2 million or 6.1% of the total net asset value.

4.3.1 Production assets

The original cost of MECO's production assets represents $411.8 million as of June 30, 2017, with $122.2 million worth of property in the Steam Production Plant category and $289.6 million in the Other Production Plant category (this category includes MECO's combustion turbines and internal combustion engines on Maui, and internal combustion engines on Molokai and Lanai). The corresponding depreciation rates are shown in Figure 17.

Figure 17. MECO production assets by category

PRODUCTION PLANT		Original Cost ($ thousands)	Avg Service Life (years)	Depreciation Rate	Amortization Rate
Steam Production Plant					
311	Structures and Improvements	6,985	28	2.89%	-
312	Boiler Plant Equipment	52,156	27	3.75%	-
313	Engines and Engine-Drive Generators	-	-	0.00%	-
314	Turbogenerator Units	50,578	21	5.89%	-
315	Accessory Electric Equipment	9,165	27	4.19%	-
316	Misc. Power Plant Equipment	3,302	20	-	5.00%
317	Asset Retirement Costs for Steam Production	-	-	-	-
Total Steam Production Plant		**122,186**			
Other Production Plant*					
341	Structures and Improvements	42,847	29 to 45**	1.17% to 4.54%**	-
342	Fuel Holders, Products, and Accessories	8,564	28 to 45**	0.97% to 4.52%**	-
343	Prime Movers	50,738	31 to 52**	0.80% to 2.60%**	-
344	Generators	131,519	29 to 45**	1.54% to 3.54%**	-
345	Accessory Electric Equipment	38,497	29 to 46**	1.57% to 2.68%**	-
346	Misc. Power Plant Equipment	17,475	5	-	5.00%
347	Asset Retirement Costs for Other Production	-	-	-	-
Total Other Production Plant		**289,640**			
Total Production Plant		**411,826**			

* Other production plants include all plants other than steam, nuclear, and hydraulic production plants

** varies by island

Source: MECO 2016 annual report; HECO Companies response to LEI data request

The average service life of structures is lower than for HECO and HELCO, ranging from 28 to 45 years. Most of the equipment associated with electrical generation has an estimated service life ranging from 21 to 52 years depending on the category.

4.3.2 Transmission & distribution assets

MECO's transmission assets represent a total original cost of $126.9 million as of June 30, 2017, with the largest category of assets being station equipment. The average service life for transmission assets ranges from 50 to 70 years. The corresponding depreciation rates are shown in Figure 18.

Figure 18. MECO transmission assets by category

	TRANSMISSION PLANT	Original Cost ($ thousands)	Avg Service Life (years)	Depreciation Rate	Amortization Rate
352	Structures and Improvements	7,415	50	2.02%	-
353	Station Equipment	56,067	59	1.58% to 2.32%**	-
354	Towers and Fixtures	40	50	2.33%	-
355	Poles and Fixtures	33,766	70	0.77% to 1.57%**	-
356	Overhead Conductors and Devices	27,687	65	0.97% to 1.75%**	-
357	Undergorund Conduit	730	60	1.59%	-
358	Underground Conductors and Devices	1,221	50	1.98%	-
359	Roads and Trails	-	-	-	-
Total Transmission Plant		**126,925**			

** varies by island

Source: MECO 2016 annual report; HECO Companies response to LEI data request

MECO's distribution assets have a total original cost of totals $527.5 million as of June 30, 2017, or over four times the value of the transmission assets. Asset value is generally distributed over the overhead and underground categories. The average service life for all distribution assets ranges from 43 to 58 years, except for underground circuits with a service life of 80 years. The corresponding depreciation rates are shown in Figure 19.

Figure 19. MECO distribution assets by category

	DISTRIBUTION PLANT	Original Cost ($ thousands)	Avg Service Life (years)	Depreciation Rate	Amortization Rate
361	Structures and Improvements	1,788	50	2.02% to 2.03%**	-
362	Station Equipment	56,335	55	0.66% to 1.20%**	-
363	Storage Battery Equipment	5,559	-	-	-
364	Poles, Towers, and Fixtures	48,598	56	1.70% to 2.24%**	-
365	Overhead Conductors and Devices	68,317	58	1.65% to 1.77%**	-
366	Underground Conduit	64,995	80	2.03% to 2.27%**	-
367	Underground Conductors and Devices	84,606	55	1.17% to 1.74%**	-
368	Line Transformers	70,300	45	2.06% to 2.25%**	-
369.1	Services - Overhead	97,648	45	3.78% to 4.06%**	-
369.2	Services - Underground		45	2.32% to 2.61%**	-
370	Meters	14,873	43	1.21% to 1.95%**	-
373	Street Lighting and Signal Systems	14,440	45	1.52% to 1.87%**	-
Total Distribution Plant		**527,460**			

** varies by island

Source: MECO 2016 annual report; HECO Companies response to LEI data request

4.3.3 Other assets

Similar to HECO and HELCO, MECO's other assets for providing electrical service on Maui, Molokai, and Lanai islands mostly consist of office space and furniture, transportation equipment, communication equipment, and other miscellaneous items. The total original cost for these assets is $59.2 million as of June 30, 2017. The corresponding depreciation rates are shown in Figure 20.

Figure 20. MECO general assets by category

	GENERAL PLANT	Original Cost ($ thousands)	Avg Service Life (years)	Depreciation Rate	Amortization Rate
390	Structures and Improvements	13,461	65	0.85% to 1.38%**	
391.1	Office Furniture and Equipment - Information System Equipment	3,208	5	-	20.00%
391.2	Office Furniture and Equipment - Data Handling Equipment		10	-	10.00%
391.3	Office Furniture and Equipment		15		6.67%
392	Transportation Equipment	12,535	15 8	0.88% to 5.38% (over 13,000#) 3.05% to 8.75% (under 13,000#)	
393	Stores Equipment	573	25	-	4.00%
394	Tools, Shop and Garage Equipment	6,944	25	-	4.00%
395	Laboratory Equipment	446	15	-	6.67%
396	Power Operated Equipment	142	18	-	5.58%
397	Communication Equipment	20,577	15	-	6.67%
398	Miscellaneous Equipment	1,332	15	-	6.67%
Total General Plant		**59,218**			

** varies by island

Source: MECO 2016 annual report; HECO Companies response to LEI data request

4.4 KIUC

As of December 31, 2016, KIUC reported a total net book value (original cost minus accumulated depreciation) for its assets on Kauai Island of $244.7 million,[15] as illustrated in Figure 21.

Figure 21. KIUC assets net book value

$ thousands	Production	T & D	General	Land	Acquisitions	Other*	Total
Cost	143,178	260,953	36,220	10,180	54,852	10,497	515,881
Accumulated Depreciation	(76,107)	(138,513)	(20,513)	0	(31,082)	(4,970)	(271,185)
Net Book Value	**67,071**	**122,440**	**15,707**	**10,180**	**23,770**	**5,528**	**244,696**
Percent depreciated	**53%**	**53%**	**57%**	**0%**	**57%**	**47%**	**53%**

***Other costs include construction work in progress, while other accumulated depreciation include the Iniki deferred depreciation expense and retirement work in progress**

Source: KIUC 2016 Annual Report to the PUC

Similar with the other utilities in the State, KIUC's largest share of assets in terms of value is in the Transmission and Distribution category, representing $122.4 million or half of the total net book value of the company's assets. Production assets are valued at $67.0 million, or 27.4% of the

[15] This value includes the value of assets owned by KIUC and reported to the PUC in the annual report. KIUC investments in associated companies are excluded from this tally.

total value. KIUC also reported in 2016 an adjustment of $23.8 million for electric plant acquisitions.

Other assets, including the General, Land, and Other categories, total $31.4 million or 12.8% of the total net asset value.

4.4.1 Production assets

The original cost of KIUC's production assets represents $143.2 million, with $25.7 million worth of property in the Steam Production Plant category, $4.0 million for KIUC's hydroelectric plants, and $289.6 million in the Other Production Plant category (this category includes the combustion turbines, internal combustion engines, and renewable generation resources). The corresponding depreciation rates are shown in Figure 22.

Figure 22. KIUC production assets by category

PRODUCTION PLANT		Original Cost ($ thousands)	Avg Service Life (years)	Depreciation Rate
Steam Production Plant				
311	Structures and Improvements	5,639	51	2.59%
312	Boiler Plant Equipment	15,810	31	2.60%
313	Engines and Engine-Drive Generators	6	-	-
314	Turbogenerator Units	2,783	52	3.49%
315	Accessory Electric Equipment	777	54	2.52%
316	Misc. Power Plant Equipment	669	35	6.78%
317	Asset Retirement Costs for Steam Production	-	-	-
Total Steam Production Plant		**25,684**		
Hydraulic Production Plant				
331	Structures and Improvements	738	35	3.76%
332	Resevoirs, Dams, and Waterways	2,031	35	3.48%
333	Water Wheels, Turbines, and Generators	666	26	4.24%
334	Accessory Electric Equipment	582	-	-
335	Misc. Power Plant Equipment	-	-	-
336	Roads, Railroads, and Bridges	-	-	-
337	Asset Retirement Costs for Hydraulic Production	-	-	-
Total Hydraulic Production Plant		**4,017**		
Other Production Plant*				
341	Structures and Improvements	18,664	40	3.34%
342	Fuel Holders, Products, and Accessories	4,927	39	3.42%
343	Prime Movers	66,985	34	3.15%
344	Generators	11,312	37	2.98%
345	Accessory Electric Equipment	9,321	37	1.58%
346	Misc. Power Plant Equipment	2,268	34	2.44%
347	Asset Retirement Costs for Other Production	-	-	-
Total Other Production Plant		**113,476**		
Total Production Plant		**143,178**		

Sources: KIUC 2016 Annual Report to the PUC; "2012 Depreciation Study", Petition for Declaratory Ruling, Exhibit 2, Docket 2015-0127, May 8, 2015

The average service life of structures for production equipment on Kauai ranges from 35 to 51 years. Most of the equipment associated with electrical generation has an estimated service life ranging from 26 to 54 years depending on the category.

4.4.2 Transmission & distribution assets

Figure 23. KIUC transmission assets by category

	TRANSMISSION PLANT	Original Cost ($ thousands)	Avg Service Life (years)	Depreciation Rate
352	Structures and Improvements	263	51	1.33%
353	Station Equipment	25,607	38	2.50%
354	Towers and Fixtures	58	50	1.86%
355	Poles and Fixtures	30,534	56	1.22%
356	Overhead Conductors and Devices	20,793	42	2.01%
357	Undergorund Conduit	9	60	1.48%
358	Underground Conductors and Devices	492	50	2.18%
359	Roads and Trails	-	-	-
Total Transmission Plant		**77,755**		

Sources: KIUC 2016 Annual Report to the PUC; "2012 Depreciation Study", Petition for Declaratory Ruling, Exhibit 2, Docket 2015-0127, May 8, 2015

KIUC's transmission assets represent a total original cost of $77.8 million, with the largest categories of assets being associated with station equipment and overhead transmission. The average service life for transmission assets ranges from 38 to 60 years. The corresponding depreciation rates are shown in Figure 23.

Figure 24. KIUC distribution assets by category

	DISTRIBUTION PLANT	Original Cost ($ thousands)	Avg Service Life (years)	Depreciation Rate
361	Structures and Improvements	3,622	50	2.09%
362	Station Equipment	19,892	33	3.13%
363	Storage Battery Equipment	7,628	20	4.98%
364	Poles, Towers, and Fixtures	36,685	55	1.59%
365	Overhead Conductors and Devices	38,998	36	3.18%
366	Underground Conduit	7,944	63	1.34%
367	Underground Conductors and Devices	25,047	41	1.98%
368	Line Transformers	25,691	29	4.50%
369	Services	6,744	53	1.35%
370	Meters	7,417	15	13.59%
371	Installations on Customer's Premises	29	-	-
372	Leased Property	19	10	12.26%
373	Street Lighting and Signal Systems	3,482	25	2.45%
Total Distribution Plant		**183,197**		

Sources: KIUC 2016 Annual Report to the PUC; "2012 Depreciation Study", Petition for Declaratory Ruling, Exhibit 2, Docket 2015-0127, May 8, 2015

The total original cost of KIUC's distribution assets is $183.2 million as of December 31, 2016, or over twice the value of the transmission assets. Asset value is generally distributed over the

overhead and underground categories. The average service life for distribution assets is variable, from as low as 15 years for meters to more than 55 years for overhead distribution infrastructure and underground conduits. The corresponding depreciation rates are shown in Figure 24.

4.4.3 Other assets

Similar to the HECO Companies, KIUC's other assets for providing electrical service on Kauai island mostly consist of office space and furniture, transportation equipment, communication equipment, and other miscellaneous items. The total original cost for these assets is $36.2 million. The corresponding depreciation rates are shown in Figure 25.

Figure 25. KIUC general assets by category

GENERAL PLANT		Original Cost ($ thousands)	Avg Service Life (years)	Depreciation Rate
390	Structures and Improvements	11,619	42	1.91%
391	Office Furniture and Equipment	10,084	20	3.94%
392	Transportation Equipment	5,800	7	2.96%
393	Stores Equipment	172	21	3.81%
394	Tools, Shop and Garage Equipment	1,806	15	6.40%
395	Laboratory Equipment	823	15	4.75%
396	Power Operated Equipment	257	15	2.02%
397	Communication Equipment	4,319	16	5.23%
398	Miscellaneous Equipment	1,341	15	6.45%
Total General Plant		**36,220**		

Sources: KIUC 2016 Annual Report to the PUC; "2012 Depreciation Study", Petition for Declaratory Ruling, Exhibit 2, Docket 2015-0127, May 8, 2015

5 Appendix A: Scope of work to which this deliverable responds

Task 1.4.1 **Assessment of substantive estimate of book value for existing facilities that would need to be acquired to provide electrical services in each county.** CONTRACTOR shall provide a substantive estimate of the book value (original cost less depreciation) of the existing facilities that would need to be acquired to provide electrical service in each county.

DELIVERABLE FOR TASK 1.4.1. CONTRACTOR shall provide all work related to establishing a substantive estimate of book value for existing facilities that would need to be acquired to provide electrical service in each county, using existing financial data on equipment from utility filings, corporate filings, and indicative information about the asset. CONTRACTOR shall provide a list by county of assets and facilities that would need to be acquired, their book value, and sources for that estimated value provided in MS Excel with supporting documentation. CONTRACTOR shall submit deliverable for TASK 1.4.1 to the STATE for approval.

6 Appendix B: List of works consulted

FERC, "Uniform System of Accounts", web. https://www.ferc.gov/enforcement/acct-matts/usofa.asp

H.I. Wolk, J.L. Dodd, and M.G. Tearney. "Accounting Theory: Conceptual Issues in a Political and Economic Environment", 6th ed. South-Western., 2004, pp. 330-331

HECO, "HECO Direct Testimonies and Exhibits", HECO-202, Docket 2010-0053, March 30, 2010.

HECO, "Annual Report of Hawaiian Electric Company, Inc. to the Public Utilities Commission – State of Hawaii for the year ending December 31, 2016", filed May 24, 2017.

HELCO, "Annual Report of Hawaii Electric Light Company, Inc. to the Public Utilities Commission – State of Hawaii for the year ending December 31, 2016", filed May 24, 2017.

KIUC, "Annual Report of Kauai Island Utility Cooperative to the Public Utilities Commission – State of Hawaii for the year ending December 31, 2016", filed March 28, 2017.

KIUC, "Kauai Island Utility Cooperative 2016 Annual report", Web. http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/annualreport/AnnualReport2016.pdf

MECO, "Annual Report of Maui Electric Company, Limited to the Public Utilities Commission – State of Hawaii for the year ending December 31, 2016", filed May 24, 2017.

R.L. Hahne and G.E. Aliff, "Accounting for Public Utilities", LexisNexis, 1983, p. 101

SAIC, "2012 Depreciation Study – KIUC", August 2013. Filed on May 8, 2015 in Docket 2015-0127 as Exhibit 2 of KIUC's "Petition for Declaratory Ruling".

Economic Evaluation of Ownership and Operation for Each Ownership Model

prepared for Hawaii Department of Business, Economic Development & Tourism ("DBEDT") by London Economics International LLC

February 23, 2018





London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This document, Task 1.4.2, is one of several working papers issued as part of this engagement. It provides an overview of the major cost components such as capital costs, capital expenditures, purchased power and fuel expenses, and tax liabilities for the current utilities. In addition, it evaluates the impact of a change in ownership model on these costs with a discussion of the assumptions that drive the changes. The cost components and assumptions laid out in this deliverable will form the basis of a more comprehensive analysis of the impact of ownership models on utility finances and customer rates in Task 1.6.

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List of acronyms

CAPM	Capital Asset Pricing Model
CB	Competitive Bidding
CFC	Cooperative Finance Corporation
DBEDT	Hawaii Department of Business, Economic Development, and Tourism
DCF	Discounted Cash Flow
FFB	Federal Financing Bank
GSO	Grid System Operator
HECO	Hawaiian Electric Company
HEI	Hawaiian Electric Industries Inc.
HELCO	Hawaii Electric Light Company
IOU	Investor-Owned Utility
IPA	Illinois Power Agency
IPP	Independent Power Producer
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
LIBOR	London Interbank Offered Rate
MECO	Maui Electric Company
NCSC	National Cooperative Services Corporation
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
OPA	Ontario Power Authority
PPA	Power Purchase Agreement
PPP	Purchasing Power Parity

PSIP	Plan
PUA	Public Utility Act
PUC	Hawaii Public Utilities Commission
RAB	Regulatory Asset Base
REDG	Rural Economic Development Grant
RFP	Request for Proposals
RLF	Revolving Loan Fund
ROE	Return on Equity
RPS	Renewable Portfolio Standards
RUS	Rural Utilities Service
SB	Single Buyer
T&D	Transmission and Distribution
TIER	Times Interest Earned Ratio
TNB	Tenaga Nasional Berhad
USDA	United States Department of Agriculture
WACC	Weighted Average Cost of Capital

1 Executive Summary

London Economics International LLC, together with Meister Consultants Group (the "Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which corresponds to Task 1.4.2 in the project scope of work, provides an evaluation of the costs associated with four ownership models: Investor-Owned Utility ("IOU"), an electric cooperative ("co-op"), an independent Single Buyer ("SB") outside of the utility, and a ring-fenced SB within the IOU.

This paper also provides an overview of the assumptions and derivations of potential acquisition costs, operating and maintenance ("O&M") costs, likely annual capital investments, power supply costs, tax revenues, and regulatory compliance. These cost components and their underlying assumptions and derivations will be used to inform the Project Team's analyses of the impact on utility cash flows and customer rates. Those analyses and results will be discussed in detail in Tasks 1.6.3 – 1.6.5. Furthermore, these costs are discussed particularly in the context of the impact on utility expenses due to the transition from an existing utility ownership model to a new one – i.e., IOU to co-op, IOU to SB (outside), and IOU to SB (within the utility).

Figure 1. Illustration of impact on utility costs under different ownership models with respect to the current IOU model in Hawaii

	Coop	SB (within the utility)	SB (outside)
Upfront costs			
Setup	↑	↑	↑
Acquisition	↑	-	-
Personnel and transition	↑	↑	↑
Recurring			
Cost of capital	↓	-	-
Rate base	↓	↑	-
Power supply costs	-	↓	↓
Taxes	↓	-	-
Non-labor operating costs	-	↑	↑
Labor operating costs	-	↑	↑
Regulatory compliance	-	-	↑

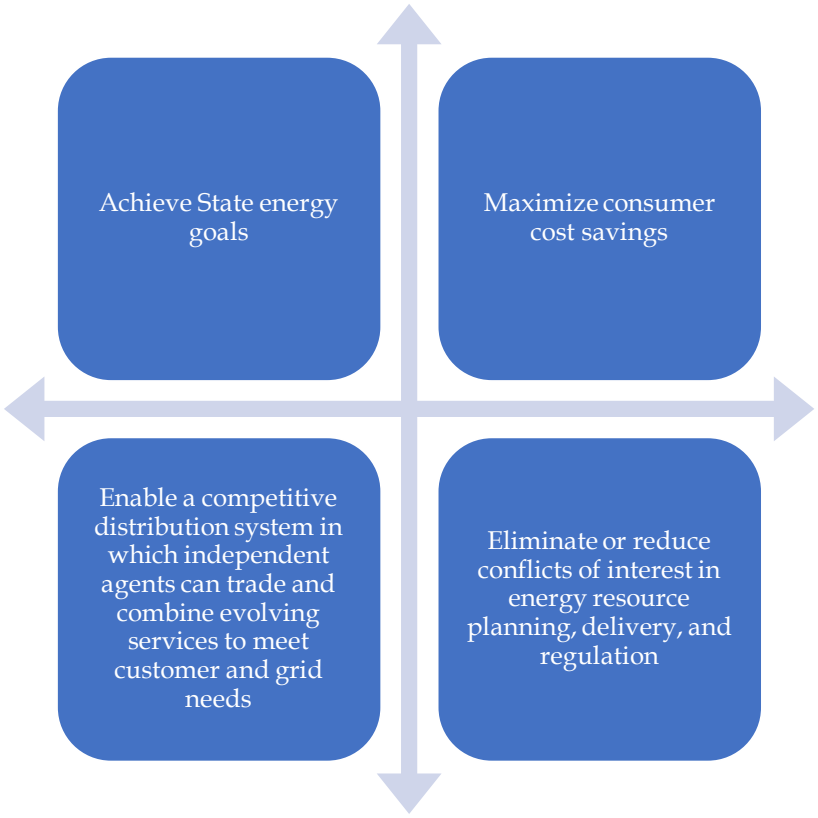
Source: LEI analysis.

Based on the Project Team's analysis, the upfront costs are higher for the transition from an IOU to a co-op, largely due to the acquisition costs as well as the extensive training required for the personnel. Once the operations begin under a co-op model, the utility's cost of capital and tax liabilities decrease. Under an SB model, there are additional costs of operating the SB alongside lower power supply costs. The economic costs and benefits of a new ownership model require evaluating whether costs decrease sufficiently under the new model to offset the initial costs. This analysis is not part of the scope of this task and will be addressed in Task 1.6.

2 Introduction and scope

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. LEI, through a competitive sealed proposals procurement,[1] was contracted to perform this study.[2]

Figure 2. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[3] listed in Figure 2. The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory

[1] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[2] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[3] House Bill No. 1700 Relating to the State Budget.

models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[4]

2.1 Role of this deliverable relative to others in the project

This deliverable corresponds to Task 1.4.2 in the project scope of work. It evaluates the major cost components of owning and operating utility assets and how they would vary under different ownership models. It includes descriptions of the sources and assumptions used to estimate the cost components, including forecasts out to 2045. The tables in this paper contain these preliminary estimates, including potential changes in costs under different ownership models. The assumptions for the major cost components evaluated in this deliverable will form the basis for analyses conducted in Task 1.6: Revenue and Financing.

It should be noted that the analysis of differences between ownership models is based on publicly available information.

2.2 Future refinements

As noted earlier, this deliverable is subject to further refinement and modification as the project moves forward and as we receive more information from the utilities on their future plans.

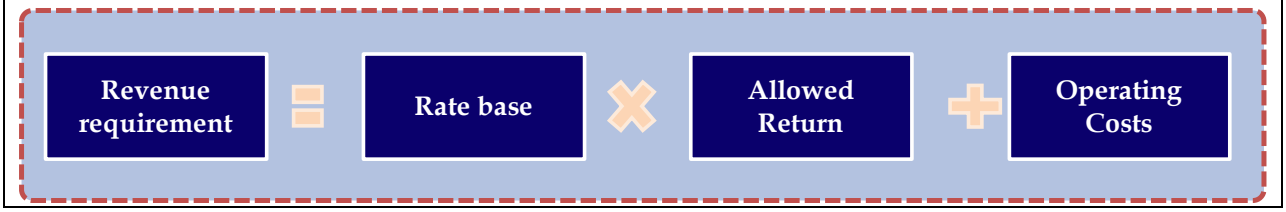
[4] Hawaii Contract No. 65595. Scope of Services.

3 Overview of the key concepts on the major cost components of owning and operating utility assets

An electric utility incurs various costs in providing service to its customers, such as investing in its assets, operating and maintaining them, and paying its employees. These costs are identified to determine the total revenues that must be recovered from ratepayers to ensure that the utility can cover its costs and earn a reasonable return on equity for its shareholders. Revenue requirement is the amount of revenue the utility needs to cover its cost of service. For the purpose of this paper, we will focus on the major costs related to the operations and maintenance of the day-to-day functions of the utility as well as capital investments. A detailed discussion of the revenue requirements will be done in Task 1.6.3.

The basic formula used to calculate revenue requirement is shown in Figure 3 below. It is important to note that this formula applies to IOUs. Electric cooperatives have a different approach to estimating revenue requirement, as described in more detail in Sections 4.1 and 5.1.2.1.

Figure 3. Basic revenue requirement formula (for IOUs)



The standard calculation of revenue requirement has three core components, namely the rate base, allowed return on rate base, and expenses:

- **Rate base** consists of the investments in plant, working capital, and value of investor contributions to the utility. More specifically, rate base consists of the undepreciated portion of cumulative investments in net utility plant and other items such as regulatory assets and working capital. Rate base is generally measured using book value of assets on a specific date, which may be the end of a calendar year or fiscal period.

- **Allowed rate of return** is generally set by the regulator as the financial return a utility is entitled to make on its rate base. Allowed rate of return is generally synonymous with the "cost of capital." It refers to the rate of return on rate base required to recover the utility's cost of debt, cost of preferred stock, and cost of common equity. This is discussed in detail in Section 3.2.

- **Operating costs include the operation and maintenance expenses, administrative and general expenses, and depreciation expense.** The O&M expenses represent the cost of operating and maintaining the utility plant and equipment or the cost of running the utility. The administrative and general expenses include salaries and wages, office supplies, regulatory commission expenses, and general plant maintenance. The depreciation expense is share of initial investment that has been allocated to that year.

This amount represents the recovery of the investment in facilities as opposed to profits from the investment.

3.1 Capital expenditure vs. operating expenditure

Capital expenditure ("capex") refers to all spending on acquiring a new asset or adding to the value of existing assets such that the benefits from the new or improved assets last longer than one accounting period, e.g., a tax year. For an electric utility, examples of capex include investments in generation, transmission, or distribution assets, vehicles, land, as well as office supplies like furniture and computers. Capex is documented as assets on the firm's balance sheet. In the revenue requirement formula, it increases the rate base. A capital asset is depreciated over its estimated useful life – i.e., the fixed costs of a capital asset are spread over its useful life. A depreciation expense is charged to the firm's income statement, and accumulated depreciation is logged on the firm's balance sheet as the total of all the depreciation expenses incurred to date on assets currently on the books; when an asset is retired, the accumulated depreciation associated with that asset is also reversed to remove it from the books.

On the other hand, operating expenditure ("opex") are expenses for the day-to-day operations of the firm. A utility's operating expenses include the salaries or wages of its employees, the costs of fuel used to run its plants, and the costs of procuring power or other services from third-party providers such as Independent Power Producers ("IPPs"). Unlike capex, opex are recorded on the firm's income statement as expenses in the same period that they are incurred. As Figure 3 indicates, opex is a "pass-through" component of a utility's revenue requirement – these costs are simply passed on to ratepayers.

3.2 Cost of capital

Cost of capital refers to the return that investors expect when they provide capital to the utility. The allowed return on a utility's rate base from Figure 3 is typically set at its cost of capital. This allows the utility to deliver expected returns to its investors and therefore attract sufficient capital for the investments necessary to continue to provide reliable service to its customers.

The weighted average cost of capital ("WACC") is the most commonly used approach to setting the rate of return for regulated utilities. In its simplest form, WACC comprises of the capital structure, cost of equity ("K_e"), and cost of debt ("K_d"), as shown in Figure 4. It reflects the costs of debt and equity through which a utility finances its investments, based on the proportion of each instrument in its capital structure. The sections below contain further detail on these items.

Figure 4. Vanilla WACC formula

$$WACC_{pre\text{-}tax} = K_d \times \frac{D}{(D+E)} + K_e \times \frac{E}{(D+E)}$$

where
D = level of debt
E = level of equity
} **Capital Structure**

Note: The formula above does not take into consideration the impact of tax shields

The inputs to the WACC calculation are usually derived using company- and country-specific market data. If such data is not available or reliable, it is also possible to use data from another market/region and adjust it for local specificities. WACC may be reported pre- or post-tax with implications on the level of debt of the firm. The net cost of debt is the interest paid minus the amount saved in taxes as a result of tax-deductible interest payments. The choice between pre-tax and post-tax rates is dependent on the cash flows being capitalized.

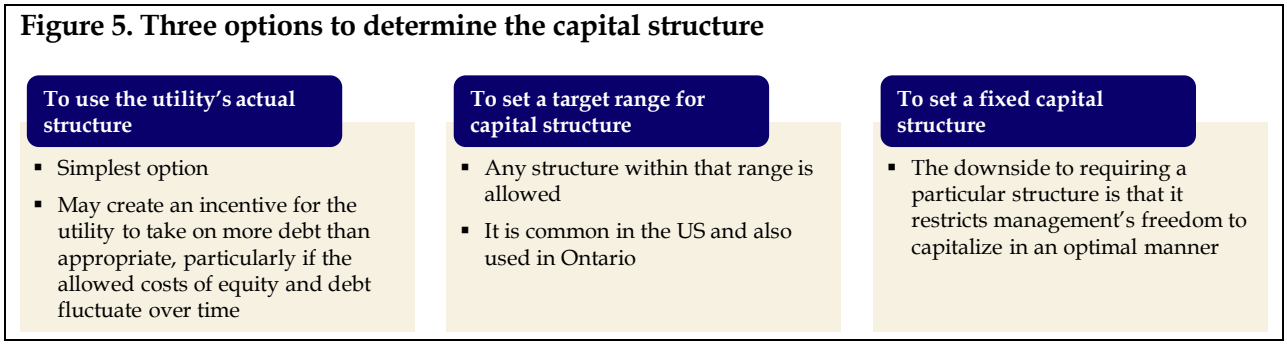
The WACC may also be quoted in either real or nominal dollar terms. The choice relates to whether the interest rate used in calculating the cost of debt should be shown as net of inflation or not. Generally, the inflation rate is estimated by the consumer price index and can be reported at the country or sector level.

3.2.1 Capital structure

The capital structure of a firm is the composition of the company's funding. There are generally two sources of funds – debt and equity. Debt is typically in the form of bond issues or long-term notes payable (such as taxable debt). Equity, on the other hand, includes common stock, preferred stock, or retained earnings.

There are three theoretical approaches that can be used to determine the capital structure of a regulated utility, as shown below in Figure 5: (i) using the utility's actual structure, (ii) setting a target range for the capital structure, and (iii) setting a fixed capital structure. In many jurisdictions, the capital structure was formerly tightly controlled to reduce the risk of utility bankruptcy. More recent regulatory systems set deemed capitalization structures, allowing utilities greater freedom in financing. If a utility chooses a capital structure differing from the deemed structure, it is only compensated on the deemed structure.

Figure 5. Three options to determine the capital structure



3.2.2 Cost of debt

The cost of debt reflects the interest rates paid on the long- and short-term debt instruments used by the utility. Regulators may face challenges in accurately estimating the cost of debt for a utility because of the multiple types of debt in the capital structure with different rates and characteristics. Historical interest rates on debt may also differ significantly from the prevailing market rate.

The cost of debt can be estimated using different approaches, which can broadly be categorized as: (i) market rate on debt, (ii) book rate on debt, and (iii) deemed debt rate. These approaches are

discussed further in Figure 6 and represent a conceptual framework rather than a strict methodology. In practice, the actual approach used may vary somewhat or combine multiple approaches due to the particular characteristics of the utility and its debt.

Figure 6. Approaches to Estimate the Cost of Debt

	Market rate on debt	Book rate on debt	Deemed debt rate
Where/when to use it	Only used for firms whose bonds are traded in a liquid market	Firms that have bank debt, or debt that is not frequently traded	In the event that the appropriate interest rate on debt is in question
How to use it	The current yield to maturity of the firm's debt should be used, preferably of long term bonds with good liquidity	For bank loans, the contracted rate of interest can be used; For floating rate debt, the current floating interest rate is most appropriate; For bonds, the most recently available yield to maturity can be used	The deemed debt rate should be set using the risk-free rate and a premium to account for the extra risk of the firm

The Hawaiian Electric Company ("HECO") calculated its projected cost of short-term debt based on an average of the rates obtained through a survey of two banks.[5] Likewise, it estimated its effective cost of long-term debt by dividing the total annual requirement for interest and the amortization of unamortized items by the net proceeds received from the sale of the securities.[6] The Project Team estimated Kauai Island Electric Cooperative's ("KIUC") effective cost of debt by dividing its total interest expense by its total long-term debt.

3.2.3 Cost of equity

The cost of equity, also known as the Return on Equity ("ROE"), reflects the proportion of return that is paid back to shareholders for the use of their capital. The Capital Asset Pricing Model ("CAPM") is one of the most widely used and simplest methods for estimating the expected return on equity. It measures the relationship between expected risk and return. The theory underlying CAPM states that investors are only compensated for systematic risk. Other commonly used techniques are the dividend growth model and the formula-based calculation. Figure 7 provides a description, examples of jurisdictions that use the method, advantages, and disadvantages of these three methods.

[5] HECO. *Docket No. 2016-0328: In the Matter of the Application of Hawaiian Electric Company, Inc. For Approval of General Rate Case and Revised Rate Schedules and Rules. Direct Testimonies and Exhibits – Book 10. HECO-2909.* December 2016.

[6] Ibid.

Robert Herbert, HECO's expert witness in its last rate case under Docket No. 2016-0328, used multiple analytical techniques to estimate ROE, including CAPM, the Bond Yield Plus Risk Premium approach, and the Discounted Cash Flow ("DCF") model.[7]

Figure 7. Methods to estimate the cost of equity

Options	Description	Examples	Advantages	Disadvantages
Capital Asset Pricing Model (CAPM)	A firm's cost of equity capital is equal to the risk-free rate of return on the market, plus a premium above the risk-free rate, to reflect the relative riskiness of the investment	Many US jurisdictions, Canada, the UK, Europe, Asia	Provides a theoretically justified cost of capital for equity	Backwards looking, with beta, the market risk premium, and the risk-free rate set using historical measures
Dividend growth model	• By using the current market price and a valuation model, such as the Dividend Discount model	Used by publicly traded companies. Usually not used by regulated entities.	Being entirely market-driven, the rate of return estimate is that demanded by the market	Highly volatile, completely dependent on the assumptions used by the estimator
Formula-based calculation	• Combines market data with a fixed factor to set the rate of return on equity • The rate of return for a utility would equal the risk-free rate, plus an estimate of the historical risk premium for utility stocks	Ontario, Canada for setting rates for electricity utilities	Allows the rate of return to vary with the rates of return in the market as a whole, but is still provides a high-degree of certainty	Fails to account for changes in the relative riskiness of the utility and the government bond used as a benchmark

Estimating KIUC's cost of equity capital is more challenging because its shareholders are its customer-members who make capital contributions but in a very different manner. Section 4.1 provides more detail, including the approach to estimating KIUC's ROE.

[7] HECO. *Docket No. 2016-0328: In the Matter of the Application of Hawaiian Electric Company, Inc. For Approval of General Rate Case and Revised Rate Schedules and Rules. Direct Testimonies and Exhibits – Book 9. HECO T-28.* December 2016.

4 Major cost components under the status quo

A utility's costs can be divided into two main categories – capital costs and O&M costs. The capital cost itself has two components – a utility's expenditure on purchasing or replacing its assets and its cost of financing this spending. Capital assets can include new physical plants or replace significant components of existing ones and have a useful life longer than a year. The utility's spending on these assets is financed by a combination of debt and equity, due to which it has interest expenses on its debt and provides regulated returns to its equity shareholders. There are also ongoing O&M expenses on its assets to provide service to the customers. These include the salaries paid to its employees, regular maintenance on its plants, fuel consumed by its plants, the costs of purchasing power generated by third-party generators, as well as its tax expenses. These costs are passed through to its ratepayers.

This section provides a discussion of the current figures for the major cost components and their explanation, including assumptions driving the Project Team's forecasts, where applicable, of these cost components through 2045. This discussion will also inform the Project Team's assumptions regarding the impact of a change in utility ownership model on these costs, as elaborated further in Section 5.

4.1 Cost of capital

HECO maintains a similar capital structure as its wholly-owned subsidiaries, Maui Electric Company ("MECO") and Hawaii Electric Light Company ("HELCO"). All three utilities (referred to as "the HECO Companies" in this document), source approximately 42% of their capital from long-term debt and approximately 57% from common stock, as shown in Figure 8. HECO is also the guarantor for its subsidiaries' special purpose revenue bonds, their respective notes issued, and trust preferred securities.[8] HECO would presumably withdraw this guarantee if MECO or HELCO changed ownership, which could impact their borrowing costs.

Since the capital structure of the HECO Companies is subject to regulatory approval, the Project Team assumes that it remains constant for the IOUs through 2045 under the status quo.

In 2014, HECO entered into a revolving non-collateralized credit agreement with a syndicate of nine financial institutions to create The Hawaiian Electric Facility, which increased its line of credit to $200 million.[9] Interest rates would be based on HECO's current long-term credit ratings, at the Adjusted London Interbank Offered Rate[10] ("LIBOR") (as defined in the agreement) plus

[8] HECO. *Annual Report of the Hawaiian Electric Company to the Public Utilities Commission, State of Hawaii, for the year ending December 31, 2016.* May 2017, page 109.1.

[9] HECO. *Annual Report to Hawaii PUC – 2016.* page 123.31.

[10] LIBOR, which stands for London Interbank Offered Rate, is the global benchmark for interest rate administered by Intercontinental Exchange. LIBOR is an average of the interest rates at which a group of leading banks are willing to lend to each other. There are 35 different rates – seven different maturities in five currencies. The three-month US dollar rate is most commonly used and typically referred to as the "current LIBOR rate."

137.5 basis points.[11] The Hawaiian Electric Facility can be used to support the issuance or repay short-term debt, make loans, or for capital expenditures, working capital, and general corporate purposes. While the HECO Companies can all draw from the facility, covenants of the facility restrict borrowing if it would cause the debt-to-capital ratio to exceed 65% for HECO, or 42% for MECO and HELCO.[12] In December 2016, HECO raised $40 million by issuing unsecured senior notes[13] due December 1, 2046.[14] The HECO Companies have $50 million and $96 million in long-term debt due in 2018 and 2020, respectively.[15]

Figure 8. HECO Companies – Capital structure as of December 31, 2016

	Common Stock	Preferred Stock	Long-Term Debt	Total
Amount ($000s)				
HECO	1,248,841	22,293	915,437	2,186,571
MECO	259,554	5,000	190,210	454,764
HELCO	291,291	7,000	213,703	511,994
HECO Companies Total	1,799,686	34,293	1,319,350	3,153,329
Weight				
HECO	57.1%	1.0%	41.9%	
MECO	57.1%	1.1%	41.8%	
HELCO	56.9%	1.4%	41.7%	
HECO Companies Total	57.1%	1.1%	41.8%	

Source: HECO Annual Report to Hawaii PUC – 2016.

Figure 9. HECO Companies – WACC

	Short-term Debt	Long-term Debt	Hybrids	Preferred Stock	Common Stock	WACC
Rate						
HECO	1.75%	5.19%	7.19%	5.37%	10.60%	8.28%
MECO	2.00%	4.59%	7.16%	8.15%	10.60%	8.05%
HELCO	1.50%	5.41%	7.21%	8.18%	10.60%	8.44%
HECO Companies Total	1.81%	5.15%	7.19%	6.36%	10.60%	8.28%

Source: HECO-3203, DOCKET NO. 2016-0328; MECO-2501, DOCKET NO. 2017-0150; and HELCO-2704, DOCKET NO. 2015-0170.

[11] HECO. *Annual Report to Hawaii PUC – 2016.* page 123.31.

[12] Ibid.

[13] Unsecured senior notes are a type of debt obligation which receives priority payments over other credit obligations (seniority) in case of the issuer's bankruptcy, but one which is not backed by the issuer's assets as collateral.

[14] HECO. *Annual Report to Hawaii PUC – 2016.* page 123.31.

[15] Ibid.

The most recently available WACC for the HECO Companies are shown in Figure 9. The Project Team assumes that WACC for the HECO Companies remains constant at these levels (HECO – 8.28%, MECO – 8.05%, and HELCO – 8.44%) through 2045 under the status quo.

On the other hand, as a rural electric cooperative, KIUC has different sources and costs of capital compared to IOUs like the HECO Companies.[16] The bulk of KIUC's equity comes from members through rates and charges. In addition to the equity contribution of its founding members, all electricity users can choose to become a member of KIUC and make capital contributions through rates. While each member has one vote, KIUC also has an outside investor with a non-controlling equity interest in one of its wholly-owned subsidiaries.[17]

Figure 10. KIUC – Capital Structure

	Long-term Debt	Controlling Equity	Non-Controlling Equity	Total
Amount ($000s)	208,650	102,981	21,518	**333,149**
Weight	62.6%	30.9%	6.5%	

Source: KIUC 2016 Annual Report.

As mentioned previously, the revenue requirement for an IOU is intended to allow the utility to cover its opex and provide a reasonable return on equity to its investors on its rate base. In the case of KIUC, its revenue requirement is calculated to enable it to achieve a target Times Interest Earned Ratio ("TIER"), set by the US Department of Agriculture's ("USDA") Rural Utilities Service ("RUS") as an average minimum TIER level of at least 1.25 for the highest two out of three calendar years; KIUC's regulated TIER level is 2.50.[18] The textbox below describes TIER and how co-ops grow their equity using patronage capital from their members.

The amount of patronage capital that KIUC returns to its members is generally limited to 25% margins in the prior calendar year.[19] This has enabled KIUC to grow its equity while lowering its indebtedness. Figure 11 shows the evolution of its capital structure over the last five years in its utility business, excluding the subsidiaries established to develop power projects with outside investors.

[16] Task 1.6.5. will discuss in detail the different financing options under each ownership model.

[17] KIUC. *2016 Annual Report.* Page 11.

[18] KIUC. *Docket No. 2009-0050. Application of Kauai Island Utility Cooperative for Approval of Rate Changes and Increases, Revised Rate Schedules and Rules, and Other Ratemaking Matters. Volume 1.* June 2009. Page 10.

[19] KIUC. *Consolidated Financial Statements – December 31, 2016 and 2015.* April 2017. Page 10.

Co-op Financing

Patronage Capital

A co-op uses the revenue collected through rates to pay for operating expenses and debt service (interest and principal). The remainder is its margin for the year, also referred to as patronage capital. Each member has a patronage capital account, representing his/her ownership of the co-op. Every year, the margins are allocated to the members as credits to their patronage capital account. The distribution is based on the members' electricity usage in that year. Depending on the state of the co-op's finances, it may return a certain proportion of patronage capital to members every year as checks or bill credits. The patronage capital that is returned to the members is considered retired. Generally, co-ops retire patronage capital by older vintages first.

The remaining patronage capital remains credited to the members account but is invested by the co-op in the grid. This is the equity capital provided by a co-op's owners – its members. Thus, co-ops can grow their equity (patronage capital) if new patronage capital is greater than the amount retired.

Times Interest Earned Ratio ("TIER")

TIER is a solvency ratio that measures a co-op's ability to meet its long-term debt obligations. It is calculated by dividing the sum of net income and total interest expense by total interest expense. Net income is essentially operating margin in the case of a co-op.

$$TIER = (Interest\ Expense + Margins)/(Interest\ Expense)$$

The ratio measures how many times a co-op can cover its interest expenses from its pre-tax earnings. Although RUS loan agreements require a minimum TIER of 1.25 for distribution utilities, the PUC sets the regulated TIER level for KIUC at 2.50. The revenue requirement for an electric co-op is set so that it earns sufficient margins to achieve the target TIER level. The margins enable the co-op to maintain financial stability and fund capital expenditure without incurring more debt.

Source: USDA. "What are Patronage Refunds?" Agricultural Cooperative Service, Cooperative Information Report Number 9. January 1985.

Figure 11. KIUC - Patronage Capital Growth (utility only)

$000s	2012	2013	2014	2015	2016
Patronage Capital & Memberships	78,546	85,289	93,019	96,529	102,981
Total Long-Term Debt	177,646	177,469	175,434	172,126	193,362
Total Capital	256,192	262,758	268,453	268,654	296,343

Source: KIUC 2016 Annual Report to the PUC.

As a rural utility, KIUC has access to low-cost debt from federal agencies like RUS and Federal Financing Bank ("FFB"), as well as from private sector sources like Cooperative Finance

Corporation ("CFC") and National Cooperative Services Corporation ("NCSC"). KIUC also maintains several lines-of-credit with CFC, secured by its assets: $60 million for disasters, $5 million for short-term financing, and $20 million over five years for construction financing with CFC.[20] In addition, the co-op also has a 1-year unsecured $25 million line-of-credit for working capital with CoBank.[21]

Figure 12. KIUC Long-term Debt (as of December 31, 2016)

Following is a summary of long-term debt at December 31:

	2016	2015
Fixed and variable notes payable due to RUS in monthly installments of principal and interest with rates ranging from 0.875% to 4.875%, maturing October 31, 2027	$ -	$ 135,150,216
Fixed and variable notes payable due to FFB in quarterly installments of principal and interest with rates ranging from 1.341% to 4.430%, maturing December 31, 2023	15,572,923	17,527,651
Fixed and variable notes payable due to FFB in quarterly installments of principal and interest with rates ranging from 1.574% to 3.334%, maturing December 31, 2042	76,130,690	42,323,272
Fixed note payable due to CFC in quarterly installments of principal and interest at a rate of 2.725%, maturing September 30, 2023	3,330,420	3,771,737
Fixed note payable due to CFC in monthly installments of principal and interest at a rate of 2.55%, maturing March 31, 2028	126,472,472	-
RUS/FFB advance payments (cushion of credit)	(13,748,381)	(13,081,919)
Fixed noted payable due to NCSC in quarterly installments of principal and interest at a rate of 4.650%, maturing June 30, 2039	15,693,917	16,081,407
Total long-term debt	223,452,041	201,772,364
Less current maturities	(14,802,318)	(13,952,739)
Long-term debt, less current maturities	$ 208,649,723	$ 187,819,625

Source: KIUC Consolidated Financial Statements. Page 17.

KIUC receives Rural Economic Development Grants ("REDG") from the USDA Rural Development Office, which in turn provides loans to eligible borrowers at 0% interest for up to ten years. When the loan is repaid, the funds go into the Revolving Loan Fund ("RLF") to fund new loans to additional projects. Only the initial loan made by the intermediary (in this case

[20] Ibid. Page 18.

[21] Ibid.

KIUC) is required to be at zero interest.[22] KIUC can only use the REDG funds to provide loans for activities that promote rural economic development and job creation projects.

KIUC does not have an explicit breakdown of its WACC like the HECO Companies in Figure 9, but the approved rate increase in its last rate case from 2009 (approved in 2010) resulted in a 5.43% return on net rate base for the 2010 test year, lower than KIUC's requested rate increase for a 10.04% return.[23, 24] KIUC's revenue requirements are based on TIER levels rather than WACC because equity contributions from its members in the form of patronage capital are different from investments made by shareholders with an expectation of return.

4.2 Annual capital investments

In the Hawaiian Electric Companies' Power Supply Improvement Plan Update report from December 2016 ("PSIP"), the HECO Companies have laid out their capital investment plans looking out to 2045. These plans account for investments to modernize transmission and distribution ("T&D") infrastructure to withstand greater penetration of distributed and renewable resources, as discussed in their Modernizing Hawaii's Grid for Our Customers ("Grid Modernization") document. The utilities earn a regulated rate of return on these investments approved by the Hawaii Public Utilities Commission ("PUC"). The capital expenditure categories for the forecasted expenditures enumerated in Figure 14 are described below. The Project Team will use these numbers in calculating the revenue requirements:

1. **Power supply expenditure** includes investments in new generation resources, as well as major reliability investments in existing units;

2. **Smart Grid and ERP** are specific capital projects, and these categories capture specific expenditures for those projects; and

3. **Balance-of-utility capital expenditures** are expenses for grid modernization such as T&D upgrades, energy storage, and synchronous condensers.[25]

[22] USDA Rural Development. *Rural Economic Development Loan and Grant Programs, RD Instruction 4280-A.*

[23] Hawaii PUC. *Docket No. 2009-0050. Decision and Order.* September 2010. Page 15-19.

[24] KIUC. *Docket No. 2009-0050. Application – Volume 1. Exhibit 9.*

[25] HECO. *PSIP Update Report – Book 1.* Page 5-2.

Figure 13. HECO Companies – Projected Capital Expenditures ($000s, nominal)

HECO	2017-2021	2022-2025	2026-2030	2031-2035	2036-2040	2041-2045	Total
Power Supply	294,800	209,937	24,779	20,064	15,749	7,182	572,511
Smart Grid	90,910	11,855	9,062	7,021	5,543	0	124,391
ERP	47,747	0	0	0	0	0	47,747
Balance-of-utility business	1,290,835	958,637	1,725,726	1,357,979	1,374,708	1,955,370	8,663,255
Total	**1,724,292**	**1,180,429**	**1,759,567**	**1,385,064**	**1,396,000**	**1,962,552**	**9,407,904**

MECO	2017-2021	2022-2025	2026-2030	2031-2035	2036-2040	2041-2045	Total
Power Supply	0	0	0	0	0	0	0
Smart Grid	17,559	1,626	1,639	1,634	1,153	0	23,611
ERP	8,667	0	0	0	0	0	8,667
Balance-of-utility business	306,115	259,466	226,840	254,720	287,822	251,347	1,586,310
Total	**332,341**	**261,092**	**228,479**	**256,354**	**288,975**	**251,347**	**1,618,588**

HELCO	2017-2021	2022-2025	2026-2030	2031-2035	2036-2040	2041-2045	Total
Power Supply	92,425	0	0	0	0	0	92,425
Smart Grid	21,948	2,139	2,201	2,054	1,429	0	29,771
ERP	9,173	0	0	0	0	0	9,173
Balance-of-utility business	345,908	227,694	332,901	350,397	370,337	393,456	2,020,693
Total	**469,454**	**229,833**	**335,102**	**352,451**	**371,766**	**393,456**	**2,152,062**

Source: PSIP Update Report, Book 1. Page 5-5 to 5-27.

On the other hand, KIUC's capex plan only looks forward five years (2017-2021) but in more granular detail. Its major capital projects include upgrades to generation and T&D infrastructure, as well as energy management software replacement. Figure 15 presents this capex plan.

Beyond 2021, the Project Team will use the 5-year average for capex between 2017 and 2021 and adjust for inflation. Renewable penetration is already higher in KIUC compared to the HECO Companies, so it is likely that they will also have slower growth in capital spending.

Figure 14. KIUC - 2017 5-year Construction Plan ($000s, nominal)

$000s	2017	2018	2019	2020	2021	5 Years
Normal and Recurring						
Production	980	930	905	905	905	4,625
T&D	6,844	6,401	7,108	7,077	6,207	33,637
Member Service	108	111	114	118	118	568
HCP	779	749	749	749	749	3,775
Safety & Facilities	175	150	150	150	150	775
Information Services	3,208	532	550	535	535	5,360
General Plant	799	658	687	625	613	3,380
Total Recurring	**12,893**	**9,530**	**10,263**	**10,158**	**9,276**	**52,120**
Non-Recurring						
Production	450	10,800	1,500	440	175	13,365
T&D	7,605	4,700	12,685	14,300	0	39,290
Engineering	1,600	2,200	0	0	0	3,800
Total Recurring	**9,655**	**17,700**	**14,185**	**14,740**	**175**	**56,455**
Carryover Projects	**2,822**	**1,000**	**5,950**	**0**	**0**	**9,772**
Total CapEx	**25,370**	**28,230**	**30,398**	**24,898**	**9,451**	**118,348**

Source: KIUC – 2017 Capital Improvements Program for Ensuing Five Years for 2017 to 2021; LEI analysis for the next 5 years.

4.3 Power supply – fuel and purchased power costs

Electric utilities incur fixed and variable costs in producing or procuring the electricity sold to customers. The capex described in Section 4.2 constitutes the fixed cost component. Of the costs that vary with the amount of electricity sold, the two biggest categories are fuel costs and purchased power costs. Unlike capex, these expenses do not earn a return for the IOUs (or their shareholders). They are passed through to ratepayers.

The HECO Companies and KIUC supply their customers with a combination of electricity generated by their own power plants and electricity purchased from Independent Power Producers ("IPPs"). Fuel costs refer to the costs of purchasing fuels like diesel or fuel oil used to generate electricity in the utility-owned thermal power plants. Likewise, the utilities also buy the power generated from plants owned by IPPs, at terms typically specified in Power Purchase Agreements ("PPAs") between the transacting parties.

The HECO Companies' current fuel and purchased power costs are available from their rate case filings. This information for KIUC is also available from their annual reports submitted to the Hawaii PUC, including for the most recent five years. The assumptions used to project these costs, as discussed below, will also be used to generate estimates for 2016 (or the most recent period) as a comparison with actual 2016 data from the utilities.

Figure 15. Power Supply Expenses – 2016

Expenses ($000s)	HECO	MECO	HELCO	KIUC
Fuel oil	305,359	94,251	55,094	34,559
Purchased power	431,009	50,713	81,018	28,205

Source: HECO – Annual Report to Hawaii PUC 2016; KIUC 2016 Annual Report to the PUC.

The Project Team has previously compiled a database of the State's generation assets by county for Task 1.1.3, relying on the most recently available information on each generator's capacity, fuel used, capacity factor, and heat rate. The HECO Companies' PSIP document also contains detailed plans for new resources including resource type and capacity, looking out to 2045. The Project Team assumes that the planned capacity additions will be owned by IPPs, except for the soon-to-be-completed Schofield Barracks Generating Station and HECO's solar project at Joint Base Pearl Harbor Hickam West Loch Annex that is under construction.[26]

Unlike HECO, KIUC has affirmed its intentions to develop new utility-scale renewable plants. In an interview with ThinkTech Hawaii, the CEO of KIUC, David Bissell, suggests that their focus in Kauai, for now, is more on utility-scale solar and storage rather than on growing distributed solar on rooftops because utility-scale is 2- to 2.5-times cheaper and more readily deployable.[27] KIUC has also created two wholly-owned subsidiaries, KIUC Renewable Solutions One LLC ("KRS One") and KIUC Renewable Solutions Two LLC ("KRS Two"), that would each construct, own, and operate a solar PV facility and sell the power generated to KIUC.[28] The ownership of KRS Two has since been transferred to a KIUC-owned holding company subsidiary and split with an investor.[29]

Using the information on the characteristics and timeline of generation resources, together with the forecasts of fuel prices provided by HECO in the PSIP and assumptions about efficiency loss and O&M cost increases, the Project Team will estimate the electricity generation and corresponding fuel costs for thermal plants. This will apply to fuel costs for utility-owned generation, and also inform the purchased power costs for thermal plants owned by IPPs. With regards to KIUC, the Project Team will use a similar approach, including HECO's fuel price forecasts and assumptions about the retirement of existing units, to inform projections for KIUC's fuel expenses.

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[26] HECO. *Hawaiian Electric, U.S. Navy break ground on West Lock solar project.* Press Release. April 16, 2018. Web. <https://www.hawaiianelectric.com/Documents/about_us/news/2018/20180416_west_loch_PV_groundbreaking.pdf>

[27] Bissell, David. *On Kauai, the Future is Now with KIUC.* ThinkTech Hawaii, February 16, 2017. Interview. Accessed October 19, 2017.

[28] KIUC. *Consolidated Financial Statements – December 31, 2016 and 2015.* April 2017. Page 8.

[29] Ibid.

Similarly, future costs of purchasing power from IPPs on current contracts will be informed by details of utilities' PPAs from rate case filings and annual financial reports to the PUC. The Project Team will estimate the cost of future PPAs based on HECO's planned new resources and using assumptions for capital and O&M costs of new generation. The HECO Companies provide the replacement resource capital cost assumptions in the PSIP. Future O&M cost assumptions will be obtained from National Renewable Energy Laboratory's ("NREL") Annual Technology Baseline and Lazard's Levelized Cost of Storage analysis for battery storage. The PSIP report also projects the energy mix by resource type for each of HECO, MECO, and HELCO. This data will help to align the Project Team's generation estimates with HECO Companies' planned transition of its resource mix.

For KIUC, the Project Team will use load forecasts and assumptions about current unit retirement to infer the generation and capacity additions necessary. The Project Team will assume that new generation is split equally between KIUC's project development subsidiaries and IPPs since KIUC remains committed to developing its own utility-scale renewable projects. The costs of the new PPAs with IPPs will be estimated using the same approach as for HECO.

As the utilities gradually replace the power generated from their thermal plants with power procured from IPPs or new renewable capacity, their fuel costs will decrease over time and purchased power expenses will increase, regardless of the ownership model. However, the level of increase in purchased power expenses can vary, as will be discussed later in Section 5.2.2.3. These estimates will be included in the revenue requirements model for Task 1.6.3.

4.4 Taxes

4.4.1 Taxes other than income

Taxes other than income consists of public service tax, PUC fees, franchise tax, and payroll tax. Payroll taxes are calculated on the labor portion of O&M expenses. The Project Team will estimate the effective payroll tax rate based on actual 2016 data in determining the revenue requirements. This rate will be applied to projections of O&M labor expense based on assumptions that index its various components to inflation, sales, population growth, etc.

The other taxes are charged as a percentage of operating revenues and are therefore referred to as revenue taxes. The rates for revenue taxes, as shown in Figure 17, are the same in all the counties and apply to a utility regardless of ownership model.

Figure 16. Revenue Tax Rates

Public Service Tax	PUC Fees	Franchise Tax
5.885%	0.500%	2.500%

Source: HECO-3203, DOCKET NO. 2016-0328.

4.4.2 Federal and state income tax expense

As a rural electric cooperative, KIUC is exempt from federal income taxes. Therefore, it is not affected by the recent decision to lower federal income tax rates for corporations from 35% to

21%. The co-op does pay state income taxes, however, which is 6.015% in Hawaii. The new federal tax rates will lower the HECO Companies' effective income tax rate from 38.91% to 25.75%.[30]

Figure 17. Estimated impact of Tax Cuts and Jobs Act on income taxes (based on major 2016 revenues and expenses)

Tax expenses with 35% vs. 21% federal tax rate

($000s)	HECO	MECO	HELCO	KIUC
Operating Revenue	1,472,002	308,588	310,863	143,499
O&M Expense	(1,008,805)	(213,353)	(199,951)	(98,880)
Taxes other than Income Taxes	(141,465)	(29,227)	(28,984)	(12,060)
EBITDA	321,732	66,008	81,928	32,559
Depreciation Expense	(130,259)	(24,790)	(40,589)	(18,473)
EBIT (Operating Income)	191,473	41,218	41,339	14,087
Interest Expense	(43,844)	(9,184)	(11,340)	(7,658)
Income before tax	147,629	32,034	29,999	6,429
Federal Income Tax Rate	35%	35%	35%	0%
State Income Tax Rate	6.015%	6.015%	6.015%	6.015%
Effective Income Tax Rate	38.910%	38.910%	38.910%	6.015%
Total Income Tax Expense	57,442	12,464	11,673	387
Federal Income Tax Rate	21%	21%	21%	0%
State Income Tax Rate	6.015%	6.015%	6.015%	6.015%
Effective Income Tax Rate	25.752%	25.752%	25.752%	6.015%
Total Income Tax Expense	38,017	8,249	7,725	387
Impact of lower corporate taxes	**19,425**	**4,215**	**3,947**	**0**

Source: SNL; HECO-3203, DOCKET NO. 2016-0328; KIUC 2016 Annual Report.

For the HECO Companies, and potentially their ratepayers, the benefits are significant. While the actual tax expenses may vary due to previous tax deferrals, a 21% corporate tax rate would have lowered their tax liabilities for 2016 by over $19 million for HECO and about $4 million each for MECO and HELCO.

For the revenue requirement projections, the Project Team will assume a 21% federal income tax rate from 2018 onwards for the HECO Companies ,and that state tax rate remains at 6.015% through 2045.

[30] Effective tax rate comprises of federal tax rate + state tax rate – (federal tax rate * state tax rate). This reflects the deductibility of state income tax expenses for federal income tax; i.e. state income tax expense can be subtracted from taxable income for the purpose of federal income tax.

5 Cost impact of ownership model change

With a change in utility ownership model, there are one-time costs associated with the transition. For a transition from an IOU to a co-op, the one-time costs include the costs of setting up a co-op, securing financing to purchase the IOU's assets, and reorienting the organization and its personnel under a new mission. Once the transition takes place, it alters some of the expenses of the utility. The terms of financing the purchase will adjust the capital costs, and as a co-op, the utility will no longer have federal income tax expenditure.

Creating a Single Buyer ("SB"), whether as an independent body or a ring-fenced entity within the existing IOU, also requires initial expenditure in establishing the regulatory and legal frameworks for its operation, and setting up the physical office facilities, staff, accounting and information technology ("IT") infrastructure, as well as the software necessary to carry out its functions. Once established, there will be additional expenses of operating the SB, alongside an expected reduction in purchased power costs for the utility.

5.1 IOU to Co-op

This section addresses a possible scenario where an electric cooperative carries out a buyout of the current IOU's assets. Since the analysis is conducted at a county level, the three counties in which the HECO Companies operate are evaluated individually. Any synergies or additional costs arising from a buyout of the IOU in more than one county are not taken into account. The analysis also assumes that a buyout would encompass the entirety of the existing IOU's assets and operations in a county. For instance, a co-op that acquires MECO from the parent company would be the successor utility in all of Maui, Lanai, and Molokai islands. A scenario in which the ownership of MECO's assets and operations in only Lanai or Molokai changes hands is beyond the scope of this study.

5.1.1 Non-recurring costs

The non-recurring costs refer to the initial expenditure incurred up to the point where the utility operations commence under co-op ownership in the three counties currently with IOUs. These costs include all the steps necessary to form the co-op, secure legislative and regulatory approval, purchase the utility assets from the incumbent IOU, and transition current utility staff to a new organization. They are discussed in more detail in the subsequent sections. The model accounts for all the transition costs associated with establishing a co-op and its acquisition of the existing IOU. The detailed methodology to estimate those costs is discussed in the Task 1.3.1 report.

5.1.1.1 Setup, legal, and regulatory costs

Several steps are necessary to establish an electric co-op before it can secure the financing and approvals necessary for acquisition. These range from initial studies and stakeholder outreach to establishing the co-op's by-laws and leadership.

The structure and operations of KIUC offer an example for electric co-ops in other Hawaii counties to model themselves on. As an organization providing a public utility service to the customers that also own it, it is important to engage extensively with the local communities to secure their support for the co-op. Therefore, it is still necessary for them to go through the full

cycle of stakeholder outreach to determine the governing principles and organizational structure of the co-op to ensure their success. There must be initial meetings amongst the major stakeholders, leading to the formation of a core leadership body. This group would not only drive the co-op formation process through stakeholder engagement and establishing the co-op's by-laws, but it would likely also be the primary source for initial capital for the necessary studies, fees, and applications.

As explained in Task 1.3.1, the costs for creating a co-op are estimated to range between $2.3 million and $3.3 million.

Figure 18. Co-op – estimated setup costs

Coop Formation Steps	Cost ($000s)
Initial Leadership and Stakeholder Discussion	< 10
Formation of a Provisional Committee	< 10
Survey the Local Population	1 - 40
Formation of a Steering Committee	< 100
Legal Outreach	> 250
Feasibility Studies and Financial Analysis	> 10
Incorporation and By-Laws	< 10
Membership Recruitment	< 100
Founding Assembly Meeting and Election of the Boa	< 10
Regulatory Approval	2,000 - 2,500
Total Coop Formation Costs	**2,350 - 3,320**

Source: Task 1.3.1.

5.1.1.2 Acquisition costs

To take over the utility operations, the newly formed co-op will have to buy the incumbent IOU's assets. The purchase price, including the assumption of its debt obligations, is driven by a mutually acceptable valuation of its assets and the transaction costs. In addition, the purchase price and terms must be approved by the PUC. It is assumed that the co-op will secure low-cost debt from USDA's Rural Utilities Service, Cooperative Finance Corporation, and National Cooperative Services Corporation to finance the purchase. Upon acquisition, the capital structure of the new co-op will be almost entirely based on debt. It will be able to grow its equity with capital contributions from new members and reinvesting part of its operating margins.

There are several approaches to valuations, which are discussed in more detail in Task 1.3.1. Based on those analyses, the acquisition costs for HECO, MECO, and HELCO are shown in Figure 20 and Figure 21. In addition to the purchase price, there would also be transaction costs of about 1.16% of the transaction value.[31]

[31] Task 1.3.1.

Figure 19. Results of Comparable Trading Analysis

	Average Enterprise Value	Average Equity Valuation	Average Cost per Share
HECO	$3,082 MM	$1,768 MM	$16.24
HELCO	$697 MM	$415 MM	$3.81
MECO	$651 MM	$380 MM	$3.49
HECO Companies	$4,430 MM	$2,562 MM	$23.54

Figure 20. Results of Comparative Transactions Analysis

	Average Enterprise Value	Average Equity Valuation	Average Cost per Share
HECO	$3,249 MM	$1,935 MM	$17.77
HELCO	$761 MM	$479 MM	$4.40
MECO	$675 MM	$404 MM	$3.71
HECO Companies	$4,685 MM	$2,817 MM	$25.88

Source: Task 1.3.1

5.1.1.3 Personnel and organizational transition costs

After the acquisition is completed, the ideal scenario for the new co-op would be to retain most of the existing staff. They bring valuable skillsets and a deep knowledge of the utility's assets and operating conditions. As with any major reorganization, it is likely that there will be some turnover of employees. This could be due to shifting in workforce culture, an emphasis on local hiring, or change in compensation schemes. It is expected that the board and senior leadership will undergo training programs in managing an electric co-op, similar to what happened when KIUC was acquired. These costs are estimated to be greater than $250,000.[32]

5.1.2 Recurring costs

Once a co-op commences operations, some of its cost components will differ from those of the current IOU. These recurring differences in costs will impact the utility's revenue requirement on a yearly basis.

The model makes assumptions about some changes in the cost components after the co-op commences operations. The model only includes changes that have a tangible and quantifiable basis and does not include potential costs reduction from greater community engagement or customer-centric approach. For instance, LEI does not assume any differences in planned capex once the IOU transitions to a co-op. Unlike IOUs, which earn a return on their asset base, co-ops do not have the incentive to inflate their capex. However, the HECO Companies' aging grid and generation assets will require significant investments to modernize it, regardless of the ownership model.

5.1.2.1 Cost of capital

As discussed in more detail in Section 4.1, a combination of debt and equity investors finance the utility's capital expenditure. The different sources of debt financing available to co-ops as well as

[32] Task 1.3.1.

the leveraged buyout of the IOU impact the interest expenses. Similarly, the regulated rate of return to an IOU's shareholders no longer directly apply to co-ops due to their membership-based equity structure.

The analysis assumes that the purchase will be entirely debt-financed, just like KIUC's purchase of Kauai Electric. Existing long-term debt of the incumbent IOU will also be refinanced at the terms available to co-ops. Revenue requirements for utilities are calculated to recover their operating and capital costs. The capital costs for an IOU include the allowed returns to its shareholders. In contrast, the equivalent allocation for a co-op is meant to cover its interest expenses with sufficient margin and generate cash (equity capital) for capital expenses instead of debt funding. Figure 22 and Figure 23 below show the formula of the revenue requirements under an IOU and co-op models. Task 1.6.3 will provide a more detailed discussion of the revenue requirements under the different ownership models.

Figure 21. IOU Revenue Requirements

$$Revenue\ Requirement = Regulatory\ Asset\ Base\ ("RAB") * WACC + Operating\ Expenses$$

Figure 22. Co-op Revenue Requirements

$$TIER = (Interest\ Expense + Margins)/(Interest\ Expense)$$

$$Margins = Interest\ Expense * (TIER - 1)$$

$$Revenue\ Requirement = Interest\ Expense * (TIER - 1) + Operating\ Expenses$$

KIUC's last rate case filing from 2009 recommends a regulatory TIER level of 2.50 and affirms that its goal is to reach an equity level of 30% as contained in its Equity Management Plan.[33] Therefore, the model will assume that the co-ops that take over from incumbent IOUs will start at ~100% debt financing, and eventually stabilize around a 70:30 debt-to-equity ratio.

Figure 23. KIUC Interest Expenses

$000s	2012	2013	2014	2015	2016	Average
Total Long-Term Debt	177,646	177,469	175,434	172,126	193,362	
Interest Expense - Long-Term Debt	8,335	7,738	7,362	6,770	6,916	
Approx. Blended Interest Rate		4.36%	4.15%	3.86%	4.02%	4.10%

Source: KIUC 2016 Annual Report to the PUC.

Figure 25 evaluates a hypothetical case with the HECO Companies as co-ops in 2016. Interest expenses are calculated based on acquisition costs from Figure 21. The 100% debt scenario estimates interest expenses in the first year after the debt-financed acquisition, and the 70% debt scenario estimates interest expenses for a mature co-op that has achieved the 30% equity target. This enables comparison between the annual capital costs of an IOU with co-op margins at a TIER

[33] KIUC. *Docket No. 2009-0050. Application – Volume 2. Exhibit KIUC 10-T-400.* Page 5-6.

level of 2.50. Co-op margins can be calculated using the second formula in Figure 23, multiplying interest expense by TIER minus 1 (or by 1.5 at TIER level 2.5). The analysis in Figure 26 uses the net book value of plants as a substitute for the RAB since actual rate bases for MECO and HELCO are not available for 2016.

Figure 24. Indicative Interest Expenses for a Co-op after Acquiring the HECO Companies (based on enterprise valuation using comparative transactions analysis)

($000s)	100 % Debt	Interest Expense	70 % Debt	Interest Expense
HECO	3,249,000	133,060	2,274,300	93,142
MECO	761,000	31,166	532,700	21,816
HELCO	675,000	27,644	472,500	19,351
HECO Companies Total	4,685,000	191,870	3,279,500	134,309

Source: LEI analysis.

RAB reflects the net investment in an IOU's assets from investors, adjusted for depreciation. Net plant, or the physical utility assets including land and vehicles, is the largest asset category in RAB for the HECO Companies. RAB also comprises of other accounting assets like inventory and deferred costs, as well as regulatory assets created when the regulator allows a utility to move some of its expenses from its income statement to its balance sheet and earn a return.

Figure 25. Indicative Capital Cost Impact of Change in Ownership

IOU

($000s)	Net Plant	WACC	Capital Costs
HECO	2,557,890	8.28%	211,760
MECO	631,367	8.05%	50,856
HELCO	662,224	8.44%	55,918
HECO Companies Total	3,851,481		318,534

Coop - 100% Debt * TIER - 1 = 2.50 - 1 = 1.50

($000s)	Interest Expense	TIER - 1*	Margins	Decrease vs IOU	
HECO	133,060	1.50	199,590	12,170	5.7%
MECO	31,166	1.50	46,749	4,107	8.1%
HELCO	27,644	1.50	41,466	14,452	25.8%
HECO Companies Total	191,870		287,805	30,729	9.6%

Coop - 70% Debt * TIER - 1 = 2.50 - 1 = 1.50

($000s)	Interest Expense	TIER - 1*	Margins	Decrease vs IOU	
HECO	93,142	1.50	139,713	72,047	34.0%
MECO	21,816	1.50	32,724	18,132	35.7%
HELCO	19,351	1.50	29,026	26,891	48.1%
HECO Companies Total	134,309		201,464	117,071	36.8%

Source: Net Plant from Exhibit 1a – Plant Information @ Q4-2016, HEI Data Request.

5.1.2.2 Taxes

As discussed earlier, the other component of revenue requirements from Figure 22 and Figure 23 is operating expenses. These are assumed to be the same for both IOU and co-op, except for

federal income tax expense. With corporate taxes lowered from 35% to 21% at the federal level, the potential savings from avoided federal income tax expenses will be almost halved.

Figure 26. Estimated Savings from Federal Tax Exemption – based on 2016 tax liabilities

($000s)	IOU	Co-op	Savings
35% Federal Tax Rate			
HECO	57,442	8,880	48,562
MECO	12,464	1,927	10,538
HELCO	11,673	1,804	9,868
HECO Companies Total	**81,579**	**12,611**	**68,968**
21% Federal Tax Rate			
HECO	38,017	8,880	29,137
MECO	8,249	1,927	6,323
HELCO	7,725	1,804	5,921
HECO Companies Total	**53,992**	**12,611**	**41,381**

Source: SNL; HECO-3203, DOCKET NO. 2016-0328.

5.1.2.3 Regulatory costs

KIUC has typically faced a lighter regulatory oversight from PUC than the HECO Companies. In 31 out of the 47 states that have electric cooperatives, regulators allow co-ops to effectively self-regulate through their elected boards.[34] KIUC has considered seeking eventual exemption from regulation by the PUC.[35] While one would expect lighter PUC regulation to result in lower administrative costs for regulatory matters, KIUC's administrative expenses for regulatory matters from the last five years have been higher than the HECO Companies. This analysis will assume that the higher expenses are due to shared resources amongst the HECO Companies and will maintain regulatory costs at current levels even after the transition to a co-op.

Figure 27. Administration & General Expenses - Regulatory Commission

($000s)	2012	2013	2014	2015	2016	5-year average
HECO	398	476	509	580	290	451
MECO	1,149	364	247	249	0	402
HELCO	783	253	0	0	0	207
HECO Total	2,330	1,093	756	829	290	1,060
KIUC	1,149	1,657	1,368	1,239	1,312	1,345

Source: SNL; KIUC Annual Report to the PUC (2012-2016).

[34] University of Wisconsin Center for Cooperatives. "Research on the Economic Impact of Cooperatives." June 2009.

[35] KIUC. *2016 Annual Report.* Page 7.

If a co-op is exempt from PUC regulation, it saves an addition 0.5% in revenue taxes for PUC fees (see Figure 17). Since KIUC has not officially requested approval for exemption from PUC regulation, this analysis will assume that the PUC will retain current levels of oversight over the HECO Companies' successor utilities even after they transition to a co-op.

5.1.2.4 Co-op Board Training

Even after a co-op has been established, the board of directors typically participate in training programs every year to ensure that they remain up-to-date on the best practices of co-op governance. The project team assumes that the annual expense on board training will be based on the average expense for the past five years (2012 – 2016), as shown below.

Figure 28. KIUC Board of Directors – Training Expenses

($000s)	2012	2013	2014	2015	2016	5-year average
Training and travel expense	77.9	84.7	93.5	65.9	69.9	78.4

Source: KIUC. Board Travel Expenses.

5.1.3 Net Impact – IOU to Co-op

Summarizing the analyses in the sections above gives us the following results, based on preliminary analyses: if the incumbent IOUs had started operations as co-ops in 2016, their opex for that year would have been lower by approximately $60 million for HECO, $14 million for MECO, and $24 million for HELCO.

Figure 29. IOU to Co-op – Illustrative Impact on 2016 Operating Expenses

($000s)	HECO	MECO	HELCO
Cost of capital	(12,170)	(4,107)	(14,452)
Taxes	(48,563)	(10,538)	(9,868)
Board Training	78	78	78
Net Impact	(60,655)	(14,566)	(24,241)

Source: LEI analysis.

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5.2 IOU to Single Buyer (Outside)

IOUs have an inherent incentive to increase their capex to grow the rate base on which they earn a rate of return. On the generation side of the business, vertically-integrated utilities such as the HECO Companies would prefer to own and operate their own plants rather than purchase the energy produced by IPPs, ceteris paribus. Regulators like the PUC are tasked with providing oversight to ensure fair competition among the suppliers, but when an entity that owns generation is also in charge of system planning and power procurement, claims of bias from IPPs may be hard to avoid and harder to prove or disprove. Creating a separate entity as an independent SB removes those incentives for HECO Companies by taking planning and procurement responsibilities away from the utility.

Illinois Power Agency

The Illinois Power Agency ("IPA") was created in 2007 by the Public Act 95-0481 (SB 1592). The IPA Act together with modifications to the Public Utility Act ("PUA") replaced the Illinois Auction with a portfolio procurement process. IPA's goals and responsibilities include:

- Develop electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability, for residential and small commercial customers of Ameren, ComEd, and MidAmerican.
- Conduct competitive procurement processes.
- Develop and implement a Zero Emission Standard Procurement Plan.
- Develop a Long-Term Renewable Resources Procurement Plan and implement the programs and procurements contained in the Plan.
- Develop electric generation and co-generation facilities that use indigenous coal and/or renewable resources financed with bonds issued by Illinois Finance Authority.
- Supply electricity from any Agency facilities at cost to municipal electric systems, governmental aggregators, or rural electric cooperatives in Illinois.

As an independent agency, the IPA is subject to the oversight of the Executive Ethics Commission. It actively administers four individual nonshared governmental funds – the IPA Operations Fund, the IPA Trust Fund, the IPA Investment Fund, and the IPA Renewable Energy Resources Fund – for its operations, costs incurred in connection with the operation and maintenance of an IPA facility, retirement of revenue bonds issued for an IPA facility, and purchasing renewable energy credits, etc.

Source: Illinois Power Agency. Annual Report Fiscal Year 2016; Illinois Power Agency Act.

An independent SB is a completely separate organization with no ties to the utility. This model is compatible with varying levels of unbundling and competition in utility operations, but the Project Team assumes that a separate SB will function alongside the incumbent IOU in its current level of vertical integration.

The Project Team envisions the SB as a profit neutral entity, generating just enough revenues through fees collected from the system operator (the IOUs in this case) to recover its expenses. There are initial costs of creating and setting up an SB, and then ongoing expenses for its operations. The following sections evaluate the additional costs of creating and operating an independent SB against resulting reductions in the power supply and utility expenses. Detailed analyses will be conducted in Tasks 1.6.3 – 1.6.5.

5.2.1 Non-recurring costs

As with a co-op, SB requires legislative and regulatory directions when it is established. They are necessary to clearly delineate its authority from that of the IOU and to define its functions, processes, and the mechanisms through which it would achieve its revenue requirement. Once an SB is created, there are also significant initial expenditures associated with establishing its office such as purchasing the furnishings, computers, and IT infrastructure, recruiting staff and training them on the SB's operations and software.

5.2.1.1 Setup legislation and regulatory guidelines

An SB model represents a smaller change in the utility business model than transitioning from an IOU to a co-op. There are none of the complexities associated with acquisition transactions because the utility will continue to own all its assets. There is also some precedence in the state of Hawaii in promulgating similar frameworks. The Competitive Bidding Framework ("CB Framework") adopted by the PUC, which outlines a mechanism for utilities to acquire generation resources through a competitive bidding process, is essentially a limited implementation of the SB model. The PUC has also previously recognized the conflict between utility incentives and energy efficiency programs and authorized Hawaii Energy, a third-party administrator, to manage and deliver energy-efficiency and demand-side management programs and services under the oversight of the PUC.[36]

The process to establish an SB will likely entail stakeholder outreach to hold discussions on an SB model, its value, and collect suggestions on its guiding framework. Other costs will include fees for legal counsel in drafting the legislation and SB guidelines and securing regulatory approval. Task 1.3.1 describes the steps required to establish an SB model and acknowledges the uncertainty regarding some of the costs. For projections of revenue requirements, the Project Team assumes that these costs will be similar to those incurred in setting up a co-op (as shown in Figure 19), amounting to $2.3 - $3.3 million.

5.2.1.2 Office facilities, personnel, and IT infrastructure

The SB will have its own physical office space and accompanying facilities and infrastructure for its functions of system planning and procurement. Currently, these functions are carried out by the IOU, so establishing the SB essentially moves them from the IOU to a new external organization. The IOU would be the first option to recruit personnel and obtain the necessary infrastructure, but it will likely opt to retain some capabilities for system planning for its own purposes. It cannot be ascertained how much of the IOU's resources involved in the planning and

[36] Hawaii Energy (Leidos, Inc.). *Annual Report – Program Year 2016*. Page 7.

procurement functions also serve other responsibilities. Therefore, there will likely be a degree of duplicating these functions at the IOU and the SB.

Ontario Power Authority

The Ontario Power Authority ("OPA") was established under the *Electricity Restructuring Act, 2004* and started operations in January 2005. It was a non-profit organization governed by an independent board of directors, licensed and regulated by the Ontario Energy Board, and reported to the Ontario Legislative Assembly through the Minister of Energy. It was merged with the Independent Electricity System Operator in January 2015. Prio to its merger, the OPA was responsible for maintaining long-term electricity supply. The OPA integrated power system planning, generation development, conservation, and electricity sector development under one umbrella.

As envisioned for an independent SB model for the HECO Companies, the OPA was responsible for preparing integrated system plans for generation, transmission, and conservation as well as procuring those resources through bilateral contracts or competition.

Source: Illinois Power Agency. Annual Report Fiscal Year 2016; Illinois Power Agency Act.

Figure 30. Ontario Power Authority – SB Capex

	Cost (2005 CAD)	Asset Life (years)	Cost ($000s, 2016 USD)
Furniture and equipment	1,174,275	10	1,431
Leasehold improvements	1,458,998	Length of lease	1,779
Computer hardware and software	693,839	2.5	846
Audio visual equipment	135,843	10	166
Telephone system	49,217	5	60
Total	3,512,172		4,281

Note: FX conversion to 2005 USD (1 USD = 1.02 CAD); adjusted for inflation at 2%.

Source: Ontario Power Authority. 2005 Annual Report.

Figure 31. Forecasted SB Capex for the first year of operations - HECO Companies

($000s)	HECO	MECO	HELCO
Initial Capex	3,140	514	913

Source: LEI analysis.

Estimates for these costs shown in Figure 32 are derived using the capex costs obtained from the Ontario Power Authority ("OPA") from 2005, the year in which it was established. The initial capex for an SB for each of the HECO Companies is based on OPA's first-year capex, adjusted for

inflation and scaled down by the respective number of employees. OPA employed 75 staff in 2005, and the respective numbers for the HECO Companies are discussed in Section 5.2.2.1.[37]

5.2.2 Recurring costs

Once an SB commences operations, it incurs ongoing expenses on its personnel and office facilities. The SB will also face annual audits to maintain compliance with the PUC. However, the increased competition in power procurement will help to lower the power supply costs. The utility's current expenditures on staff and software involved in their planning and procurement processes also decrease.

5.2.2.1 Operating expenses

System planning and power procurement will be conducted through software or online interfaces, which will require ongoing licensing fees and upgrade costs. The financial statement for Illinois Power Agency ("IPA") shows that almost 99% of its expenditures fall under the "employment and economic development" category.[38] Once established, the SB's expenses from its day-to-day operations will be primarily from labor and non-labor O&M expenses such as salaries, rent, training, software licenses, and other office expenses.

The three utilities of the HECO Companies' each have their own planning and procurement capabilities. As the largest of the three, HECO has three distinct planning departments: Advanced Planning, Technical Planning Services, and T&D Planning. MECO and HELCO each have one smaller department called Customer Solutions and Planning Department and System Operations and Planning Department, respectively. The size and annual opex of these departments are shown below in Figure 33. Comparable information was not available for KIUC.

Figure 32. HECO Companies' System Planning – Current Staffing and Expenditure

2016 data (actual or budgeted)	HECO	MECO	HELCO
# of staff	55	9	16
Labor expense ($000s)	3,549	846	1,623
Non-Labor expense ($000s)	6,189	4,083	3,976
Total annual expense ($000s)	9,738	4,929	5,599

Source: HECO-1101 & HECO-1109A, DOCKET NO. 2016-0328; MECO-702 & MECO-705, DOCKET NO. 2017-0150; and HELCO-602 & HELCO-605, DOCKET NO. 2015-0170.

The Project Team will assume that an SB corresponding to each incumbent IOU will be similarly staffed and incur similar expenses as the current planning department in that IOU. Some of the functions of the IOUs' current planning department, such as load dispatch, will not be relevant

[37] Ontario Power Authority. *Ensuring Ontario's Electricity Future. Annual Report 2005.* March 2006. Web. February 16, 2018.

[38] Illinois Power Agency. *Audited Financial Statement and Notes - Fiscal Year 2016.* January 2017.

to an SB. However, it will be responsible for conducting competitive auctions for power supply. It will also require its own staff and IT infrastructure for human resources, accounting, regulatory affairs, and other administrative functions since it will not be able to share these resources with the utility anymore. For simplification, the Project Team will assume that the loss of some functions and gain of others will result in a net zero impact on the SB's size and expenses.

The SB is also required to maintain a separate physical office. For rental costs, the analysis assumes an office space of ~250 square feet per employee. Based on average asking base rent in Oahu for the commercial real estate is $1.69/sq. feet per month,[39] annual rental expenses for the three potential SBs are shown below in Figure 34. The Project Team will use the same rate for Maui and Hawaii Island because comparable rates were not available for those counties.

Figure 33. SB Office Estimated Rent Expense by IOU

	HECO	MECO	HELCO
# of staff	55	9	16
Space per employee (sq ft)	250	250	250
Rent base ($/sq ft per month)	1.69	1.69	1.69
Annual Rental Expense ($000s)	279	46	81

Source: LEI analysis.

The net increase in costs from the transition to an SB model will not be the full cost of SB operations; transferring some of the capabilities and personnel to an SB will lower the IOU's own costs. As mentioned before, the IOUs will retain the responsibilities and associated staff and infrastructure for functions not relevant to an SB. They may also maintain some capability to replicate the SB's functions for their own strategic planning and system operations. For example, the IOU will no longer have to procure power supply directly from IPPs, but it will still need the personnel and online portals to manage procurement of other supplies and services. To be conservative, the Project Team will assume this overlap to be 50%, decreasing the IOU's O&M expenditure on system planning by half of what it would have been under the status quo. It is unlikely that the HECO Companies' office space requirements will be significantly different due to an SB, so the office expenditures will not change.

5.2.2.2 Audit and regulatory oversight

As a separate public entity, the SB will face annual audits and make other submissions as required by the PUC. This is necessary to maintain accountability, especially since its costs are ultimately passed on to ratepayers.

[39] DBEDT. Research and Economic Analysis. *2016 The State of Hawaii Data Book: A Statistical Abstract.* November 2017.

According to the National Council of Nonprofits, an independent audit for a non-profit can cost from $10,000 to $20,000.[40] Therefore, the Project Team estimates the cost of a public audit of the SB by an accounting firm at $15,000 per audit. For reference, KIUC's Communications Manager Beth Tokioka estimates that the co-op's annual financial audit costs approximately $65,000.[41]

5.2.2.3 Purchased power costs

The SB will determine system needs and obtain the necessary generation supply based on long-run least cost and ensuring the reliability of the system. The procurement will be competitive, with IPPs and the IOU all able to submit bids if they can meet the resource specifications laid out by the SB. In the current vertically-integrated model, the IOU has little incentive to push for lower PPA prices from its IPP counterparts because purchased power costs are passed through to ratepayers. Legislators and regulators can also build in incentive mechanisms for the SB based on its ability to deliver lower costs.

Hawaii does have a competitive procurement framework in place (see text box below) that the HECO Companies must abide by to source generation resources. However, the IOUs do still have an incentive to set resource characteristics requirements in a Request for Proposals ("RFP") such that it would favor their generation assets over those of IPPs. During the wave of restructuring in the power sector in the 1990s, FERC and several states determined that the utility-based SB model did not do enough to correct utility incentives to abuse their role as system operator.[42] An independent SB with oversight of both planning and procurement would help level the playing field between IPPs and the utility. A well-designed SB framework ensures that, regardless of ownership, only resources that can meet the required performance criteria at the lowest cost get contracted.

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[40] National Council of NonProfits. *Nonprofit Audit Guide*. Web. <https://www.councilofnonprofits.org/nonprofit-audit-guide/what-is-independent-audit>

[41] Tokioka, Beth. "FW: Questions on KIUC's transition to coop." Message to Cherrylin Trinidad. February 7, 2018. Email.

[42] FERC. *Promoting Wholesale Competition Through Open-Access Non-discriminatory Transmission Services by Public Utilities, Docket No. RM95-8-000, Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Docket No. RM94-7-001*. September 1996.

Competitive procurement framework in Hawaii

In December 2006, the Competitive Bidding Framework ("CB Framework") was adopted by the Hawaii PUC as part of its Order No. 23121. It aims to "*govern competitive bidding as a mechanism for acquiring or building new energy generation in Hawaii*." It outlines a comprehensive mechanism for the HECO Companies as well as KIUC to acquire generation resources through a competitive bidding process. Utilities must specify the proposed scope of the RFP for any generation resources deemed subject to competitive bidding in that the Integrated Resource Plan. They are required to provide adequate notice of its request for proposals ("RFPs"), and to enable the comparison of a wide range of supply-side options. The Hawaii PUC primarily ensures that each competitive bidding process is fair in its design and implementation, and the utilities' interests are aligned with the public interest even where the utility has dual roles as designer and participant. The proposed RFPs, contracts that result from the competitive bidding process, and tariffs for interconnection and transmission upgrades required, etc. are all subject to the PUC's review and approval. In addition, whenever a utility seeks to advance a project proposal, an Independent Observer is required to monitor the competitive bidding process and report to the PUC. Alternatively, the HECO Companies may apply for a waiver of the competitive bidding requirements for certain projects that are not compatible with the competitive bidding process.

In the PUC's Order No. 23298, KIUC was granted exemption from the CB Framework in February 2007, as in its cooperative ownership structure, there is no substantial difference in economic interests between its member owners and its customers. Moreover, KIUC contends that there are already sufficient protections of competitive procurement in place, so the oversight of CB Framework is redundant. As required by the Rural Utilities Service, KIUC shall utilize competitive procurement in obtaining its goods and services. Additionally, KIUC has access to low-cost funding through its lenders that can assist in keeping bids as low as possible. Its Board of Directors also have a fiduciary responsibility to its members to encourage cost and technological efficiencies. Of course, this exemption from the CB Framework is subject to the PUC's right to reexamine it, consistent with the public interest or any change involving KIUC's ownership structure. Although KIUC has more flexibility on procuring new renewable energy projects, it does still require the PUC's approval for large renewable energy projects.

Sources:

Hawaii PUC. Instituting a Proceeding to Investigate Competitive Bidding for New Generating Capacity in Hawaii. Decision and Order No. 23121. Docket No. 03-0372.

Hawaii PUC. Instituting a Proceeding to Investigate Competitive Bidding for New Generating Capacity in Hawaii. Decision and Order No. 23298. Docket No. 03-0372.

HSEO. Utility Resources. Website. <http://energy.hawaii.gov/developer-investor/utility-resources>. Access Date: February 14, 2018.

The text box below shows several quantitative studies on the benefits of competition, which show efficiency gains to be between 3% and 14%. As there is already a competitive framework in place, the Project Team will conservatively assume 3% lower costs for purchased power with respect to current forecasts from the HECO Companies. In 2016, 3% efficiency gains from competitive

procurement would have lowered the HECO Companies' costs to purchase electricity from IPPs by $16.9 million ($12.9 million for HECO, $1.5 million for MECO, and $2.4 million for HELCO).

Studies on Benefits of Competition and Unbundling

Author(s)	Title	Study Period	Efficiency Gain
K. Fabrizio, N. Rose, & C. Wolfram (2007)	Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on US Electric Generation Efficiency.	1981-1999	3%
P. O'Connor (2017)	Restructuring Recharged: The Superior Performance of Competitive Electricity Markets 2008-2016.	2008-2016	8%
H. Zhang (2007)	Does Electricity Restructuring Work? Evidence from the U.S. Nuclear Industry.	1992-1998	11%
J. Craig & S. Savage (2013)	Market Restructuring, Competition and the Efficiency of Electricity Generation: Point-level Evidence from the United States 1996 to 2006.	1996-2006	9%
A. Kleit & D. Tecrell (2001)	Measuring Potential Efficiency Gains from Deregulation of Electricity Generation: A Bayesian Approach	1996	13%
H. Chan, H. Fell, I. Lange, & S. Li (2012)	Efficiency and Environmental Impacts of Electricity Restructuring on Coal-fired Power Plants.	1991-2005	13%
L. Davis & C. Wolfram (2012)	Deregulation, Consolidation, and Efficiency: Evidence from US Nuclear Power.	1970-2009	10%
J. Bushnell & C. Wolfram (2005)	Ownership Change, Incentives and Plant Efficiency: The Divestiture of US Electric Generation Plants.	1998-2001	2%
K. Akkemik & F. Oguz (2010)	Regulation, efficiency and equilibrium: A general equilibrium analysis of liberalization in the Turkish electricity.		14%
M. Azad, M. Covich, & S. Sojoodi (2015)	The Impact of Electricity Competitive Market Establishment on Technical Efficiency of Thermal Power Plants in Iran.	1999-2011	2.60%
H. Gao and J. Van Biesebroeck (2014)	Effects of deregulation and vertical unbundling on the performance of China's electricity generation sector.	1999-2007	7%
P. Domah and M. Pollitt (2000)	The Restructuring and Privatization of the Electricity Distribution and Supply Businesses in England and Wales: A Social Cost Benefit Analysis.	1990-1998	2X

Figure 34. 2016 Purchased Power Costs and Potential Savings

($000s)	Actual 2016	Savings (w/ 3% reduction)
HECO	431,009	12,930
MECO	50,713	1,521
HELCO	81,018	2,431
HECO Total	562,740	16,882

Source: HECO – Annual Report to Hawaii PUC 2016.

5.2.3 Net Impact – IOU to Single Buyer (Outside the Utility)

Summarizing the analyses in the sections above gives us the following results: an independent SB for each of the HECO Companies would have lowered the operating expenses in 2016 for HECO by $7.8 million and increased that of MECO and HELCO by $1 million and $0.5 million, respectively. The significance of this cost reduction will grow over time as existing generation from the HECO Companies retires and is increasingly replaced by generation from IPPs.

In a scenario where an independent SB takes on the planning and procurement responsibilities for all three incumbent IOUs and is sized the same as the SB for HECO discussed above, the total cost reductions would have been approximately $17 million a year.

Figure 35. SB (outside) – Illustrative Impact on Operating Expenses (based on 2016 data)

($000s)	HECO	MECO	HELCO	Combined
SB Expenses				
O&M	9,738	4,929	5,599	9,738
Office Rent	279	46	81	279
Audit	15	15	15	15
IOU Cost Savings				
O&M	4,869	2,465	2,800	10,133
Purchased Power	12,930	1,521	2,431	16,882
Net Impact	(7,767)	1,004	465	(16,983)

Source: LEI analysis.

5.3 IOU to Single Buyer (Within the Utility)

A variation of the SB model is one in which the SB is a ring-fenced entity that resides within the existing IOU. A good example of this is the SB within Tenaga Nasional Berhad (see textbox below). With separate accounts and IT infrastructure such as emails, its operations and costs are clearly separated from the rest of the utility. However, it does share some resources with the IOU such as human resources, legal counsel, and the staff maintaining the accounts and IT systems. These costs will remain with the broader IOU.

The administrative expenses shown in Figure 37 below include the costs associated with the salaries for administrative staff, office supplies, property insurance, hiring outside advisory services, regulatory commission, and rent that are attributed to the departments responsible for planning and procurement.

Figure 36. Planning – Administrative Expenses

2016/2017 budgeted ($000s)	HECO	MECO	HELCO
Administrative expense	1,021	220	126

Source: HECO-1101, DOCKET NO. 2016-0328; MECO-702, DOCKET NO. 2017-0150; and HELCO-602, DOCKET NO. 2015-0170.

Tenaga Nasional Berhad's Single Buyer

Tenaga Nasional Berhad ("TNB") is the largest electricity utility in Malaysia and southeast Asia. TNB operates along the entire electricity supply value chain – from generation to distribution. TNB's business is categorized into five business entities, namely TNB generation, Single Buyer, Transmission, Grid System Operator, and Distribution Network. Except for TNB Generation, all the other business entities mentioned above are regulated by the Commission while the TNB generation costs are recovered according to established contracts for sale of electricity with the SB.

The SB is responsible for procuring electricity and related services, including scheduling, procuring, and settlement and its operations are governed by the Malaysian Grid Code and the SB Rules. The objectives of the SB are to minimize the cost of electricity procurement to meet demand, to promote transparency in the procurement of electricity, to facilitate competition in the generation sector and promote confidence in the electricity industry, and to facilitate security of electricity supply by proactively reporting any issues.

The SB (as well as the Grid System Operator ("GSO")) are ring-fenced entities from the other regulated and non-regulated business entities and operations of TNB, such that the managements of the SB and GSO are capable of acting independently from other activities of TNB. Below are some of the ring-fencing mechanisms (not exhaustive) that the SB abides by:

- SB employees shall ultimately only report to the Head of Single Buyer and shall not simultaneously hold any other position with TNB or in other IPPs.
- SB cannot disclose any information that is confidential to TNB or any other party
- SB shall be physically separated from other divisions and units of TNB and shall have separate work areas with access controls that prevent personnel other than employees of the SB from accessing the work areas of the SB
- Members other division or unit of TNB visiting the SB shall be considered as external visitors and may only enter into work areas of the SB when accompanied by employees of the Single Buyer
- SB shall have its own corporate identity and branding, including its own logo, corporate colours, uniforms, letterheads, business cards, website
- SB shall implement additional security protocols over any highly sensitive and confidential information originating from or relating to SB's functions SB shall maintain a separate set of Single Buyer Accounts relating to the performance of its functions as the Single Buyer and ensure any costs shared between the Single Buyer and any other divisions and units of TNB are allocated fairly and consistently

SB's back office finance functions (such as invoice and payment processing, records keeping) and human resource functions (maintenance of employee files, payment of salary, etc.) are outsourced to the Group Finance and Human Resources Division of TNB, respectively. SB enters into a Service Level Agreement with these two TNB entities.

Sources: Guidelines on Ring-fencing Practices and Procedures for Single Buyer (Peninsular Malaysia); Single Buyer Rules Version 2.0 (January 2015); Electricity Tariff Regulatory Implementing Guidelines (January 2012).

Likewise, the ring-fenced SB can be audited alongside the rest of the utility. A separate financial audit and resulting costs of $15,000 a year can be avoided.

An SB within the utility would pass on its revenue requirement to that of the IOU (and then to the ratepayers), whereas an independent SB would be funded through fees collected from them. An independent SB's expenses are essentially pass-through costs for the utility. But the IOU would include in its rate base the assets of a ring-fenced SB, increasing its total rate base. Its incremental earnings from the ring-fenced SB assets are estimated in Figure 38.

The Project Team assumes that a ring-fenced SB would achieve similar efficiency gains as an independent one if its separation from the rest of the IOU is strictly enforced.

Figure 37. Incremental Estimated IOU Earnings from SB Capex

($000s)	HECO	MECO	HELCO
Initial Capex	3,140	514	913
WACC	8.28%	8.05%	8.44%
Additional Earnings	260	41	77

Source: Section 5.2.1.2, Section 4.1.

The table below (Figure 39) provides preliminary estimates of the impact of a ring-fenced SB entity on ongoing opex of the incumbent IOUs. It indicates that such an SB would have lowered the HECO's opex in 2016 by approximately $8 million but increased the 2016 opex for both MECO and HELCO by $0.9 million and $05 million respectively. This disparity is due to the large size of HECO, where the potential savings in power supply costs are large enough to offset the operating costs of the SB entity.

Figure 38. SB (within the utility) – Illustrative Impact on 2016 Operating Expenses

($000s)	HECO	MECO	HELCO
SB Expenses			
O&M	8,717	4,709	5,473
Office Rent	279	46	81
Incremental IOU earnings	260	41	77
IOU Cost Savings			
O&M	4,359	2,355	2,737
Purchased Power	12,930	1,521	2,431
Net Impact	(8,033)	920	464

Source: LEI analysis.

6 Conclusion

Any changes in ownership models will result in significant upfront costs to establish a new organization (either a co-op or an SB) and to either acquire the incumbent IOU's assets in the case of a co-op or set up new office facilities for an SB. Even after operations commence under the new model, there are some incremental ongoing expenses. However, each transition of ownership model offers avenues for cost reductions with respect to the current IOU structure. A utility in a co-op model will face lower capital costs and is exempt from federal income tax liabilities. Likewise, the purchased power expenses are expected to be lower for a utility relying on an SB entity for planning and procurement. LEI will evaluate the net impact of savings and additional expenses of moving to another ownership model in Tasks 1.6.2, 1.6.3, and 1.6.4.

7 Appendix A: Scope of work to which this deliverable responds

Task 1.4.2 Economic evaluation of ownership and operation of each ownership model.

CONTRACTOR shall provide an economic evaluation of ownership and operation, including assumptions and derivations as to the potential acquisition costs, severance costs, operating and maintenance costs, likely annual capital investments and costs, power supply sources and costs, startup and other nonrecurring costs, information technology infrastructure, software systems, call center, lost tax revenues, lost franchise revenues and other key variables.

DELIVERABLE FOR TASK 1.4.2 CONTRACTOR shall provide all work related to developing an economic evaluation of the costs of ownership and operation of these facilities by ownership model based on current economic data in categories from 1.4.2. CONTRACTOR shall include cost estimates for acquisition, potential severance costs, start-up costs, the impact of lost tax revenues and/or franchise revenues, and other potentially relevant items. CONTRACTOR shall provide a table that summarizes the range of potential changes in the costs of ownership and operation by ownership model and their total magnitude in MS Excel with supporting documentation. CONTRACTOR shall submit deliverable for TASK 1.4.2 to the STATE for approval.

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Assessment of the potential of each ownership model to drive growth of DERs

prepared for Hawaii Department of Business Economic Development and Tourism by London Economics International LLC

April 6, 2018

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This document is one of several working papers issued as part of this engagement. The change in the utility ownership models is not considered as a key driver of the deployment of distributed energy resources ("DER"). Nevertheless, a change in the ownership would have some impact on the amount of DER in terms of the ease of access of the DERs to the system, the utility's access to resources, and the utility's strategic goals.

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List of acronyms

CGS	Customer Grid Supply
DBEDT	Department of Business, Economic Development, and Tourism
DER	Distributed energy resources
DG	Distributed generation
DR	Demand response
EV	Electric vehicle
HECO	Hawaii Electric Company
HELCO	Hawaii Electric Light Company
IOU	Investment-owned utility
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company
NARUC	National Association of Regulatory Utility Commissioners
NEM	Net Energy Metering
PSIP	Power System Improvement Plans
PUC	Public Utilities Commission
PV	Photovoltaic
RPS	Renewable Portfolio Standards
SB	Single Buyer

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1 Executive Summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which responds to Task 1.5.1 in the project scope of work, discusses the potential for each model to increase the penetration of Distributed Energy Resources ("DER").

DERs are generation resources that are interconnected to the distribution grid, located close to the customers, and generally small in scale. DERs include distributed generation, energy storage, demand response, energy efficiency, and electric vehicles. There are several advantages of DERs namely providing greater reliability to the grid, delaying or avoiding infrastructure investments, and offsetting emissions to name a few.

The HECO Companies project positive growth in DERs in their service areas in the next several years:[1]

- Distributed generation will grow between 1.7 and 3.0 GW by 2045;
- Energy storage will reach 1.15 GWh by 2045;
- Demand response will increase by an average of 14% per year from 2017 to 2045 to more than 1,500 MW by 2045;
- Energy efficiency will increase by an average of 3.8% per year from 2017 to 2045 or from 1,337 GWh in 2017 to more than 3,770 GWh by 2045;[2]

Likewise, Kauai Island Utility Co-operative ("KIUC") is positive that DER penetration will increase in the next few years with an additional 5 MW of customer solar under construction or permitted.[3] Moreover, electric vehicles in Hawaii have increased 50 times over the last decade from 108 EVs in 2006 to nearly 6,000 EVs in 2017.[4]

The key drivers of DER deployment include supportive policies and regulations in terms of incentives to encourage DERs, rate design, and interconnection; decline in costs; technology

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[1] Hawaii Electric, Maui Electric, and Hawaii Electric Light ("HECO Companies"). *PSIP Update Report*. Book 3, pages J-45 to J-49, J-60 to J-69, J-102 to J-108. December 23, 2016.

[2] Note: Hawaii's Energy Efficiency Portfolio Standard established a goal of reducing electricity use by 4,300 GWh by 2030. The HECO Companies' forecasts beyond 2030 are not hard targets mandated by law.

[3] KIUC. *Kauai's Renewable Energy Projects*. Access Date: February 13. 2018. Website. Available online at <http://website.kiuc.coop/content/renewable-energy-projects>.

[4] State of Hawaii Department of Business, Economic Development and Tourism. "Data Warehouse." *Research & Economic Analysis Division, State of Hawaii Department of Business, Economic Development and Tourism.* http://dbedt.hawaii.gov/economic/datawarehouse/.

improvements; and access to financing. In Hawaii, policies and incentives are already in place to make DERs more attractive. For instance, the regulatory framework includes revenue decoupling to encourage the utilities to pursue clean energy objectives. Capital costs for distributed generation such as solar PV have also decreased significantly in the past several years which encourages more DER deployment. DER technology performance has also been improving, benefiting both the utilities and consumers.

The change in utility ownership models is generally not considered as a key driver of DER deployment. Nevertheless, a change in utility ownership would have some impact on the amount of DER in terms of the ease of access of the DERs to the system and the fair treatment of these assets. Among the four ownership models reviewed, the Project Team anticipates that the cooperative ("co-op") and the two Single Buyer ("SB") models would provide the most positive impacts on DERs, more specifically on distributed generation ("DG") and energy storage; DERs like DG and storage could be owned by customers, third parties, or the utility. This is due to the SB's independence: it is assumed that it will not have any bias with regards to the procurement, or facilitation, of interconnections to DG and energy storage. Likewise, a co-op which is ultimately governed by its members would be motivated to implement goals that would be beneficial not only to the utility but also consistent with the underlying policy objectives of its region. Under the investor-owned utility ("IOU") ownership model, there is likely a positive impact on demand response ("DR") programs as well as electric vehicles ("EV") since it is assumed that IOU would have more resources and staff to implement these programs and capital investments on EVs would have the motivation to increase stakeholder value. Figure 1 shows the impact of the change in the ownership model to the DER as well as the energy security and reliability.

Figure 1. Impact of change of ownership model to the DERs and the energy security and reliability

Change of the Ownership Model	Distributed generation	Energy storage	Demand response	Energy efficiency	Electric vehicles	Energy security and reliability
Move to IOU	—	—	↑	—	↑	—
Move to cooperative	↑	↑	↓	↑	—	—
Move to Single Buyer (within the utility)	↑	↑	—	—	—	—
Move to Single Buyer (outside of the utility)	↑	↑	—	—	—	—

Furthermore, the change in utility ownership will not impact the energy security and reliability policies and regulations are already in place to ensure that achieving the RPS targets will not cause any issues with the system. There are compliance requirements that the utilities need to fulfill and performance standards that they need to monitor, regardless of the ownership type.

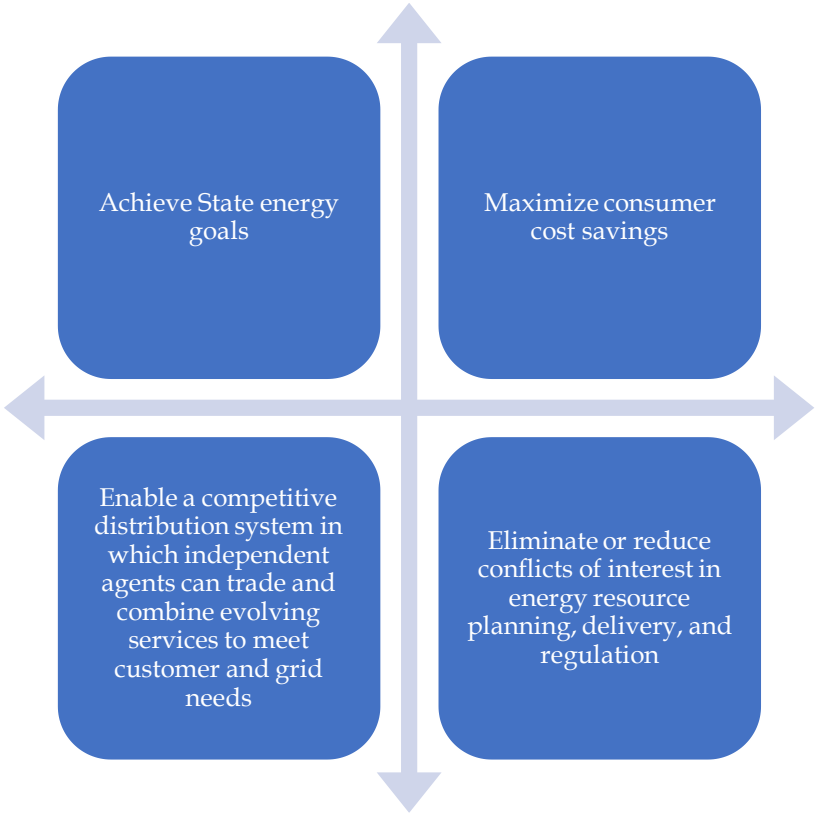
Finally, it is crucial to recognize that if appropriate regulatory structures and incentives are put in place, higher DER penetration and deployment will be achievable under any ownership model.

2 Introduction and scope

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. LEI, through a competitive sealed proposals procurement,[5] was contracted to perform this study.[6]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[7] listed in Figure 2.

Figure 2. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In

[5] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[6] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[7] House Bill No. 1700 Relating to the State Budget.

addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[8]

This deliverable is responsive to Task 1.5.1 in the project scope of work. It evaluates the different electric utility ownership models with respect to their potential impact on DERs, DR programs, system security, reliability, and resilience, to meet Hawaii's Renewable Portfolio Standards ("RPS"). It should be noted that the analysis of differences between ownership models is based on publicly available information.

[8] Hawaii Contract No. 65595. Scope of Services.

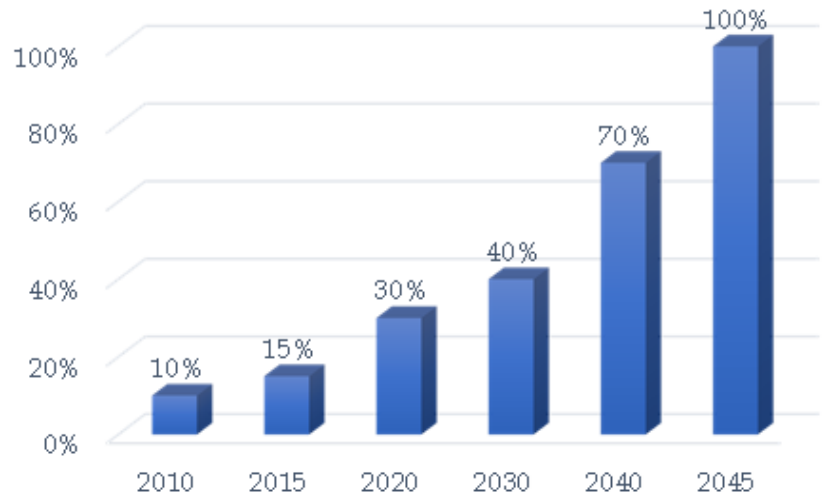
3 Overview of the current RPS requirements and distributed energy resources in Hawaii

Meeting the Hawaii State energy goals in the electricity sector requires the deployment of a full suite of solutions targeting supply-side and demand-side resources. The renewable energy targets set in the RPS direct the utilities to increase renewable generation installed capacity, both utility-scale and customer-sited. Increasingly, these resources will be backed by energy storage, as battery costs continue falling. As smart-grid technologies become more sophisticated, utilities can use energy efficiency and demand response programs for grid services while also offering customers additional opportunity to lower their energy bills. They can make utility operations more flexible, increase visibility into grid activity, and help integrate variable renewable generation in greater quantities.

3.1 The Hawaii RPS requirements and status

Hawaii is the first state with a legislative goal of achieving 100% renewable energy. On June 8th, 2015, the State passed Act 97, Session Laws of Hawaii 2015, amended section 269-92, Hawaii Revised Statutes (proposed as House Bill 623) to increase its RPS target from 40% by 2030 to 100% by 2045. The law applies to all electric utilities that sell electricity for consumption in the state and sets interim targets for net electricity sales as shown in Figure 3 below.[9]

Figure 3. RPS targets



Source: House Bill No. 623

[9] House of Representatives, Twenty-eighth legislature, 2015, State of Hawaii. *H.B. No. 623. A Bill for an Act Relating to Renewable Standards.* June 8, 2015.

According to the law, renewable electrical energy means (i) electrical energy generated using renewable energy as a source and beginning January 1, 2015, includes customer-sited grid-connected renewable generation , and (ii) electrical energy savings brought about by:

- Use of renewable displacement or off-set technologies (including solar water heating, seawater air-conditioning district cooling system, solar air-conditioning, and customer-sited, grid-connected renewable energy system; or

- The use of energy efficiency technologies, including heat pump water heating, ice storage, rate-payer funded energy efficiency programs, and use of rejected heat from co-generation and combined heat and power systems, excluding fossil-fueled qualifying facilities that sell electricity to electric utility companies and central station power projects.

The types of electricity generation that count towards the RPS targets include:[10]

- wind,
- solar,
- hydro,
- biogas (including landfill and sewage-based digester gas),
- geothermal,
- ocean-based (currents, waves, etc.),
- biomass,
- biofuels, and
- hydrogen produced from renewable energy sources.

The bill did add a provision that the means used to achieve RPS goals would have to benefit Hawaii's economy and consumers, maintain affordability, and not artificially increase the price of renewable energy in the state.[11]

Affiliated electric utilities can aggregate their renewable portfolios to achieve the targets, so Hawaii Electric Light Company ("HELCO"), Maui Electric Company ("MECO"), and Hawaii Electric Company ("HECO"), jointly referred to as the HECO Companies in this document, can add their electricity sales from renewables to jointly achieve the goals.

Part of the Action Plans of the HECO Companies to achieve the 100% RPS target includes efforts to maximize the DER and utilize demand response programs.[12] In its 2016 Power Supply Improvement Plans ("PSIP"), the HECO Companies stated that they "plan to maximize integrating DER and DR resources and begin efforts to procure grid-scale resources." Deployment of DER resources is the focus of this memo and will be discussed in the next sections.

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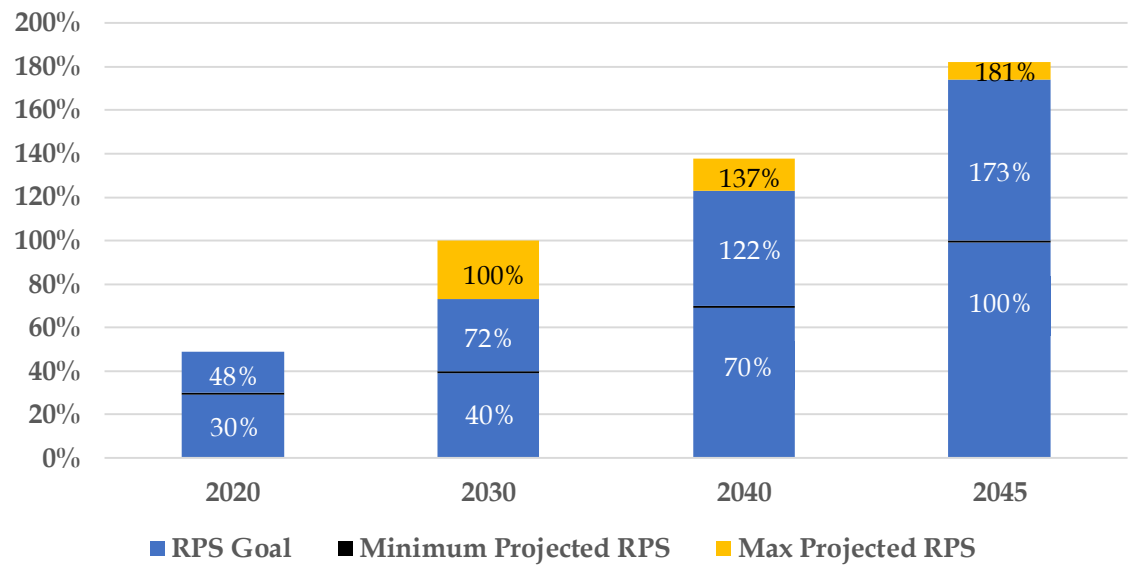
[10] 2009 Hawaii Code. *Part V. Renewable Portfolio Standards. §269-91 [Definitions.].*

[11] House Bill. 623. *A Bill for an Act Relating to Renewable Standards.* June 8, 2015.

[12] HECO Companies. *PSIP Update Report.* Book 1, page ES-2. December 23, 2016.

In their annual reports submitted to the PUC, the HECO Companies and Kauai Island Utility Co-operative ("KIUC") indicate that they are on track to achieve the RPS targets given the current regulations.[13] The HECO Companies' proposed plan described in the 2016 Power Supply Improvement Plans ("PSIP") looks to accelerate their RPS attainment further, and reach 100% renewables by 2040, five years ahead of schedule. The PSIP action plan will help them exceed 50% RPS by 2021 and enable Molokai to achieve 100% renewable energy by 2020.[14] Figure 4 shows RPS target and the projected RPS of the subsidiaries of the HECO Companies.

Figure 4. Projected RPS - HECO Companies, consolidated



Source: HECO Companies 2016 RPS Status Report.

Likewise, KIUC's 2016 RPS of 41.66% already surpassed the 30% RPS target by 2020 by more than 11% as well as the 2030 RPS requirement by nearly 2%. With its ongoing plans, KIUC is confident that it will be able to exceed the next RPS requirement of 70% by 2040.[15] Figure 5 shows the RPS Status of the HECO Companies and KIUC in 2016.

[13] The Project Team wants to note that there was a new bill, House Bill 1801, that proposes to change the formula that calculates Hawaii's percentage renewable energy used by the state from electricity sales to electricity generated. The HECO Companies opposed the bill stating that it is unfairly increasing its risk of not achieving the renewable target. The section regarding RPS calculation has since been deleted from the bill.

[14] HECO Companies. *PSIP Update Report*. Book 1, page ES-2. December 23, 2016.

[15] KIUC. *KIUC's Annual RPS Status Report for the year ending December 31, 2016 (Docket No. 2007-2008).* April 11, 2017.

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Figure 5. RPS status of the utilities as of 2016

	HECO	HELCO	MECO	HEI Consolidated	KIUC
RPS %	19.4%	54.2%	36.9%	25.8%	41.7%

Source: HECO Companies 2016 RPS Status Report; KIUC 2016 RPS Status Report.

3.2 Distributed Energy Resources

Although different entities and markets have various ways of defining DERs (Figure 6) and aspects of what constitutes a DER, most of the definitions have the same basic characteristics,[16] which include the following:

- a resource located close to the customers;
- interconnected to the electric grid, in an approved manner, at or below IEEE medium voltage (69 kV);
- generate electricity using any primary fuel source; and
- small in scale.

Figure 6. Different definitions and technologies considered as DER

Entity	DER definition and technologies
Electric Power Research Institute ("EPRI")	DERs are electricity supply sources that fulfill the first criterion, and one of second, third or fourth criteria: Interconnected to the electric grid, in an approved manner, at or below IEEE medium voltage (69 kV), generate electricity using any primary fuel source, store energy and can supply electricity to the grid from that reservoir and involve load changes undertaken by end-use (retail customers specifically in response to price or other inducements or arrangements)
National Association of Regulatory Utility Commissioners ("NARUC")	DERs are defined by the following components: the resource is connected to the distribution grid and not the bulk transmission system; a relatively small resources, certainly under 10 MW but generally smaller; and generally not individually scheduled by an RTO or ISO
Lawrence Berkeley National Laboratory ("LBNL")	DERs include clean and renewable distributed generation systems (such as high-efficiency combined heat and power and solar photovoltaic systems), distributed storage, demand response and energy efficiency. Plug-in electric vehicles are considered as part of distributed storage.
Massachusetts	DER is a device or measure that produced electricity or reduces electricity consumption, and is connected to the electrical system, either "behind the meter" in the customer's premise, or on the utility's primary distribution system
Hawaii	DER are modular electric generation or storage located near the point of use and can

Sources: Electric Power Research Institute and NARUC

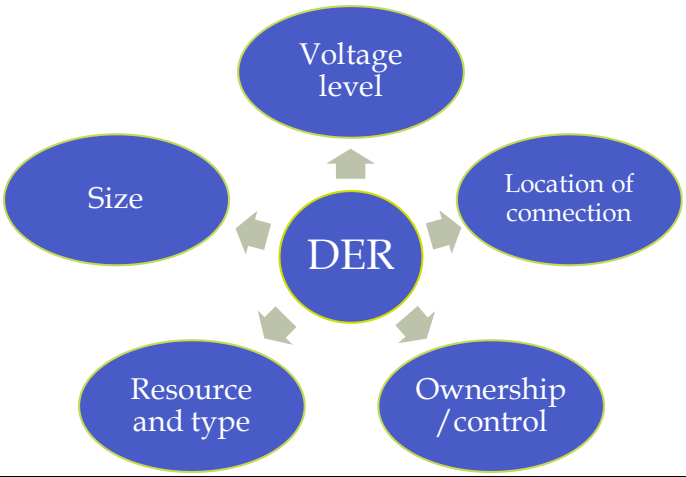
A definition of DER may be crafted from answering the following questions:

- What is the desired voltage level of connection?

[16] NARUC. *NARUC Manual on Distributed Energy Resources Rate Design and Compensation*. November 2016. Page 45.

- Where will deployments exist with respect to the meter?
- Who owns and controls the resources?
- What type of resources are included? More specifically, are both renewable and non-renewable resources included? How about generation and/or storage?
- What capacity threshold is being considered?

Figure 7. DER definition variables



For this paper, DER is defined as modular electric generation located near the point of use; it can either be grid connected or operated independently of the grid; and it can be customer-owned or utility-owned. Technologies such as distributed generation, energy storage, demand response, energy efficiency, and electric vehicles are considered as DERs.

DERs provide several categories of benefits. They provide positive net value to the grid such as deferring or avoided infrastructure investments in generation, transmission, and distribution systems. They support the grid by providing greater reliability, improving the resilience, and providing voltage/VAR control, spinning reserve, regulation, or other ancillary services. DERs could also offset emissions and provide other environmental benefits. For the State of Hawaii, DERs can reduce its dependence on imported oil and help its energy security especially during natural disasters or other emergencies.

The different DER technologies, their benefits, status, trends (if available), and programs in the State are discussed in the subsections below.

3.2.1 Distributed generation

Distributed generation ("DG") is defined by the US Department of Energy as "electric generation that feeds into the distribution grid, rather than the bulk transmission grid, whether on the utility side of the meter or the customer side." [17] DGs include several types of technologies such as solar

[17] US Department of Energy. *The Potential Benefits of Distributed Generation and Rate-Related Issues that May Impede Their Expansion*. February 2007. Page xvi.

photovoltaic panels, small wind turbines, fuel cells, combined heat and power, and emergency backup generators, to name a few. DG is expected to be primarily solar PV in Hawaii.

Potential benefits of the DG include increased electric system reliability, reduction of peak power requirements, provision of ancillary services, improvements in power quality, reductions in land-use effects and rights-of-way acquisition costs,[18] energy security,[19] infrastructure resilience, and reduction in emissions, to name a few. Nevertheless, high levels of DG penetration can also generate technical risks at the distribution grid and reliability challenges for the entire electricity system.

DGs are subject to a variety of local, state, and federal policies. In Hawaii, the Net Energy Metering ("NEM") and Customer Grid Supply ("CGS") programs helped in the rapid growth of the rooftop solar penetration. In fact, rooftop solar penetration grew so fast under NEM that the Hawaii Public Utilities Commission ("PUC") capped the HECO Companies' NEM program and transitioned to CGS, which compensated the customers for energy exported back to the grid at lower than the retail rate. Customers under the self-supply tariff could not export energy to the grid.

In October 2017, the PUC approved two new programs for the HECO Companies that would continue to allow customers to install rooftop solar and receive monetary compensation, while also support the utilities to manage the DER integration more smoothly. These are the Smart Export program and the Controllable CGS program. Under the Smart Export program, customers with rooftop solar combined with battery storage would receive monetary credits on their bills for power exported to the grid during non-daylight hours. Similarly, customers with solar but no storage can receive credits for energy exported to the grid under the Controllable CGS program, where the utility can control the output from the customer's system to maintain a stable grid.[20]

Based on the HECO Companies' PSIP Update Report,[21] rooftop solar is forecast to grow rapidly to reach between 1.7 and 3 GW by 2045 for the market DG-PV and High DG-PV forecasts, respectively, as shown in Figure 8. This increased capacity will be supported by behind-the-meter storage.

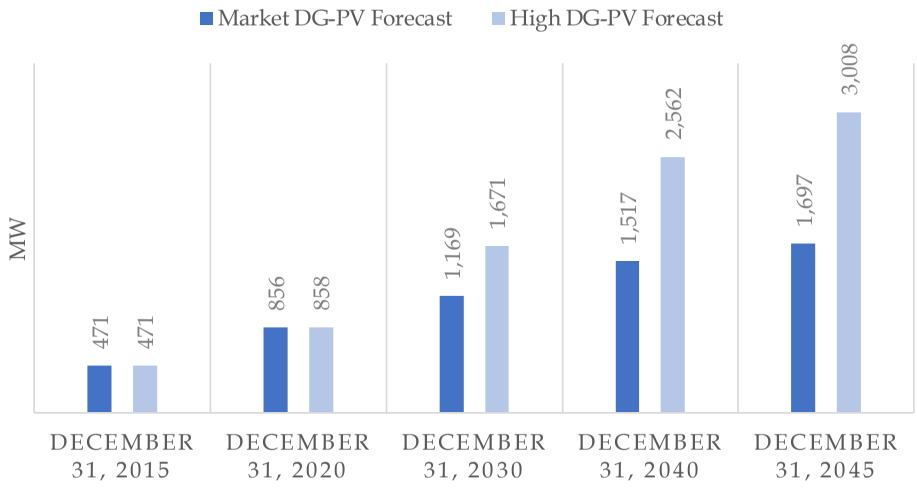
[18] Ibid.

[19] Example, reduction in vulnerability to terrorism.

[20] Hawaii Public Utilities Commission. *HPUC Expands Options for Customers to Install Rooftop Solar and Energy Storage.* October 20, 2017.

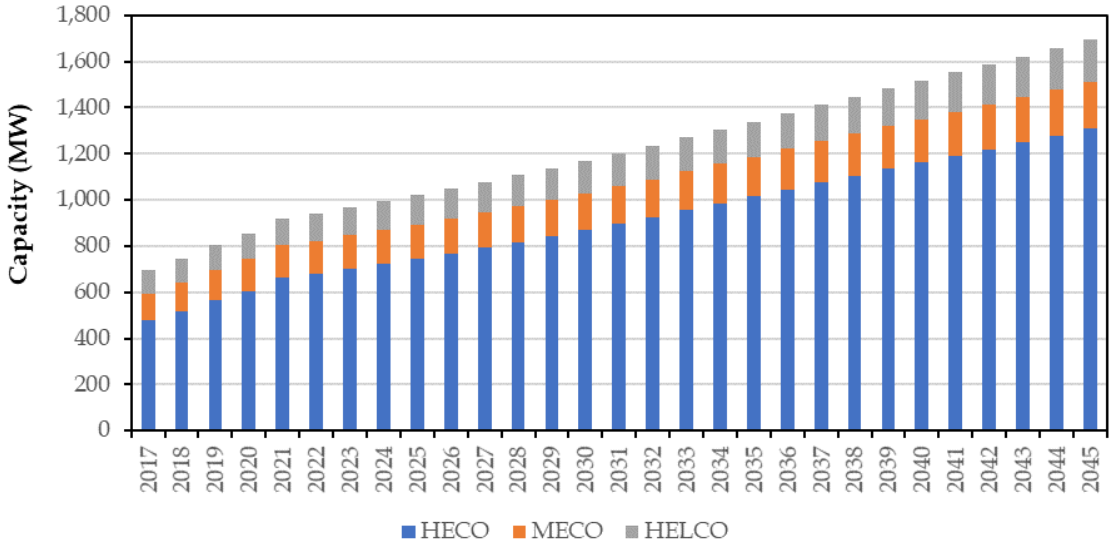
[21] HECO Companies. PSIP Update. Book 3, pages J-60-J69.

Figure 8. HECO Companies' projected DG-PV installed capacity



Source: HECO Companies. PSIP Update Report.

Figure 9. HECO Companies - forecast cumulative DG-PV capacity by subsidiary



Source: HECO Companies PSIP Update Report.

Figure 10. Existing rooftop solar capacity

	HECO	HELCO	MECO	KIUC
DG-PV (2017)	479 MW	103 MW	119 MW	22 MW

Source: HECO Companies. PSIP Update Report; KIUC website.

Although KIUC has fewer DG-PV compared to the HECO Companies, it has a substantially higher percentage of solar penetration compared to the other islands within the State. As of May

2017, KIUC has 22 MW of DG-PV.[22] There are an additional 5 MW of customer solar under construction or permitted.[23] The total cumulative residential rooftop solar installations are about 3,390 units, which represents nearly 13% of KIUC customers.[24] Although KIUC does not have any publicly available forecasts of DG-PV capacity,[25] KIUC said in its DER proposal (Docket No. 2014-0192) to Hawaii PUC that it can "prudently accept only a limited amount of additional energy resources onto its system, including non-direct-to-grid resources (e.g., DER systems)."[26] The total curtailment of its cost-effective KRS One and KRS Two facilities[27] totaled about 742 MWh of energy in 2016, which shows that, from an operational perspective, KIUC cannot accept any more mid-day direct-to-grid energy without creating more curtailment.[28] According to KIUC, "any program (such as new or expanded DER programs) that requires the purchase of mid-day to direct-to-grid energy is not in the public interest with respect to KIUC and its member-customers."[29] To address this challenge, KIUC proposed to revise its current Schedule Q rate schedule by replacing the Non-Export and Export options with Customer Self-Supply and Smart Export options. This will be discussed in detail in Section 4.1.2.

3.2.2 Energy storage

There are different types of energy storage, and they are generally grouped into three (3) categories: (i) mechanical (hydro pumped storage, compressed air energy storage, and flywheels), (ii) thermal (ice storage), and (iii) chemical (batteries). Energy storage technologies have different applications for the entire power sector chain - from generation to end-user. Storage systems improve the reliability of electricity supply, increase the efficiency of existing power plants and transmission facilities, and delay or reduce the investment required in these facilities. They can also reduce emissions by providing electricity during peak demand and replacing fossil-fueled peaking plants. Lastly, energy storage technologies facilitate the integration of renewables in the

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[22] KIUC. *KIUC's Initial Statement of Position on Deferred Issues and Technical Track Issues and in Support of its Comprehensive Proposal*. KIUC System Statistics. Attachment A, page 7 of 34. May 18, 2017.

[23] KIUC. *Kauai's Renewable Energy Projects*. Access Date: February 13. 2018. Website. Available online at <http://website.kiuc.coop/content/renewable-energy-projects>.

[24] KIUC. *2016 Annual Report*. page 8.

[25] LEI inquired through email if KIUC had forecasts of DG-PV capacity. We were informed on December 13, 2017 that they do not have any DG targets/forecasts.

[26] KIUC. *KIUC's Initial Statement of Position on Deferred Issues and Technical Track Issues and in Support of its Comprehensive Proposal*. Docket No. 2014-0192. Page 4.

[27] KIUC Renewable Solutions One LLC (KRS One) and KIUC Renewable Solutions Two LLC (KRS Two) were created to construct, own, and operate a photovoltaic (PV) facility for selling the renewable energy produced by the PV facility to KIUC for use in the KIUC's operations. See *KIUC Consolidated Financial Statements December 31, 2016 and 2015* (page 8).

[28] KIUC. *KIUC's Initial Statement of Position on Deferred Issues and Technical Track Issues and in Support of its Comprehensive Proposal*. Docket No. 2014-0192. Page 5.

[29] Ibid, page 5-6.

power system and increase these renewable resources' value by storing wind generation during off-peak hours and supplying that power during peak hours.

Some countries and states in the US (such as California) see the value of energy storage and have established initiatives to promote the deployment of energy storage. For instance, California has a law that requires utilities and the regulator to set mandatory procurement targets for energy storage.

In the territories served by the HECO Companies, the penetration of customer-sited storage is very low – only 5 MWh across their service areas.[30] However, as costs decrease rapidly, storage will also experience a similar growth as solar PV and is projected by the HECO Companies to reach 1.15 GWh by 2045.[31] According to the HECO Companies, a majority of this capacity, nearly two-thirds, will be in Oahu. Figure 11 shows the HECO Companies' projected behind the meter storage capacity while Figure 12 maps the locations of the planned and underdevelopment energy storage projects.

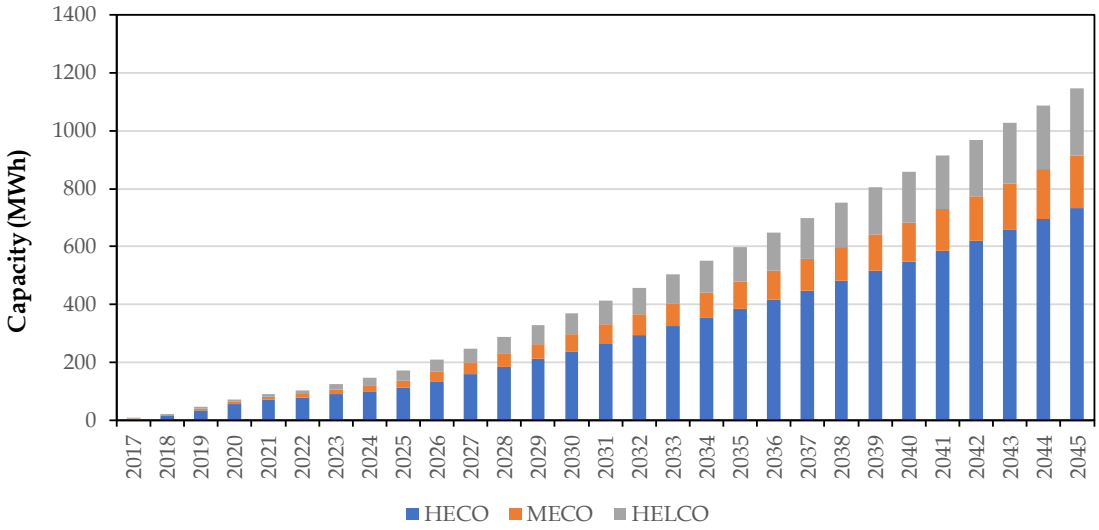
KIUC is also moving forward with its energy storage capacity. KIUC has battery energy storage and pumped storage projects under development. Last February 2018, AES Distributed Energy and KIUC broke ground on its Lawa'i Solar and Energy Storage Program. It is going to be the largest hybrid solar and storage project with a 28 MW solar battery energy storage and will provide 11% of KIUC's generation capacity and will also increase KIUC's percentage of renewables to 60%.[32] In addition to this, KIUC is moving forward with its planned 25-MW Pu'u Opae Pumped Storage Hydro Project. The proposed online date for this project is in 2023. Although these storage projects fall under the utility-scale category rather than DERs, their presence will increase KIUC's operational flexibility to manage reliability and thus allow it to integrate more DERs on to the system.

[30] HECO Companies. *PSIP Update Report*. Book 3, December 23, 2016.page J-65 to J-69.

[31] Ibid.

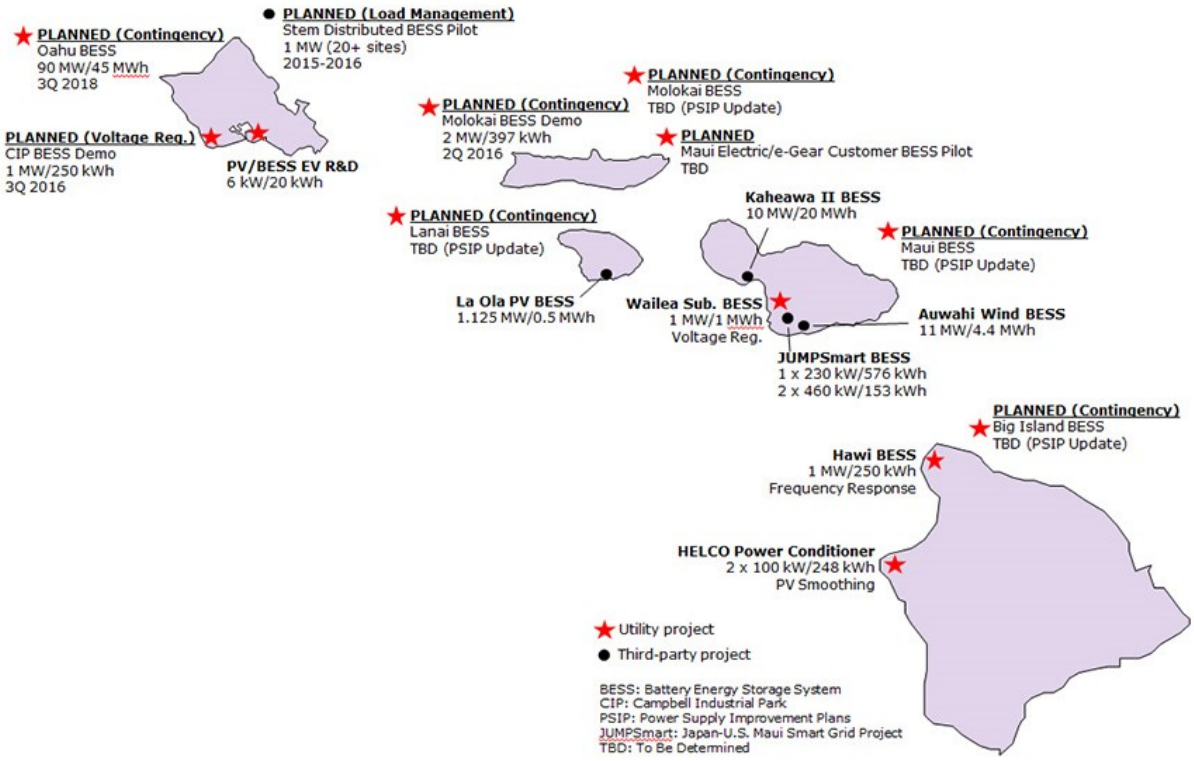
[32] KIUC. *Press Release: KIUC and AES Distributed Energy Announce Plan to Construct Innovative Renewable Peaker Plant on Kauai Utilizing a Hybrid Solar and Battery Storage System*. January 10, 2017.

Figure 11. The HECO Companies' forecast cumulative behind-the-meter storage capacity



Source: HECO Companies. PSIP Update Report.

Figure 12. Location of the HECO Companies' planned/under development energy storage



Source: HECO Companies website (Accessed on March 5, 2018)

3.2.3 DR programs

Demand response entails reducing one's electricity usage during times of high electricity demand, or when the reliability of the system is threatened, in response to financial incentives.

DR programs provide a variety of benefits. As variable generation from renewable resources both in-front-of- and behind-the-meter constitute a larger share of Hawaii State's generation portfolio, the utility or grid operator requires more flexible resources like DR to keep the system balanced. DR can be an especially effective tool in this regard because it offers operational flexibility and conserves energy by rewarding customers for changing their consumption behavior in response to supply variations. Furthermore, the PUC notes that DR programs could delay or eliminate the need for new fossil fuel units and help the utility to operate its system efficiently and at a lower cost.[33]

The PUC set the objectives for the DR programs that utilities need to comply with under Order No. 32054.[34] Specifically, the Order states that each program must provide quantifiable benefits to ratepayers and each program should provide one or more of the following benefits:

- reduce total energy consumed;
- reduce peak load;
- assist in balancing PV and wind generation variability;
- support reliable operation of the system;
- provide ancillary services; and
- provide opportunities for customers to have greater control over their energy use and lower their electricity bills.

The HECO Companies offer DR programs for both residential and commercial customers. These DR programs include providing a free device that can temporarily curtail loads.[35] The HECO Companies are also testing Open Automated Demand Response ("OpenADR") as part of the Fast DR pilot program. OpenADR is part of the Hospitality Study Project with the Electric Power Research Institute ("EPRI") and Lawrence Berkeley National Laboratory ("LBNL").[36] The study will generate data and knowledge on how to design DR programs for hospitality facilities in hot and humid climate like in Hawaii.

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[33] PUC. *Decision and Order No. 32054 - Order Regarding Demand Response Programs.* Filed April 28, 2014. Pages 7-11.

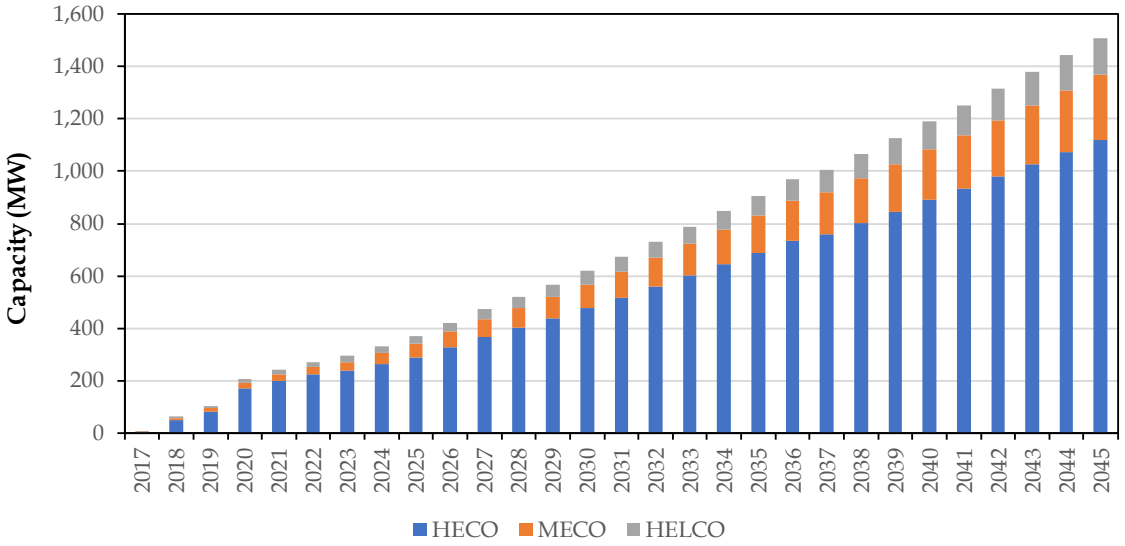
[34] PUC. *Decision and Order No. 32054 - Order Regarding Demand Response Programs.* Filed April 28, 2014. Pages 81-85.

[35] These include the Residential Direct Load Control Water Heater, RDLC Air Conditioner, Large Commercial and Industrial Direct Load Control, and Small Business Direct Load Control Program.

[36] HECO Companies. OpenADR Hospitality Industry R&D Project. Available online at https://www.hawaiianelectric.com/Documents/save_energy_and_money/demand_response/Hospitality_Study_EPRI_HECO_OpenADR_Flyer.pdf

Based on its PSIP, the HECO Companies include the assumption that DR will increase by an average of 14% per year until 2045. Figure 13 shows the forecasted cumulative DR capacity for the HECO Companies.

Figure 13. HECO Companies - forecast cumulative DR capacity



Source: HECO Companies. PSIP Update Report

KIUC, on the other hand, does not have any DR programs at this time. While KIUC acknowledges that there are benefits to incorporating DR, they do not believe that the effort required to implement DR would produce the kind of benefits that they have been able to achieve with their utility-scale projects.[37] Moreover, they believe that their efforts are better focused on large-scale projects such as the pumped storage hydro and the Lawai and Kekaha AES projects.[38] Nevertheless, this is not to say that KIUC will not consider DR at some point, but due to resource limitations (staffing costs, etc.), they have chosen to focus on other alternatives in the near term.[39]

3.2.4 Energy efficiency

Energy efficiency ("EE") refers to products and services intended to permanently reduce the amount of energy used by customers. This includes products (such as energy efficient appliances, building energy management system, efficient heating, and cooling system) and behavioral programs (e.g., customers are provided information to reduce energy use).

[37] Tokioka, Beth. KIUC Communications Manager. Email dated April 3, 2018.

[38] Ibid.

[39] Ibid.

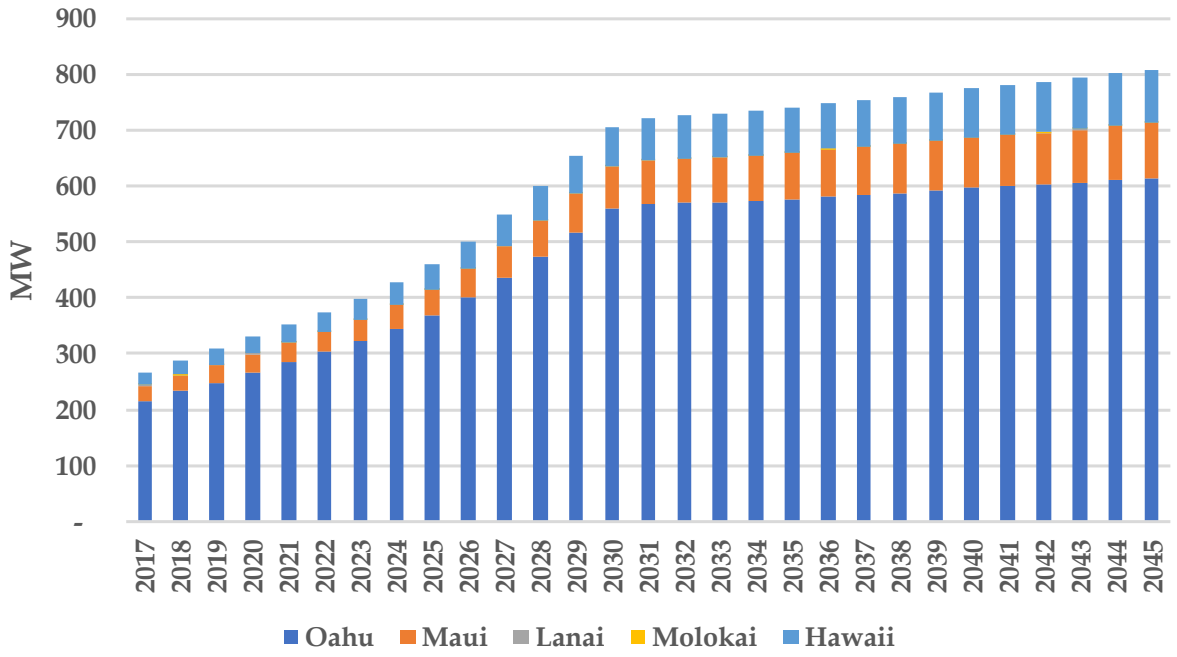
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Some of the benefits of energy efficiency include cost savings to customers, improved facility operations and building energy systems reliability, and reductions in future electricity rates. For Hawaii State, energy efficiency can also help the State achieve its 100% clean energy goals.

In 2007, the State established a Public Benefits Fund to promote the development of programs and services that increase energy efficiency, reduce electricity consumption and demand, and ultimately decrease the State's dependence on imported fossil fuels. A third-party administrator, called Hawaii Energy, manages the programs and services of the Fund under the oversight of the PUC. Hawaii's energy efficiency program provides financial incentives to procure a wide range of energy-efficient equipment which includes lighting, HVAC, appliances, roofs, window film, water heating, pumps, and motors. According to the 2016 Annual Report, the energy reductions achieved in 2016 Program Year will save an estimated equivalent of 2.9 million barrels of oil and 1.7 million tons of greenhouse gas emissions.[40]

The HECO Companies and KIUC encourage conservation and efficient use of energy resources. Some of their programs include home visits, heat pump water heater rebate, lighting program, solar loan program, solar rebate program, and new efficient appliance replacement rebate program, to name a few.

Figure 14. Projected cumulative EE installation by the island



Source: HECO Companies. PSIP Update Report.

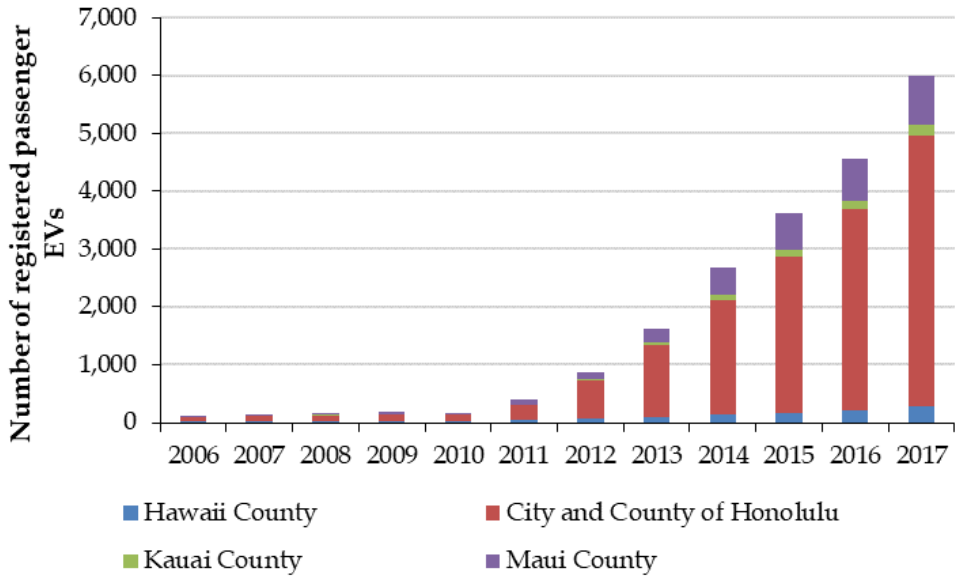
[40] Hawaii Energy. *Annual Report 2016 Program Year*. Page 7.

The HECO Companies project an average of 6.5% compound annual growth rate ("CAGR") for EE from 2017 to 2030 across the five islands they serve. From 2031 and onwards, the development of EE remains at a flatter rate of 0.8% per year. According to HECO Companies, these projections were aligned with historical average annual impacts achieved by the Public Benefits Fund Administrator, Hawaii Energy.[41] Also, the forecasts included the effect from Hawaii Energy's EE programs and changes to building and manufacturing codes and standards.[42]

3.2.5 Electric vehicles

EVs provide multiple benefits including reducing greenhouse gas and other conventional pollutants, operating quietly and cleanly, allowing home refueling and lowering operating and fuel costs. Battery from EVs can also be used as a storage device that can provide additional grid services.

Figure 15. Number of registered passengers EVs by county, 2006-2017



Source: DBEDT

EV adoption in Hawaii has been on the rise, climbing from 108 registered passenger EVs in 2006 to 5,987 in 2017.[43] Most recent estimates, as of February 2018, indicate that the number of passenger EVs has reached 6,890, an increase of 1,533 vehicles (or 28.6%) from the same month

[41] HECO Companies. *PSIP Update Report*. December 2016. Page A-21.

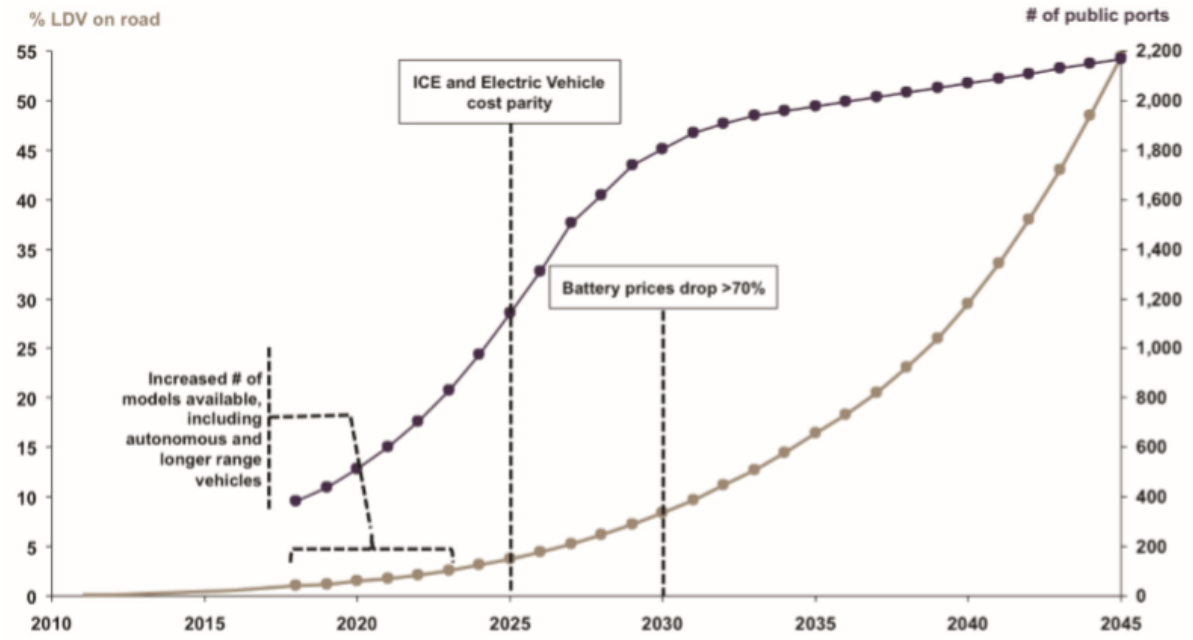
[42] HECO Companies. *PSIP Update Report*. December 2016. page J-24.

[43] State of Hawaii Department of Business, Economic Development and Tourism. "Data Warehouse." *Research & Economic Analysis Division, State of Hawaii Department of Business, Economic Development and Tourism.* http://dbedt.hawaii.gov/economic/datawarehouse/.

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last year, and an increase of 142 vehicles (or 2.1%) from January 2018.[44] Figure 15 tracks the growth in the number of registered passenger EVs across the state, during the 2006-2017 period. Ultimately, EV adoption will depend on the market's regulations, gasoline prices and battery costs, available charging infrastructure, and consumer preference.

Figure 16. HECO's personal light-duty EV adoption forecast for Oahu, 2010-2045



Source: HECO Companies. Electrification of Transportation Strategic Roadmap.

The use of EVs in Hawaii is encouraged as it helps reduce the need for imported oil and fossil fuel emissions. In fact, the government and the utilities are working hand in hand to promote its use. The HECO Companies have signed a memorandum of understanding with DBEDT, the Department of Transportation, and the Division of Consumer Advocacy that formed the Drive Electric Hawaii Initiative in December 2016.[45] This program aims to "pursue opportunities to enable lower-cost electricity and electric drive transportation options for residents and businesses in Hawaii through near-term investments that support long-term value to all electric customers."[46]

[44] State of Hawaii Department of Business, Economic Development & Tourism. *Monthly Energy Trend Highlights.* February 2018.

[45] The full list of signatories to the memorandum of understanding are: DBEDT, State of Hawaii Department of Transportation, State of Hawaii Division of Consumer Advocacy, Hawaiian Electric Company, Hawaii Electric Light Company, Maui Electric Company, Kauai Island Utility Cooperative, Blue Planet Foundation, Ulupono Initiative, and Rocky Mountain Institute.

[46] Drive Electric Hawaii Initiative "Memorandum of Understanding",

In addition, the HECO Companies released their strategic roadmap for the electrification of transportation on March 29, 2018. In this report, the HECO Companies described a future in which most light-duty vehicles will run with electricity from renewable resources such as solar, wind, biofuels, and geothermal. It also provided a forecast for light-duty EV adoption and load for Oahu. Oahu was focused on as an initial case study, as it currently accounts for 60% of registered, taxable passenger vehicles in the state. The HECO Companies forecast that 55% of personal light-duty vehicles on Oahu roads in 2045 will be fully electric, supported by approximately 2,200 public charging ports. The HECO Companies also have a DC Fast Charger program approved by the PUC designed to encourage EV ownership in their territories.

HECO's short-term strategy to optimize EV deployment:

1. Collaborate with automakers, dealerships, and advocates to (i) lower EV costs through rebates, and (ii) educate customers through initiatives such as: ride and drives, energy and EV fairs, sustainability forums, and EV WattPlan – an online tool that allows customers to compare EVs;
2. Accelerate the buildout of EV charging infrastructure, especially at multi-unit dwellings and workplaces, including DC fast chargers that employees can reserve for 15 minutes per day, 5 times per week;
3. Support the electrification of buses and other heavy equipment by reducing upfront costs and advising on charging solutions that are compatible with operations;
4. Incentivize EV charging to align with grid needs and reduce costs through demand response programs and time-of-use rates, such as Schedules EV-F and EV-U, which provide consumers with price signals to charge during low-cost periods; and
5. Coordinate with ongoing grid modernization efforts to ensure the smooth integration of EVs and maximize the use of renewable resources.

Source: Hawaiian Electric Companies. *Docket No. 2016-0168: Electrification of Transportation Strategic Roadmap*. March 29, 2018.

Likewise, KIUC is also doing its share to promote the use of EVs. In KIUC's March 2015 issue of Currents, the utility presented two options it was considering to *"encourage EV adoption to help members save money and to put more solar to use during the day."*[47] The first option cited by KIUC was the Time of Use pilot study. The second option entailed securing partnerships with private landowners to install Level 3 fast-charging stations across the KIUC service territory, with a particular focus on underserved areas such as the West Side and North Shore.[48]

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https://www.hawaiianelectric.com/Documents/about_us/news/2016/20161220_drive_electric_hawaii_mou_with_sig
natures.pdf , at 3.

[47] KIUC. *Currents*. March 2015.

[48] Ibid.

Also of note is a rebate offer that Nissan extended to ratepayers of the HECO Companies and KIUC purchasing the Nissan Leaf throughout 2017. Utility customers were offered a $10,000 rebate off the manufacturer's suggested retail price, with the program first introduced in January 2017, and then again in May 2017, with an expiration date of September 30, 2017.[49] For 2018, the rebate has been reduced to $3,000.

3.3 Ensuring system security and reliability with DER integration

In deploying and integrating high levels of DERs into the grid, there is a need to ensure system security and reliability. In its Decision and Order No. 22248, the PUC enumerated some items that must be taken into consideration with respect to DG and its implementation or interconnection. More specifically, the Decision stated that implementation of DG should not reduce the reliability or safety of the electric utility' distribution system. Likewise, it stated that the electric utility system must remain in balance at all times and customer-generators must coordinate generator additions with the distribution operator as new generation interconnections can affect system reliability.

The North American Electric Reliability Corporation ("NERC") defines system security as the ability of the system to withstand sudden disturbances or quickly regain stable operations when the electric power system is disturbed by temporary external forces. System stability can be characterized by frequency stability, voltage stability, and rotor angle stability. Frequency stability requires balancing real power supply and system demand under changing conditions. The HECO Companies, in its PSIP, mentioned that ancillary services would be able to help in maintaining stability in the system. More specifically, it acknowledged that there is "opportunity for DERs, DR, and energy storage to provide the ancillary services needed for a resilient, secure grid."[50]

The PUC put in place various regulations to ensure that achieving the RPS targets will not cause any issues with the system security and reliability. For instance, utilities are required to submit to the PUC, within 30 days after the close of the year, a statement affirming the sufficiency of capacity and the approach that was utilized to ascertain the required reserve capacity which forms the basis for future requirements in generation, transmission, and distribution plant expansion programs. For the HECO Companies, the reserve margin metric used in preparing its PSIP is assumed at 30% for Maui and Hawaii Island, and 45% for Oahu.[51] For KIUC, PUC's Order No. 24078 issued on March 6, 2008, stated that the adequacy of supply/reserve margin is based on KIUC having sufficient reserve capacity available to meet its evening peak load with its largest generator unit out for any reason and morning peak load with its largest generator unit out for any reason plus its third largest generator unit for scheduled maintenance.[52] Additionally,

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[49] KIUC. *Nissan Extends Rebate Offer to KIUC Members on the 2017 Nissan Leaf® Sedan.* June 6, 2017.

[50] HECO Companies. *PSIP Update Report*. Page. I-7.

[51] HECO Companies. *PSIP Update Report*. Book 4. December 23, 2016. Page J-7.

[52] KIUC. *2018 Adequacy of Supply Statement*. December 19, 2017. P. 1.

utilities are required to make reasonable efforts to avoid interruptions of service, but when interruptions occur, they should restore service within the shortest time practicable and in a safe manner. They are also required to inform the PUC as soon as possible if there are any interruptions affecting 1% or more of system peak load.[53]

Compliance with system reliability can be measured through the reliability standards laid out by the PUC. The HECO Companies and KIUC are required to file annual reliability reports, which include the following reliability indices:

- Average Service Availability ("ASA") measures the time that electrical service is available;
- Customer Average Interruption Duration Index ("CAIDI") gauges how long an interruption lasts;
- System Average Interruption Duration Index ("SAIDI") measures the time that the average customer was without power in a year; and
- System Average Interruption Frequency Index ("SAIFI") shows how often an interruption occurs.

Finally, modernizing the HECO Companies' transmission and distribution systems is required to be able to ensure reliable and safe integration of DERs. In the PSIP, the HECO Companies stated that "a modern, intelligent grid is necessary to operate an integrated system, support more renewables, optimize DER resources, and enable new products and services that provide value to customers."[54] Under the Grid Modernization Strategy, one of the items that they will do is to invest in infrastructure that is needed to address the service quality issues related to DER growth. Indeed, DER deployment necessitates a more dynamic network with advanced communications to ensure reliability, stability, and efficiency of the system. The HECO Companies submitted their final proposed Grid Modernization Strategy in August 2017, and it was conceptually approved by the PUC on February 7, 2018.[55]

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[53] HECO Companies. *PSIP Update Report*. Book 4. December 23, 2016. page 24.

[54] HECO Companies. *PSIP Update Report*. Book 1. December 23, 2016. page 2-28 .

[55] It is "conceptually approved" because the Commission's order does not constitute a final approval of the proposed expenditures. It stated that "After reviewing the strategy and public comments, the Commission has remaining questions about the proposed priority, implementation timing, and expected costs of each component" and that PUC expects answers when the utilities file one or more applications in the next few months to implement the six components of the Grid Modernization Strategy. These components include (i) customer-facing technology, (ii) advanced operational systems, (iii) distribution automation, (iv) technology to manage voltage, sensing and measurement equipment, (v) operational communications, and (vi) advanced operational systems.

4 Key drivers of the DER deployment

Jurisdictions with significant levels of DER adoption have demonstrated that key drivers of DER deployment include supportive legislative and regulatory policies, the decline in costs, and improvements in technology.[56,57] These are discussed in detail below.

Overall, these key drivers in the adoption of DERs can induce several benefits including, but not limited to:[58]

- ***Avoided costs:*** energy and demand bill management for customers;
- ***Resiliency:*** critical power support or mitigation during power outages;
- ***Reliability:*** improvement in power quality;
- ***Revenues:*** compensation to customers by grid operators or providers for services; and
- ***Avoided costs and/or revenues:*** financial incentives as defined by regulatory policies.

4.1 Government regulations and policies

Government regulations have a strong influence on DER adoption and its successful integration with the grid. More specifically, a state's regulations on renewable energy, electricity rates, environmental siting and permitting, and grid interconnection for DERs play a vital role in determining the financial attractiveness of DERs. In addition, enabling a robust market for DERs will benefit from the more efficient use of energy.

4.1.1 Policies and incentives

Policies and incentives are in place in Hawaii State to encourage the deployment of DERs. Chief among these renewable regulations are the RPS (discussed in Section 3.1), federal and state tax credits, as well as state-administered rebates. Requiring utilities to source renewable resources creates demand for DERs and makes an investment into DERs more attractive.[59]

Hawaii State also offers tax credits for DG technologies, which further incentivizes the uptake of DER.[60] This includes a state-level personal tax credit to residential customers, whereby they can claim 35% of the cost of equipment and installation for their solar thermal and PV systems.

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[56] NARUC. *Distributed Energy Resources Rate Design and Compensation.* November 2016.

[57] Black & Veatch and Smart Electric Power Alliance (SEPA). *Planning the Distributed Energy Future: Emerging Electric Utility Distribution Planning Practices for Distributed Energy Resources.* February 2016.

[58] DNV GL. *A Review of Distributed Energy Resources.* September 2014.

[59] National Renewable Energy Laboratory. *Strategic Sequencing for State Distributed PV Policies: A Quantitative Analysis of Policy Impacts and Interactions.* October 2012.

[60] Center for the New Energy Economy. *State Brief: Hawaii.*

Hawaii State offers a similar personal tax credit for residential customers with wind systems, where they can claim 20% of the cost of equipment and installation.[61]

On a federal level, the Solar Investment Tax Credit, extended in December 2015, allows residential customers to claim 30% of the installed cost through the end of 2019. For the average residential solar system costing around $30,000, this amounts to $9,000 in savings.[62] The credit is set to drop to 26% in 2020 and 22% in 2021, before dropping permanently to 0% for residential projects. This creates a sense of urgency among customers to install solar systems and is thus expected to increase deployment of solar PV installations across the US by 54% over baseline expectations without the extension.[63]

Combined, these regulations have allowed the State of Hawaii to achieve the highest solar electricity generation per capita from DG facilities in the US. By 2016, solar energy from both utility-scale and distributed resources generated 38% of the State's net generation from renewable resources.[64]

Hawaii State also administers rebates which encourage energy efficiency. These rebates include: the Solar Water Heater Rebate administered by Hawaii Energy, where customers of the HECO Companies receive either a direct upfront rebate of $1,000 or a $1,000 interest rate buydown;[65] the KIUC Solar Water Heating Rebate Program that administers the same $1,000 rebate to KIUC customers;[66] the Residential Energy Efficiency Rebate Program managed by Hawaii Energy, whereby residential customers receive rebate amounts ranging from $35-$200 for installing various energy efficient appliances.[67]

On EVs, Hawaii is at the forefront in providing incentives to EV owners. There are various incentives provided to EVs users. EVs are provided free parking in State and County lots and access to high occupancy vehicle lanes. The State also requires condominiums and apartment buildings to allow installation of EV charging stations and for large public parking lots to reserve

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[61] "Solar and Wind Energy Credit (Personal)." *DSIRE.* <http://programs.dsireusa.org/system/program/detail/50>

[62] Pomona Senior Theses. *Incentives for Distributed Generation in California: The Rise of Third-Party Solar Development.* 2013.

[63] "Impacts of Solar Investment Tax Credit Extension." *Solar Energy Industries Association.* <https://www.seia.org/research-resources/impacts-solar-investment-tax-credit-extension>

[64] "Hawaii: State Profile and Energy Estimates." *US Energy Information Administration.* <https://www.eia.gov/state/?sid=HI>

[65] "Solar Water Heater Rebate." *DSIRE.* <http://programs.dsireusa.org/system/program/detail/506>

[66] "KIUC – Solar Water Heating Rebate Program." *DSIRE.* <http://programs.dsireusa.org/system/program/detail/598>

[67] "Residential Energy Efficiency Rebate Program." *DSIRE.* <http://programs.dsireusa.org/system/program/detail/1368>

at least one space for an EV charging station. Furthermore, *HRS subsection 103D-412 (2009)* makes EVs the priority when state government agencies procure new light-duty vehicles.

Furthermore, the State has a revenue decoupling mechanism that mitigates the utility's financial incentive to increase volumetric sales. Under the traditional approach of rate-making, a utility recoups their fixed costs through fixed and volumetric charges. This rate design works when sales are increasing where the revenues are sufficient to recover the fixed costs and compensate the utility for cost increases due to the required system infrastructure upgrades or inflation and provide an adequate return on the utility's investments. However, if sales are sluggish or are decreasing due to conservation or energy efficiency programs, it will negatively impact the utility's finances. Revenue decoupling "de-links" the utility's revenues from the number of electricity sales to encourage the utility to pursue clean energy objectives.

4.1.2 Rate design

Another driver of the deployment of DERs is the rate design. Rates should not only provide the appropriate signals for investments but should also be able to compensate DER customers for the benefits that DER provides and properly charge them for the use of the grid. Well-thought-out rate design and compensation can allow customer and grid operator goals to be aligned, thereby spurring the deployment of DERs. For instance, rate designs that compensate (or charge) customers that produce benefits (or costs) for the grid may meet customer needs in a more cost-effective manner.

KIUC aims to develop new DER tariff options for its customers and to structure such new DER tariff options that are equitable to all its customers. KIUC submitted its DER proposal to the Commission on August 14, 2017, where it proposed two options to its customers when deciding whether to install solar PV at their homes and business. These two options are the customer self-supply and the smart export, which are described below. KIUC's President and Chief Executive Officer, David Bissell, said that "this proposed revised Schedule Q will allow us to accept more distributed energy resources onto the grid at the time of day when it is most needed."[68]

- **Customer Self-Supply ("CSS") -** allows a member/customer to install a solar PV or PV/battery system that meets some or all their own energy needs, but the member/customer agrees not to export any amount of energy more than the "Inadvertent Export" standard. In exercising this option, the member/customer will not receive utility compensation for any amount of energy export, including small amounts of energy export that may momentarily or inadvertently occur because of customer load and generation imbalances."

- **Smart Export** option - allows the member/customer the opportunity to operate as a "smart exporter" of energy. In other words, the member/customer exercising this option will only be compensated by KIUC for export at times whereby exported energy has value to the utility and, as such, will be compensated according to the value of the energy at the

[68] KIUC. *KIUC Files Proposal to Manage Distributed Energy Resources ("DER") with the PUC Additional Future Rate Changes Likely*. Page 1.

time of export. The solar PV system must include, among other things, a battery for energy storage, and the member/customer would have several options for the use of their self-generated energy: (a) export energy to the grid for and receive utility compensation during times of higher value to KIUC; (b) use energy to serve the member's/customer's own loads; (c) or store energy in the battery for later use."

The PUC has not yet approved this proposal due to their desire to see more discovery on KIUC's proposed Schedule Q methodology, which is different from the methodology that KIUC is currently using to calculate the monthly Schedule Q rate. The timing is uncertain at this point as KIUC is waiting for further instructions from the PUC that will govern the Market Track of the DER proposal, in which this proposal will be vetted further.

In New York, the value of DER Phase One tariff structures offer a glimpse into how future DER ratemaking initiatives may look. In March 2017, the NY Public Service Commission approved an order enacting a new compensation structure to more accurately and efficiently value distributed energy resources in New York State, transitioning away from NEM. One of the key changes to this new model is the transition from volumetric metering (tracking net kWh delivered to the grid) to monetary metering (converting energy production into dollars). Another change is that the project types have been better defined. For example, residential solar installations are categorized as mass market, while commercial customers with large projects are deemed either large-scale onsite or remote net metering, depending on their location. New York is among the five largest markets for DER and saw among the top ten growth rates for DER installations since 2011.

4.1.3 Interconnection and permitting process and requirements

Complex requirements regarding interconnection standards, siting and permitting requirements, and utility tariff agreements and eligibility criteria could potentially hinder DER adoption.[69] Indeed, in its Decision and Order No. 22248, the PUC required the electric utilities to establish a non-discriminatory interconnection policy that entitles distributed generation to interconnect to the island's electric system when it can be done safely, reliability and economically.[70] It also compelled utilities to develop a standardized interconnection agreement to streamline the DG application review process and eliminate long lead times that may lead to the cancellation of a beneficial project.[71]

In Hawaii State, information on the process to apply and interconnect for DG is readily available online. The Hawaii State Energy Office has a one-stop website with all the information needed

[69] Ibid.

[70] KIUC. *Distributed Generation Interconnection Policies and Procedures (For Distributed Generation Facilities No Larger than 20 MW) Tariff 2.* Original Sheet No. 3.

[71] Ibid.

about permits and requirements, called "Project Permitting Assistance and Resources."[72] There is also a program called "Renewable Energy Permitting Wizard"[73] which aids in determining the county, state, and federal permits that are needed for different projects. The wizard also creates a project-specific permit schedule which includes the required permits, step-by-step process, and timelines.

Interconnection requirements in the State are standard and similar to other markets. For instance, the requirements to install a rooftop solar PV system include submission of an interconnection request to the utility, engineering review, Certificate of Completion from the contractor, a final inspection from the utility, and building and electrical permits from the Department of Public Works (for Kauai) or the Department of Planning and Permitting ("DPP") (for the City and County of Honolulu).

Nevertheless, there are still some issues encountered by the applicants with regards to the permits and interconnection such as backlogs, inefficiency, and costs. For example, some utilities have been accused of being inefficient. In a Yale Environment 360 article, Erica Gies writes: "*Hawaii's solar boom ran into trouble in late 2013 when HECO began dragging its feet on approving new rooftop solar systems for connections to the grid, citing both technical and economic limitations.*"[74] There have been issues related to the elimination of the net metering program, which has complicated the integration of residential solar in the state's electricity mix. Under the CSS program, which allows homeowners to install residential solar PV systems so long as they do not export electricity back to the grid, customers have struggled to obtain battery permits from the Honolulu Department of Planning and Permitting to maintain their home systems. "*By last week, 420 residential rooftop solar systems attached to batteries were ready to be installed as soon as the battery systems are given the go-ahead. Unfortunately, the Honolulu DPP has given building permits to only 33, citing safety concerns.*"[75] Also, some residents in Oahu have complained about having to pay for upgrades to HECO's neighborhood electricity circuits to ensure the system can handle additional residential solar capacity. Gloria Adams, a resident of Mililani, stated: "*we didn't anticipate having to pay HECO when we took this [project] on.*"[76] However, it should be noted that the solar/storage industry developed very quickly in Hawaii and it is not surprising that there have been hiccups in permitting at state and utility level processes given this rapid change.

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[72] Hawaii State Energy Office. *Project Permitting Assistance and Resources.* Accessed on March 20, 2018. Available online at http://energy.hawaii.gov/developer-investor/project-permitting-assistance-and-resources.

[73] Hawaii State Energy Office. *Renewable Energy Permitting Wizard*. Accessed on March 20, 2018. Available online at http://wizard.hawaiicleanenergyinitiative.org/

[74] Gies, Erica. "Will New Obstacles Dim Hawaii's Solar Power Surge?" *Yale Environment 360.* February 16, 2015. <https://e360.yale.edu/features/will_new_obstacles_dim_hawaiis_solar_power_surge>

[75] Andorka, Frank. "Hawaii Strains to Permit Batteries as Self-Supply Permits Grow." *PV Magazine.* May 29, 2017. <https://pv-magazine-usa.com/2017/05/29/hawaii-strains-to-permit-batteries-as-self-supply-permits-grow/>

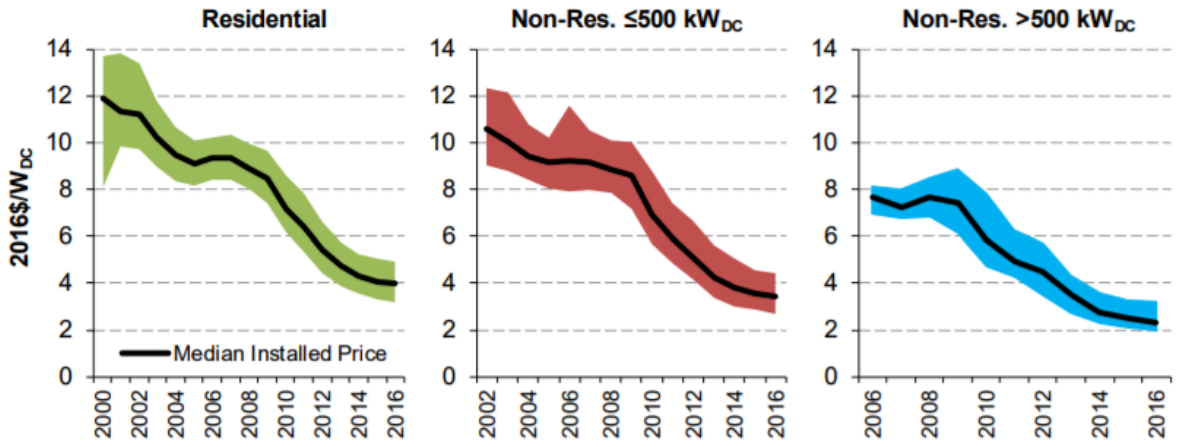
[76] Groom, Nichola. "Clouds over Hawaii's Rooftop Solar Growth Hint at U.S. Battle." *Scientific American.* <https://www.scientificamerican.com/article/analysis-clouds-over-hawaiis-roofto/>

4.2 Declining technology costs

With regards to changes in technology, both declining costs and technological advancements also serve as drivers of DER deployment. Costs are declining for DER technologies such as solar PV, storage solutions, and EVs, amongst others.[77]

In the US, installed prices of grid-connected solar PV systems have declined steadily, as seen in Figure 17 and Figure 18 below. Since 2000, roughly 53% of the total decline in the residential system installed prices can be attributed to falling module and inverter prices, while the remaining 47% is associated primarily with reductions in the aggregate set of soft costs. More recently, however, hardware costs have been the dominant driver for installed price declines. According to a US DOE report, the national median solar PV installed prices in 2016 declined year-over-year by $0.1/W (2%) for residential systems, $0.1/W (3%) for non-residential systems ≤500 kW, and $0.2/W (8%) for non-residential systems >500 kW.[78]

Figure 17. Installed solar PV price trends over time



Note: Solid lines represent median prices, while shaded areas show 20th to 80th percentile range.

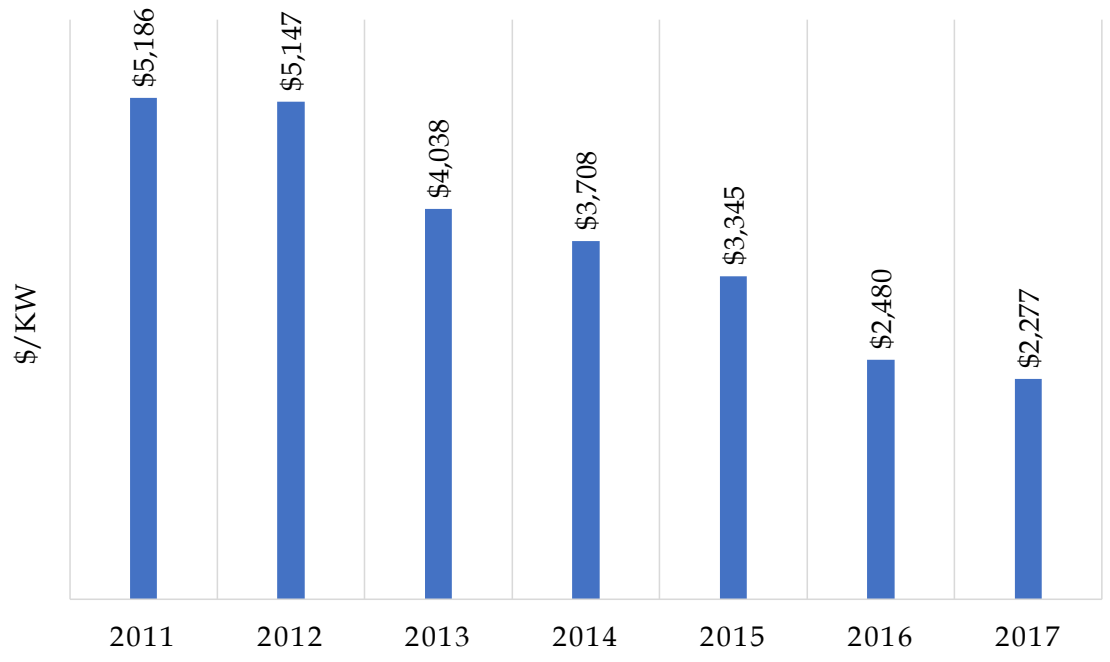
Source: Lawrence Berkeley National Laboratory and Sunshot US Department of Energy. Tracking the Sun.

Likewise, the decrease in solar capital costs is also documented in the Energy Information Administration's Annual Energy Outlook reports. From 2011 to 2016, solar PV capital costs decline by 9% per year on average as shown in Figure 18 below.

[77] Ibid.

[78] Lawrence Berkeley National Laboratory and Sunshot US Department of Energy. *Tracking the Sun 10.* September 2017.

Figure 18. Solar capital costs (2016$)



Source: Energy Information Administration. Annual Energy Outlooks for 2011 to 2017.

4.3 Technology advancement

DER technology performance has also been improving (e.g., increased efficiency of solar PV systems and increased battery energy density). These technological improvements not only provide benefits to consumers who utilize them, but to utilities as well. Examples of such technological improvements include:[79]

- smart inverters for solar PV systems and other DER technologies, supporting voltage and frequency stability for distribution systems;
- battery systems allowing demand to be met during demand spikes; and
- demand response programs (including EV charging loads) allowing for load reduction on a more granular basis.

In general, the technological advancements are reflective of not only the current levels of adoption of DERs but also of the anticipated increases in the future.[80]

[79] Ibid.

[80] NARUC. *Distributed Energy Resources Rate Design and Compensation.* November 2016.

5 Proposed changes to the ownership model and impact on DER

The change in the utility ownership models is not considered as a key driver of DER adoption and deployment. As discussed in the previous section, the key drivers for the DER deployment include government policies and incentives, technology costs, advancement in technology, and access to financing. Nevertheless, a change in the utility ownership model would have some influence on the DER policies in terms of the ease of access for DERs to the system and the fair treatment of these assets.

Among the four ownership models reviewed, holding everything else constant, the Project Team expects that the independent Single Buyer model would have the most positive impact on increasing the DERs in the state. Nevertheless, there are regulatory mechanisms that would align incentives under any model to achieve higher DER penetration and deployment.

We discuss the specific likely impact of each ownership model on the DER deployment in the following subsections.

Figure 19. Impact of change of ownership model to the DERs and the energy security and reliability

Change of the Ownership Model	Distributed generation	Energy storage	Demand response	Energy efficiency	Electric vehicles	Energy security and reliability
Move to IOU	—	—	↑	—	↑	—
Move to cooperative	↑	↑	↓	↑	—	—
Move to Single Buyer (within the utility)	↑	↑	—	—	—	—
Move to Single Buyer (outside of the utility)	↑	↑	—	—	—	—

5.1 Moving to an investor-owned model

If a utility changes from co-op to IOU ownership, the move would most likely have a positive impact on the demand response programs and electric vehicles programs for two main reasons: access to capital and expertise, and incentives to increase the utility's ratebase, off of which it earns a return. Because IOUs tend to have better access to additional resources namely staff and capital, it would be in a better position to implement DR programs. Moreover, it would also be able to build more electric vehicle charging stations and fund programs that will increase EVs. Furthermore, EV chargers will likely increase the capital expenditure of the utility and thus, will provide it with a higher rate base.

On the other hand, the impact of an IOU ownership model would be relatively neutral on the DG, energy storage, and energy efficiency programs. As discussed in Section 4.1, policies and incentives are already in place to encourage utilities to ensure non-discriminatory interconnection access of DGs to the system. The issue is more on the implementation of these policies and

programs. Energy efficiency programs would also not be negatively impacted under the IOU model since there is already revenue decoupling in place.

The change to IOU can further expand DER deployment *if* the incentives for the IOU management also increase. As mentioned in previous working papers, IOUs are generally motivated to increase shareholder value. If incentives to boost DERs helped enhance the return on investments for the shareholders, this would encourage the IOU to invest more in DERs.

Lastly, the ownership change would not impact the requirements to ensure system security and reliability. Therefore, a change to an IOU will not decrease system security or reliability as the utility still needs to comply with the regulations set by the PUC, as discussed in Section 3.3.

5.2 Moving to a cooperative model

A co-op ownership model may allow the utility to influence the procurement and deployment of DERs. As mentioned earlier, DERs such as energy efficiency and demand response programs help in reducing energy costs, thus favoring customers who are also members of the co-op. These members have a voice in the recommendations that the co-op's management puts forward to the Board, as co-ops are democratically controlled by their members. Furthermore, the Board of Directors of a co-op have the autonomy to set bold strategic goals (e.g., KIUC's goal of achieving 70% renewable by 2030).

Therefore, a change to a co-op model across the state could increase the utility's deployment of DGs, energy storage and the amount of EE. Under the co-op model, the Project Team anticipates that the DG-PV growth rate will be higher than the current projected growth rate (under PSIP) of 3.3% per year.[81] While this is the Project Team's anticipation, it is worth noting that KIUC has had lower penetration of DERs compared to the HECO Companies.[82] Whether a co-op would develop more DERs is also subject to its costs and benefits compared with grid-scale renewables, status of renewable integration in the system, and many other factors. The Project Team also anticipates that there could be more energy storage under the co-op model, holding everything else constant, because it could be easier for the co-op to forge partnerships with landowners, who are also members of the co-op. Moreover, it is projected that there could be more energy efficiency programs under a co-op model to help members-customers to participate in conserving energy and saving on their electric bills.

However, with regards to the DR programs, the impact is likely negative as resources such as staffing and capital are needed to ensure the implementation of the DR programs. For instance, HECO has the Fast DR program where they provide installation assistance to customers which include free preliminary audit and technical audit, and evaluation of the customer's facility

[81] It is not easy to determine quantitatively how much DG-PV will grow under a co-op model, but it should be noted that historically, KIUC's DG-PV growth rate was on average 19% per year from 2014 to 2017.

[82] As of 2017, KIUC had 22 MW of solar DG, while HECO, HELCO, and MECO had 479 MW, 103 MW, and 119 MW respectively. Source: HECO Companies. *PSIP Update Report*; KIUC website.

demand response opportunities.[83] Implementation of these programs requires additional manpower and resources. As discussed earlier, KIUC does not have any DR programs due to its limited resources and competing priorities. We assume that other co-ops would also likely have the same concerns as KIUC's.

Furthermore, under a co-op model, the utility would make decisions on DERs based on the policy priorities of the state or local government rather than from a shareholder return perspective. KIUC is a good example of how a co-op can serve to positively impact DER development.

Similar to the IOU, a co-op model will not have any negative impact on the system security and reliability since the utility is required to comply with the regulations set by the PUC.

5.3 Moving to a Single Buyer model (within the utility)

Under the SB model, the SB is presumed to be acting in the public interest. Although in this case the SB is inside the utility, it is independent of the utility and therefore would be assumed to be fair in its procurement process and would be in a position to better drive DER penetration. We anticipate that under the SB model, there could be an **increase in the deployment of DG and energy storage** because of the level treatment and access to the system that these technologies will receive under the SB model (within the utility).

However, there will be negligible or **no impact on energy efficiency, demand response, and EV** programs since the implementation of these programs will be done by the utility and not the SB. Finally, an SB model will not have any negative effects on the system security and reliability as the SB is responsible for ensuring that there is adequate supply to meet demand.

5.4 Moving to a Single Buyer model (outside the utility)

Similar to the Single Buyer within the utility, the independent SB (outside the utility) is assumed to be acting in the public interest. Since the SB that is outside of the utility will be more independent than the SB within the utility, it is expected that under this model, **DER deployment will grow moderately**. Therefore, it is anticipated that an independent SB model would have positive effects on DG and energy storage, similar to the co-op model.

Nevertheless, like the SB model within the utility, there will be **no impact on the energy efficiency, demand response, and EV programs** as these are under the purview of the utility, and not the SB. There will also be no negative impact on the system security and reliability under this model since it is SB's role is to ensure the security of supply to the electricity market.

[83] HECO Companies. *Demand Response*. Available online at https://www.hawaiianelectric.com/demand-response-faq. Accessed on March 29, 2018.

6 Appendix A: Scope of work to which this deliverable responds

Task 1.5.1 Estimated potential for each model to increase distributed energy resources, demand response programs, system security, reliability, resiliency, and RPS requirements through 2045.

CONTRACTOR shall estimate the potential for each model to increase distributed energy resources, demand response programs, system security, reliability, and resiliency, to meet Hawaii's RPS milestones through 2045. CONTRACTOR shall provide the logic and analysis that drives any incremental difference between ownership models.

DELIVERABLE FOR TASK 1.5.1 CONTRACTOR shall provide its conclusions and all work related to estimating the potential for each model to increase distributed energy resources, demand response programs, system security, reliability, resiliency, and to meet Hawaii's RPS milestones through 2045. CONTRACTOR shall provide an MS Word and/or MS Excel report, with supporting documentation, summarizing the assessment and including results of interviews with Hawaii stakeholders and other jurisdictions to determine how and why each ownership model helps, harms, or is neutral on these criteria. CONTRACTOR shall submit deliverable for TASK 1.5.1 to the STATE for approval.

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Load and number of customers forecast for the state of Hawaii

prepared for Department of Business, Economic Development and Tourism ("DBEDT") by London Economics International LLC

January 16, 2018

London Economics International ("LEI") was engaged by the Department of Business, Economic Development and Tourism ("DBEDT") to perform a load forecast from 2017 to 2045 for the state of Hawaii, as part of the resource planning process of the engagement. Load forecasting is a critical part of a rate-setting exercise to estimate likely peak demand and energy consumption based on different scenarios. LEI reviewed the load and customer forecast covered in the Power Supply Improvement Plans December 2016 ("PSIP") for the counties served by the Hawaiian Electric Companies ("HECO Companies") and performed independent load and customer forecasts for the county of Kauai. This memo discusses LEI's approach, data sources, and results of the forecasts. In addition, this memo is accompanied by an excel file called "Load Forecast for the State of Hawaii," which provides the detailed assumptions and results by year.

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List of acronyms

CAGR	Compound Annual Growth Rate
DBEDT	Hawaii Department of Business, Economic Development, and Tourism
DG-PV	Distributed Generation – Photovoltaic
E3	Energy and Environmental Economics, Inc.
EE	Energy Efficiency
EV	Electric Vehicle
GWh	Gigawatt-hour
HECO	Hawaiian Electric Company
HELCO	Hawaii Electric Light Company
KIUC	Kauai Island Utility Cooperative
LDV	Light-duty electric vehicle s
LEI	London Economics International, LLC
MECO	Maui Electric Company
NEM	Net Energy Metering
PSIP	Power Supply Improvement Plans December 2016
UHERO	University of Hawaii Economic Research Organization

1 Executive Summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which responds to Task 1.5.2 in the project scope of work, provides a projection of potential electrical load in Hawaii to be served from 2017 to 2045.

Electricity load forecasts are important to plan investments in new generating capacity as well as in building transmission and distribution lines. It is also vital in evaluating the reliability of electricity supply.

For the counties served by the HECO Companies, LEI used the projections from the companies' Power Supply Improvement Plans – December 2016 ("PSIP") since the methodologies used are in line with the industry standards. For the county of Kauai, LEI performed an economic analysis to forecast the load in the county.

Based on the PSIP and LEI's analysis, the gross peak load for the State of Hawaii is expected to grow from 1,933 MW in 2017 to 2,447 MW in 2045 with a compound annual growth rate ("CAGR") of 0.85% per year. Oahu accounts for more than 70% of the total gross peak load, followed by Maui (13%), Hawaii (12%), and Kauai (4%). Likewise, the gross energy demand for the state is projected to grow from 11,652 GWh in 2017 to 14,806 GWh in 2045 with a CAGR of 0.86% per year.

With the influx of energy efficiency programs, distributed generation – photovoltaic ("DG-PV"), energy storage, and energy vehicles ("EV"), the net peak load and net energy consumption are projected to be lower than the gross peak load and energy consumption. The net peak load declines slightly from 1,665 MW in 2017 to 1,640 MW in 2045 while the net energy consumption is anticipated to increase only slightly from 9,121 GWh in 2017 to 9,239 GWh in 2045.

Furthermore, LEI also estimates that the projected number of customers will grow at a stable average rate of 0.6% per year from 499,063 customers in 2017 to 586,377 customers in 2045. The City & County of Honolulu accounts for more than 60% of the customers, followed by 18% from Hawaii County, 14% from Maui County, and the remaining 7% from Kauai County. Industrial users are projected to continue to be the largest customers at 40% followed by the commercial (>30%) and residential (>25%) sectors.

Gross peak load – is the maximum load during a specified period of time without considering the energy efficiency ("EE") programs, distributed generation – photovoltaic ("DG-PV"), and energy vehicles ("EV").

Net peak load – is peak load during a specified period of time net of EE, DG-PV, and EV.

Gross energy consumption – required energy as an input to provide products and/or services without taking into account the EE, DG-PV, and EV.

Net energy consumption – is energy consumption net of EE, distributed DG-PV, and EV.

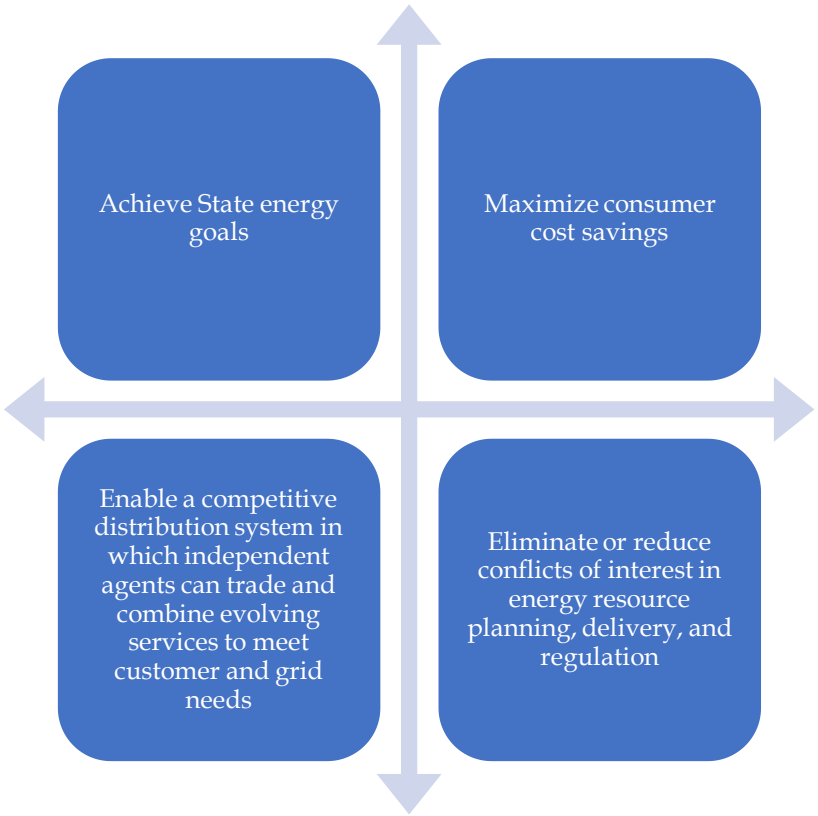
2 Introduction and scope

2.1 Project description

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission on a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[1] was contracted to perform this study.[2]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[3] listed in Figure 1.

Figure 1. State's key criteria in evaluating the models



Source: Scope of Services under Contract No. 65595

[1] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[2] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[3] House Bill No. 1700 Relating to the State Budget.

The study will help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[4]

2.2 Role of this deliverable relative to others in the project

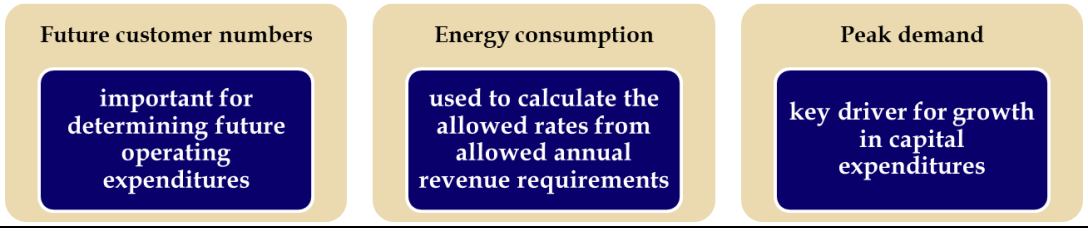
This deliverable corresponds to Task 1.5.2. in the project scope of work. It provides a projection of the potential electrical load and numbers of customers to be served through 2045. The load forecasts in this deliverable will be used in the revenue requirements model (Task 1.6.3. for the ownership models and Task 2.5.1 for the regulatory models) to calculate the average electricity rates, which is another deliverable under Task 1.6.4. (ownership models) and Task 2.5.2. (regulatory models).

[4] Hawaii Contract No. 65595. Scope of Services.

3 Overview of load forecasting

Load forecasting is important to utilities because it takes several years to plan, secure approval, and build new generating units. Load forecasting is also a critical part of rate-setting as it projects the number of customers, energy consumption, and peak demand which helps to determine the future operating expenditure, capital expenditure, and the allowed rates from the annual revenue requirements.

Figure 2. Importance of energy load and consumption, and number of customer forecast



The accuracy of forecasting is critical to the planning process of a utility. Over-/under-forecasting the load will result in over-/under-estimating the spending and investment in the planning process, and higher/lower rates than needed. Ultimately, over forecasting will lead to an over-build of generation and distribution infrastructure which will likely increase rates for customers. On the other hand, under-forecasting will mean fewer investments in infrastructure which may lead to reliability concerns and more system congestion. Figure 3 illustrates the consequence of over-/under-forecasting the load.

Figure 3. Consequence of over and under forecasting the load

Area	Over-forecasting	Under-forecasting
Financial forecasting	• Likelihood of stranded assets	• Likelihood of disruptions in electric service
Generation planning	• Investing in more generation capacity than necessary • Reliability ensured but at high costs	• Not investing in sufficient generation capacity • Lower expenses are more than offset by economic costs of worsening reliability
Transmission planning	• Excessive investments in transmission lines or capacity • Reliability ensured but at high costs	• Investing in fewer or lower capacity transmission lines • Worsening reliability and congestion
Distribution planning	• Excessive buildout of distribution infrastructure • High costs to ensure reliability	• Not building sufficient distribution infrastructure • Worse reliability
Cost of service allocation	• Customer segments for whom load is over-forecasted incorrectly get allocated higher costs	• Customer segments for whom load is under-forecasted get cross-subsidized
Rate design	• Over-forecasting electric sales results in rates that may not be sufficient to cover costs	• Under-forecasting electric sales results in rates that may be set too high

3.1 Components of the load forecast

Future load and energy forecasts are impacted by assumptions and expectations of weather, macroeconomic and demographic factors, and the adoption of energy efficiency ("EE"), demand

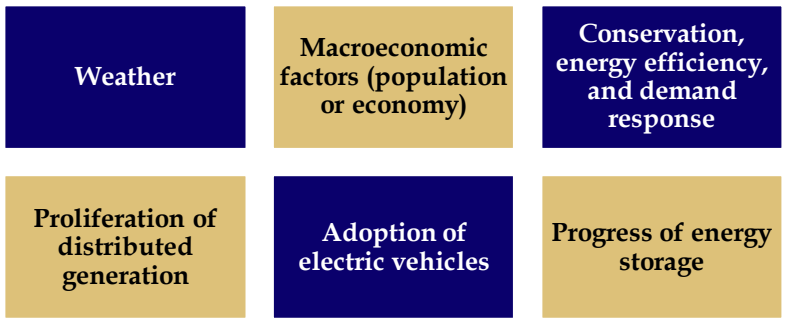
response ("DR"), distributed generation ("DG"), electric vehicle ("EV"), and energy storage. Changes in any of these variables will impact the forecasts. The extent to which and how customer behavior will change adds to the difficulty of forecasting load and energy consumption, particularly with technologies that are evolving quickly.

Weather is a key driver for load shape and peak load. The peak demand for electric power in Hawaii is heavily influenced by hot and humid weather. As the temperature and humidity rise, the demand for cooling (i.e., air-conditioning) rises. When forecasting the load, a weather-normalized load is often used. A weather-normalized load utilizes a standard weather condition based on the average of seasonal extremes during the historical period to forecast load.

Macroeconomic factors include population growth, economic growth, and employment rate, which are often positively correlated with the load. For example, higher population growth or economic development often indicates a higher load growth. Demographic forecasts are essential to the development of long-range forecasts as consumption of electricity is closely correlated with demographic statistics. Economic development generally includes variables such as gross state product, employment, and real personal income. Most of these variables used are specific to the jurisdiction.

EE and DG often contribute to reducing demand, resulting in a lower net load requirement for the system. EVs and other similar forms of beneficial electrification generate incremental new demand for electricity. Customers with behind-the-meter energy storage could use grid electricity or DG to charge the storage device, which could cause either a net increase or a net decrease in load.

Figure 4. Components in the load forecast



3.2 Load forecast methodologies and approaches

There are two commonly used load forecasting methodologies often utilized by planners. These are the top-down approach and the bottom-up approach.

Under a top-down approach, the analysts look at the different variables that impact the load and energy forecasts such as weather, macroeconomic indicators, etc. The forecasting team develops models for each revenue class as well as scenarios through the forecasting horizon. After the top-level load forecasts are developed and approved by the senior management team, they are then shared with the organization for their planning and budgeting activities. Top-down forecasting

includes a trend analysis which relies solely on historical load with no consideration of the factors that affected the amount of energy used and an econometric analysis which attempts to quantify the relationship between input and output. The advantages of this approach include efficiency and consistency. Redundancy and duplication is minimized in the process under the top-down approach.

Bottom-up forecasting begins by aggregating the local load forecasts. Then, the forecasting team converts the bottom-up load forecasts to revenue level forecasts. Bottom-up forecasting also includes two methods. One is a survey-based forecast using information from a select group of customers regarding their forecast. The other is an end-use model which examines energy use at the individual level. An advantage of the bottom-up approach is that insight about customers and load are seamlessly integrated into the local load forecasts. A disadvantage of this approach is that it may be challenging to ensure that local load forecasts across different regions are being developed with a uniform approach; incorporating insights about customer and load trends in only some regions may disrupt the broader forecast.

One of the key differences between these two approaches is that the top-down forecast aggregates the historical data first, while the bottom-up forecast approach aggregates the forecast. Figure 5 shows the process of each approach.

Figure 5. Two popular load forecasting methodologies

	Top-down Load Forecasting	Bottom-up Load Forecasting
Typical Process	• Develop weather indices • Develop macro economic indices • Develop model(s) for each revenue class • Develop scenarios • Develop scenario based load forecasts for each revenue class	• Conduct a local planning study to come up with local load forecast • Aggregate/roll up to corporate level • Converts the bottom-up load forecasts to revenue class forecasts

There are three methodological **approaches** typically performed in the load forecast:

1. econometric method,
2. energy utilization method, and
3. trending analysis.

Econometric modeling is a key quantitative method used when developing load and energy forecasts. Econometric modeling relies on models to forecast a variable based on historical trends or causal relationships with other factors and typically takes one of two forms – time series models and causal/associative models. It estimates the relationship between electricity consumption and the key variables that affect consumption (such as economic growth, population, price, etc.). The advantage of this approach is that it requires a relatively small amount of data. In addition, the modeling can be continuously updated as the projections of the key variables change. The disadvantage of this approach is the assumptions on the past relationships may not be the same in the future.

Trending assumes historical consumption continues to grow going forward. It analyzes historical data to develop the best fit curve to represent the historical growth trend and applies it to project future growth trend. Trending is limited by manual adjustment to modify the curve in anticipation of certain significant changes in demand or key drivers different from historical trends. The advantage of trend analysis is that it is easy to understand. The disadvantage of this approach is that results could be inaccurate when there are sudden substantial changes in the variables that impact the electricity consumption.

Energy utilization ("EU") (also known as end-user) method derives forecast electricity consumption based on forecast customer numbers, disaggregated by customer type. It assumes average annual consumption per customer type does not change. The consumption of the large customers usually is forecasted individually and overlaid on the underlying EU estimate. The EU method is limited by situations where the per customer consumption is changing significantly. This has not happened historically but in a context of grid defection and a proliferation of EVs and storage, this could happen.

3.3 Forecast variability

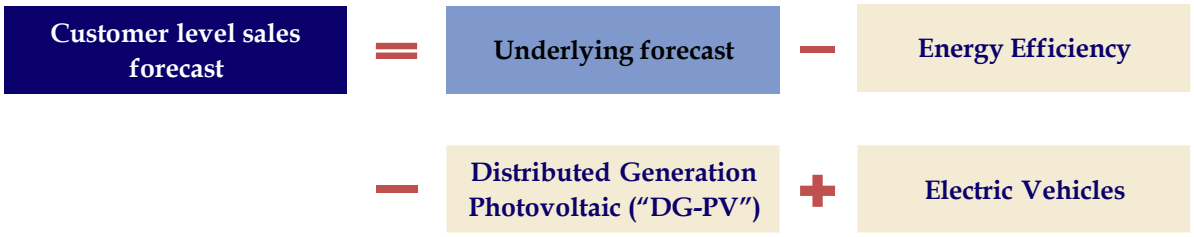
Load and energy consumption forecasts depend on other forecasts of key variables as mentioned earlier. Changes in these variables will impact the forecasts. Other forecast uncertainties include potential increases in load due to new customers and potential losses in load due to changes in customers' behavior or operations.

4 Load forecasts for the counties served by the HECO Companies

The counties served by the HECO Companies, namely Hawaii, Maui, and Oahu, have publicly available load forecasts in the PSIP. The HECO Companies applied the top-down and bottom-up approaches to forecasting the load of these counties and utilizes the econometric modeling. The methodology for deriving net peak load and energy requirements to be served by Hawaiian Electric ("HECO"), Maui Electric ("MECO"), and Hawaii Electric Light ("HELCO") begins with the identification of key factors that affect load growth. These factors included the economic outlook, analysis of existing and proposed large customer loads, and impacts of customer-sited technologies such as EE measures and DG.

In addition, the HECO Companies evaluated impacts from emerging technologies such as EV and energy storage given their significant potential impact on future demand for energy. The PSIP documents the customer level sales forecast based on the formula shown in Figure 6. Each component of the formula will be discussed in the succeeding subsections.

Figure 6. Customer level sales formula



Source: PSIP Update Report: December 2016. J-21.

4.1 Load forecast methodology

The HECO Companies utilized an econometric analysis to derive the underlying forecast by incorporating projections for key drivers of the economy prepared by the University of Hawaii Economic Research Organization ("UHERO") in April 2015.[5] According to the PSIP, economic growth is "typically the most influential factor when forecasting long-term changes in sales and peak demand."[6] Three key economic indicators were used to perform the econometric analysis: (i) real personal income per capita, (ii) non-farm jobs, and (iii) visitor arrivals. The HECO Companies also considered electricity price and weather variables in the econometric model.[7]

The HECO Companies uses both the bottom-up and top-down approaches in its load forecast. Bottom-up forecasting is used in projecting system-wide loads as well as loads of specific customer classes (like residential or commercial) while top-down forecasting is used to develop

[5] PSIP Update Report: December 2016. J-24.

[6] PSIP Update Report: December 2016. J-20.

[7] Ibid.

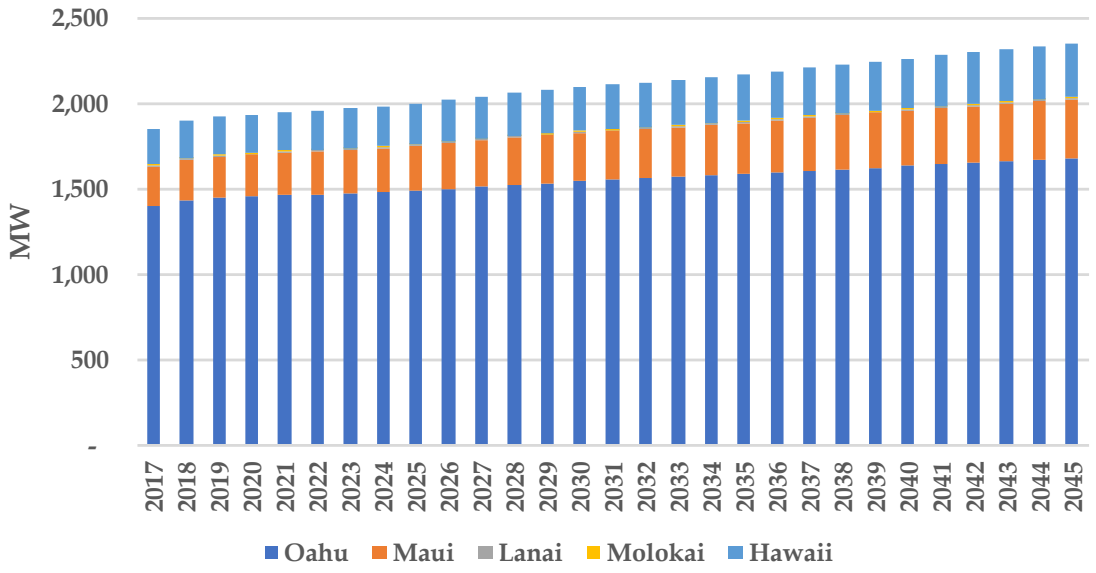
aggregate control area loads.[8] The HECO Companies' methodology in forecasting load and energy are in line with the industry standards and similar to some of the process discussed in the earlier section.

4.2 Underlying load and energy forecasts

The PSIP shows that Oahu accounts for more than 70% of the gross load, followed by 14% from Maui, and 12% from Hawaii. Lanai and Molokai account for about 0.3% each. The gross peak load growth ranges between 0.06%and 1.43% annually with Maui having the highest average growth rate among the islands. The total gross peak load growth for the five islands averages 0.86% per year. Figure 7 shows HECO Companies' projected **gross peak load** by each island from 2017 to 2045.

Gross peak load represents the maximum peak in a given period before adjustment for EE, DG-PV, and EV

Figure 7. Projected gross peak load by island from PSIP



Source: PSIP. Update Report December 2016. J-50 – J-54.

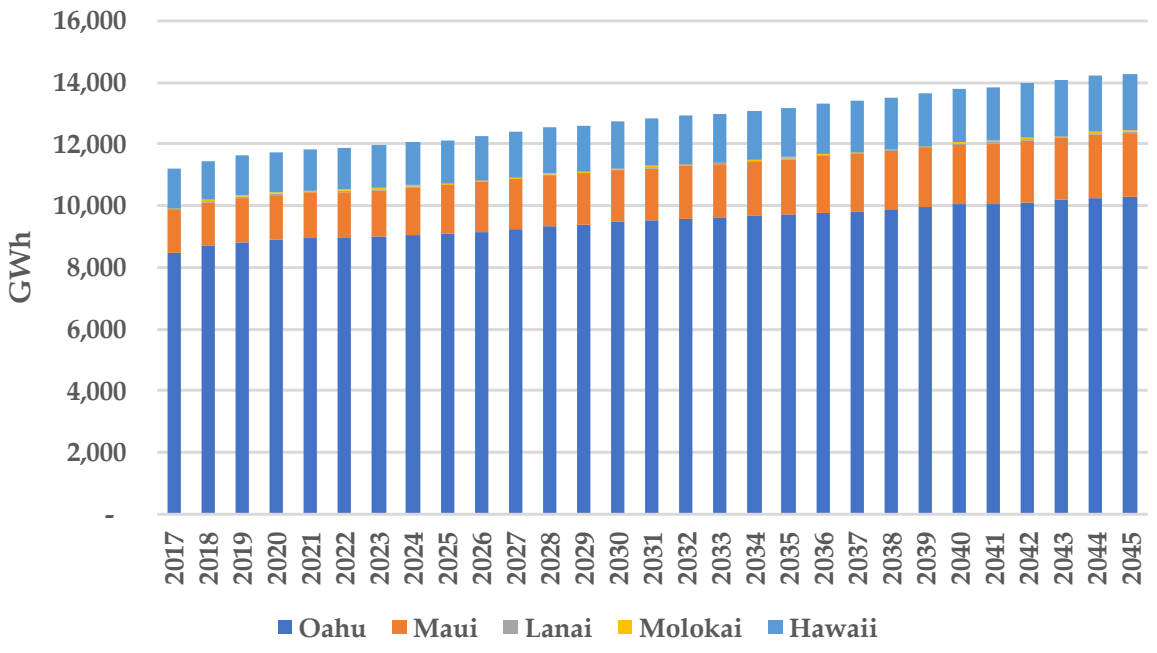
Similar to the gross peak load, Oahu accounts for more than 70% of the gross energy consumption among the five islands served. This is followed by 14% from Maui and 12%from Hawaii. Lanai and Molokai account for about 0.3% each. The gross energy consumption growth ranges from 0.08% (Molokai) to 1.44% (Maui) annually for different islands. The total gross energy consumption

Gross energy consumption represents energy consumption before adjustment for EE, DG-PV, and EV

[8] PSIP Update Report: December 2016. Page A-21.

growth for the five islands averages at 0.87% per year. Figure 8 illustrates the projected **gross energy consumption** by each island.

Figure 8. Projected gross energy consumption by island



Source: PSIP. Update Report December 2016. J-45 – J-49.

4.3 Assumptions on energy efficiency

The HECO Companies assumed that the preliminary projections for impacts associated with EE measures over the next 5 to 10 years were consistent with historical average annual impacts achieved by the Public Benefits Fund Administrator, Hawaii Energy.[9] Also, the HECO Companies incorporated the impacts from Hawaii Energy's EE programs and changes to building and manufacturing codes and standards.[10] Collectively, the HECO Companies

Energy efficiency programs are designed to encourage the reduction of energy used by end-use devices and systems. Savings are generally achieved by substituting more technologically advanced equipment to produce the same level of energy services (for example, lighting, water heating, motor drive) with less electricity.

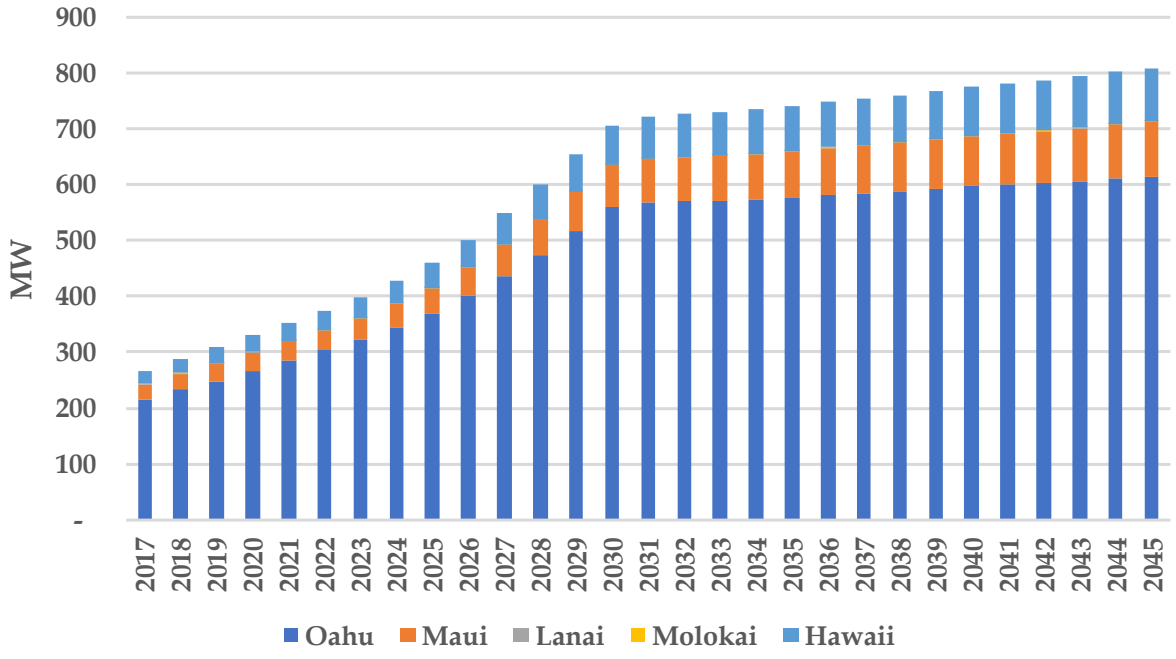
[9] Ibid.

[10] PSIP Update Report: December 2016. page J-24.

projected that these changes would enable Hawaii to meet its long-term energy efficiency goal in 2030.[11]

Figure 9 shows HECO Companies' projected cumulative **EE** by each island. From 2017 to 2030, there is a sharp increase of EE installation, by an average of 6.5% compound annual growth rate ("CAGR") across the five islands. From 2031 and onwards, the development of EE remains at a flatter rate of 0.8% per year.

Figure 9. Projected cumulative EE installation by island

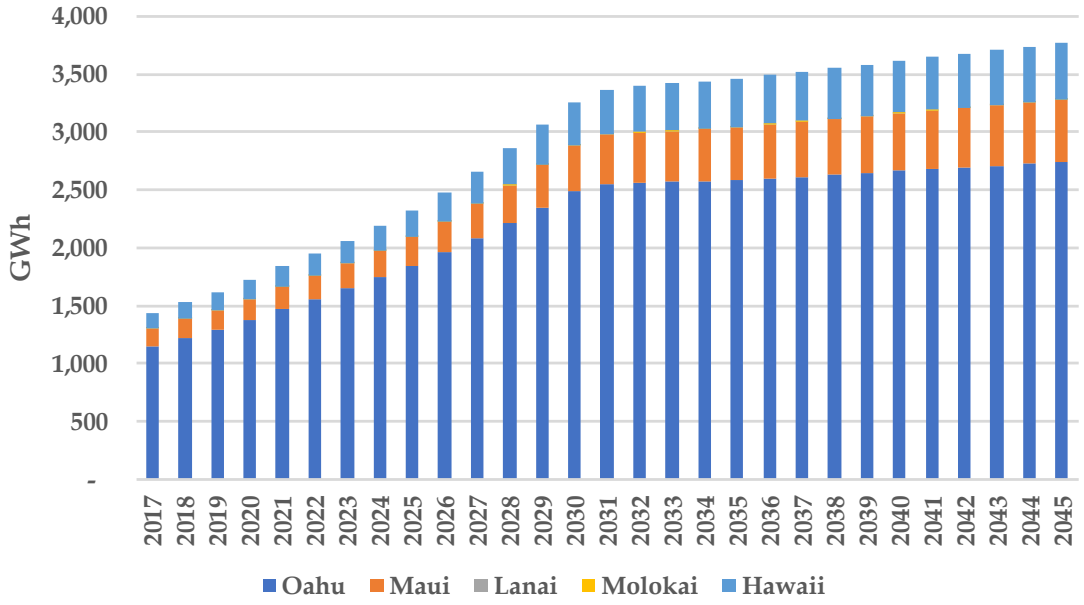


Source: PSIP. Update Report December 2016. J-50 – J-54.

Figure 10 illustrates HECO Companies' projected **reduced energy generation from EE** for each island. Similar to the EE, from 2017 to 2031, there is a sharp increase in reduced generation from EE, by an average of 7.8% CAGR across five islands. From 2031 onwards, the reduced energy consumption from EE remains at a flatter rate of 0.8% average per year.

[11] PSIP Update Report: December 2016, pages J-45 – J-54.

Figure 10. Projected reduced energy generation from EE by island



Source: PSIP. Update Report December 2016. J-45 – J-49.

4.4 Assumptions of DG-PV

According to the HECO Companies, customer economics is the primary driver for the adoption of DG-PV in Hawaii. Customer economics are driven by two factors namely the benefits of the DG-PV system (i.e., savings from electricity purchases from the utility and payments received selling to the grid) to the customer and the capital and operating costs of the DG-PV system.[12]

Distributed generation photovoltaics ("DG-PV") is the most significant form of distributed energy resource. These are the solar PV generation installed at the homes and businesses

Source: PSIP, H-4

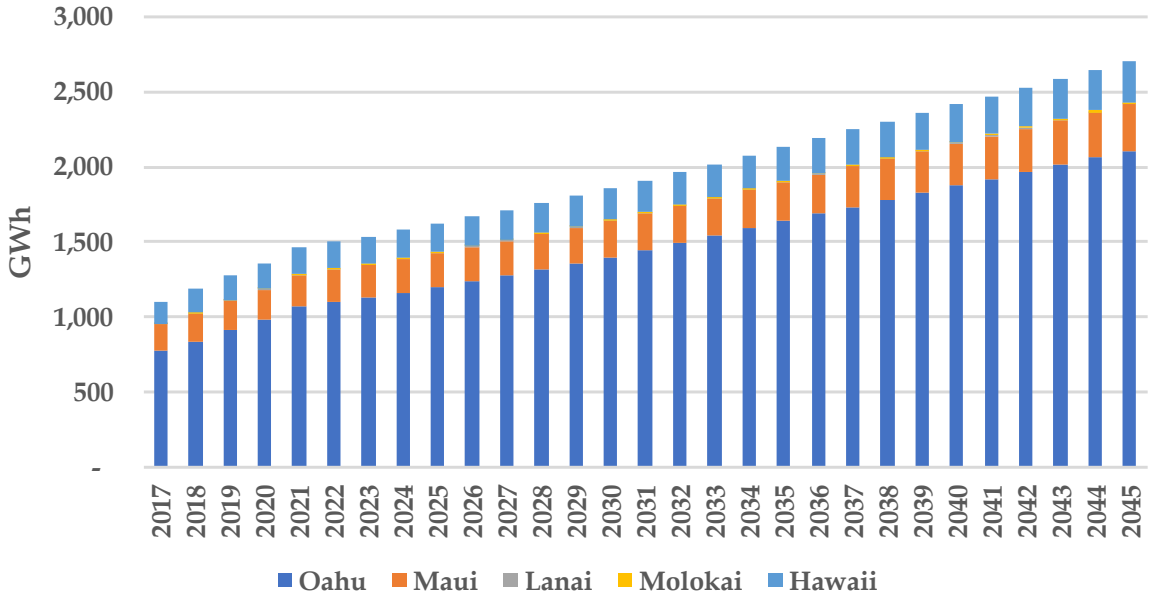
The HECO Companies' projected **DG-PV** using a bottom-up analysis by aggregating each company's tariffed programs developed separately for residential and commercial customers, including legacy Net Energy Metering ("NEM"), Standard Interconnection Agreement, grid-supply to the cap, self-supply, and potential future grid-supply.[13] A customer adoption model developed by the Boston Consulting Group to determine the self-supply paired with distributed energy storage systems to optimize customer economics was also applied to the analysis.

[12] PSIP Update Report: December 2016. page H-4.

[13] PSIP Update Report: December 2016. page J-25.

Figure 11 shows the projected generation from DG-PV by island growing at an average stable rate of 3.3% CAGR from 2017 to 2045 for the five islands.

Figure 11. Projected generation from DG-PV by island from PSIP



Source: PSIP. Update Report December 2016. J-45 – J-49.

4.5 Assumption of electric vehicles

The key drivers of the adoption of electric vehicles include incentives for the purchase of EVs and expansion of the charging stations. The HECO Companies' projected **EV energy consumption is** based on an estimate of the number of EVs purchased per year using a historical average annual growth rate then multiplying by an estimate of the annual energy used per vehicle.[14]

An **electric vehicle** is a vehicle that uses one or more electric motors or traction motors for propulsion

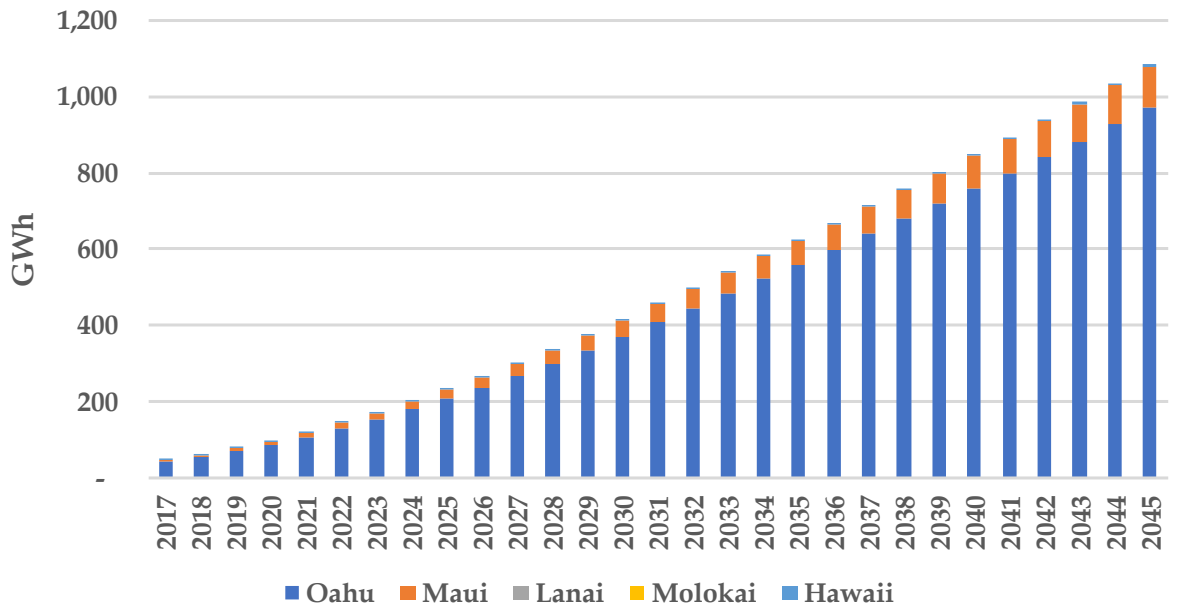
Source: PSIP, A-11

Oahu is the largest contributor to EVs, accounting for nearly 90% of the energy consumption, followed by 10% from Maui (Figure 12). EV energy consumption from Hawaii is projected to be minimal, accounting for only 0.5% of the total forecasted EV energy consumption. Energy consumption from EVs was not estimated for Lanai and Molokai. The development of EVs grows at a faster pace than EE and DG, at an average CAGR of 12% from 2017 to 2045 for five islands.[15]

[14] PSIP Update Report: December 2016, page J-34.

[15] According to the Electrification of Transportation Strategic Roadmap, HECO Companies retained Energy and Environmental Economics, Inc. ("E3") to perform an economic analysis of electrification of transportation using light-duty vehicle ("LDV") electrification on Oahu as an initial case study and focusing on the 2018-

Figure 12. Projected energy consumption from EV by island from PSIP



Source: PSIP. Update Report December 2016. J-45 – J-49.

4.6 Net peak demand and energy consumption forecast

Net peak demand and net energy consumption forecasts are calculated by deducting EE and DG-PV and adding EV to the gross energy consumption. Figure 13 shows an example of the net energy consumption calculation for 2017.

HECO Companies projected a net peak load for the five islands to reach a peak at 1,614 MW in 2019 and gradually decline to 1,393 MW in 2031, at a CAGR of -1.2% (Figure 14). From 2031 onwards, the net peak load is expected to grow at a flatter rate of 0.8% annually. The net peak load trend is consistent with the trend in the proliferation of EE from 2017 to 2031 and a flatter growth afterward.

Net peak load represents peak load after adjustment for EE, DG-PV, and EV

2045 period. According to E3's forecast, by 2045, 55% of personal LDVs in Oahu are projected to be fully electric. E3 estimated that the electricity sales associated to this adoption rises from 20 GWh in 2018 to 1,200 GWh in 2045. (See HECO Companies. *Electrification of Transportation Strategic Roadmap*. March 2018. pp. 33-34, 145).

Figure 13. Illustration of how the net energy sales is calculated for 2017 for the state (GWh)

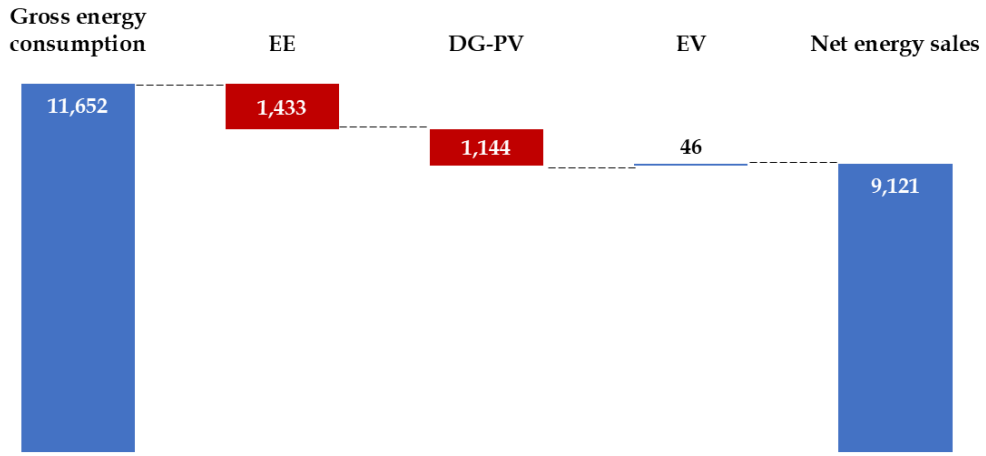
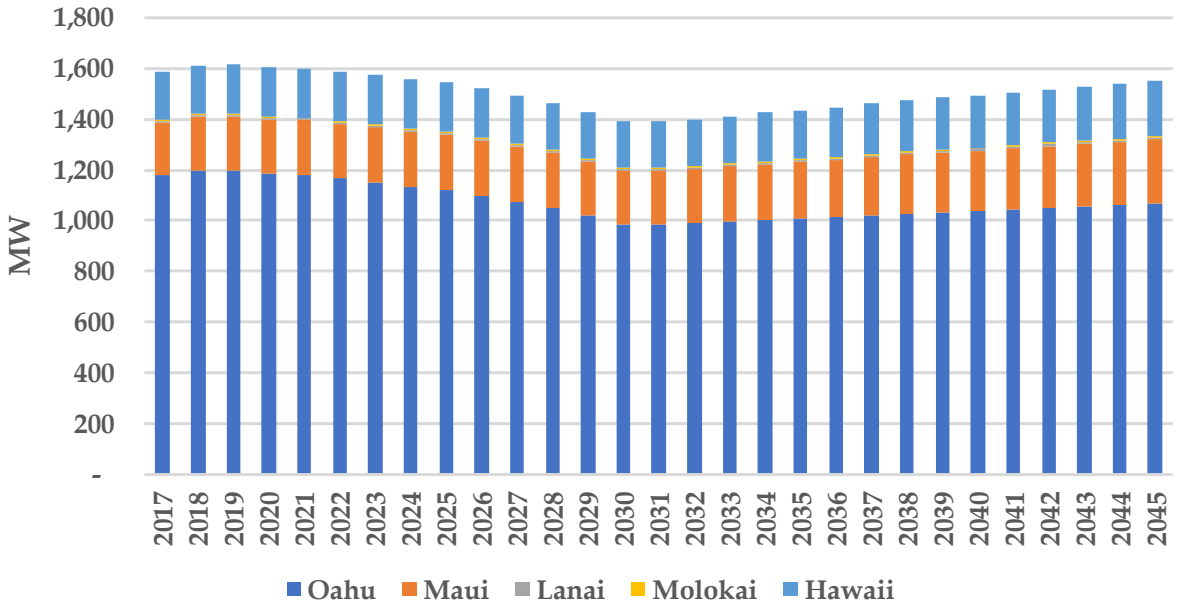


Figure 14. Projected net peak load by island from PSIP

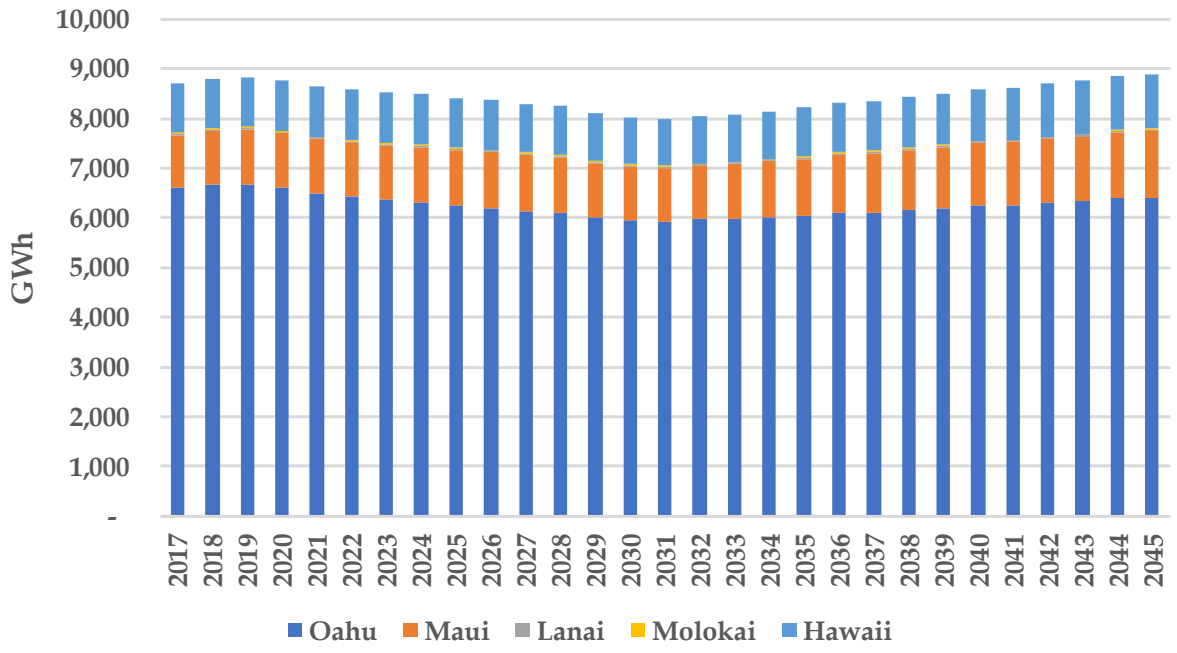


Source: PSIP. Update Report December 2016. J-50 – J-54.

HECO Companies expect that the net energy consumption will grow at a similar pattern as the net peak load does. As shown in **Error! Not a valid bookmark self-reference.**, the net energy consumption is projected to reach 8,827 GWh peak in 2019, and gradually decrease to 8,004 GWh, at a CAGR of -0.8%.[16] From 2031 onwards, the net peak load is expected to grow at a CAGR of 0.8% annually.

Net energy consumption represents energy consumption after adjustment for EE, DG-PV, and EV

Figure 15. Projected net energy consumption by island from PSIP



Source: PSIP. Update Report December 2016. J-45 – J-49.

[16] PSIP Update Report: December 2016, pages J-45 – J-49.

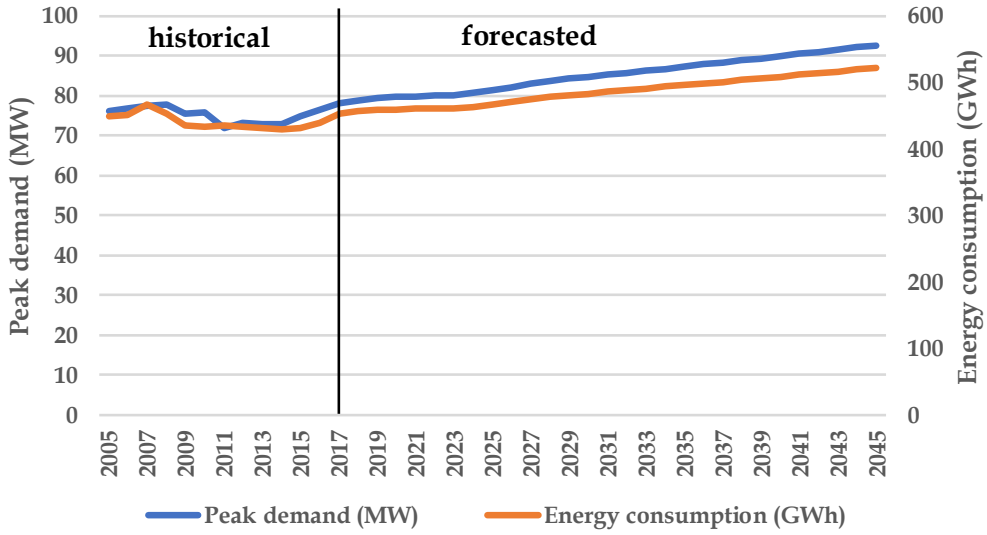
5 Load forecast for the Kauai County

KIUC does not have any publicly available load forecasts for the county of Kauai.[17] To forecast the load, LEI applied a similar process of forecasting the load consistent with the PSIP's methodology discussed in Section 4.1.

5.1 Underlying gross peak load and energy forecasts

LEI performed an econometric analysis to forecast load by analyzing the relationship between the historical data of peak load and energy consumption in Kauai, and the key drivers of the economy reported by UHERO. As shown in Figure 16 below, the econometric model indicated a strong correlation between gross peak load/energy consumption and economic indicators such as real personal income per capita, non-farm jobs, and visitor arrivals. Specifically, the relationship between gross peak load and economic indicators are significant at 1% significance level and has a good fit at an R-square of 0.81. The relationship between gross energy consumption and economic indicators are significant at 5% significance level and has a relatively good fit at an R-square of 0.58.[18]

Figure 16. Historical and projected gross peak load and energy consumption for Kauai



Source: Kauai Island Utility Cooperative Annual Reports to PUC; UHERO; LEI analysis

[17] LEI was informed by KIUC that it does not have a publicly available information on the load forecasts for the Kauai county in an email dated December 1, 2017.

[18] In statistics, a 5% significance level means that there is 5% probability that the relationship is not significant. In general, a significance level of 5% or lower indicates that the relationship is significant. R-squared is a statistical measure of how close the data are to the fitted regression line. In general, the higher the R-squared, the better the fit.

Figure 16 shows the historical and projected gross load and energy consumption for Kauai. Based on our analysis, gross peak load is expected to grow from 78 MW in 2017 to 93 MW in 2045 at a CAGR of 0.6%. Gross energy consumption is expected to grow from 454 GWh to 522 GWh at a CAGR of 0.5%.

5.2 Assumptions for EE and DG-PV

As of 2016, there are 369 kW of commercial EE in Kauai.[19] However, Kauai Island Utility Cooperative ("KIUC") plans to install 212 kW commercial EE installation in 2017, which is projected to have a generation impact of 1,289 MWh.[20] LEI forecasted EE to grow at 15% CAGR from 2017 to 2030 and to grow at 2% CAGR from 2031 to 2045 (Figure 17). 15% CAGR from 2017 to 2030 is derived from the historical annualized growth of generation impact from EE.[21] 2% CAGR from 2031 to 2045 is projected at the higher end of the overall trend of EE development from the other counties.[22] LEI projected a higher than average penetration rate for EE in Kauai to comply with Hawaii's long-term EE goal in 2030.[23] The PSIP projected a faster pace of EE penetration from 2017 to 2030 and a continuous stable growth post-2030 to achieve the 30% sales reduction goal stated in the Energy Efficiency Portfolio Standards in the State of Hawaii.[24]

As of 2016, there is more than 25 MW of DG-PV installations in Kauai, or more than 40 GWh of generation from DG-PV through various programs in Kauai, accounting for 33% of Kauai's gross peak load, and 9% of the gross generation in Kauai.[25] LEI projects DG-PV to grow at a CAGR of 5% from 2017 to 2045, reaching 28% of the gross generation in Kauai (Figure 18). LEI projects DG-PV in Kauai to grow at a higher rate than the growth in other counties (at an average of 3.3% CAGR from 2017 to 2045), given that growth of DG-PV installation has been higher in the other counties than in Kauai from 2012 to 2016.[26] Installed DG-PV capacity per capita grew from 0.12

[19] Docket No. 05-0075 - In re Public Utilities Commission's Investigation of Kauai Island Utility Cooperative's Proposed Revised Integrated Resource Plan and Demand Side Management Framework: 2016 Annual Modification and Evaluation Report ("AMER") and Energy Services Program Report. December 22, 2016. p.11.

[20] Ibid.

[21] Ibid.

[22] From 2031 to 2045, Oahu EE is projected to grow at 0.5% CAGR. Maui and Hawaii are projected to grow at 1.7% CAGR.

[23] PSIP. Update Report December 2016. Page J-24.

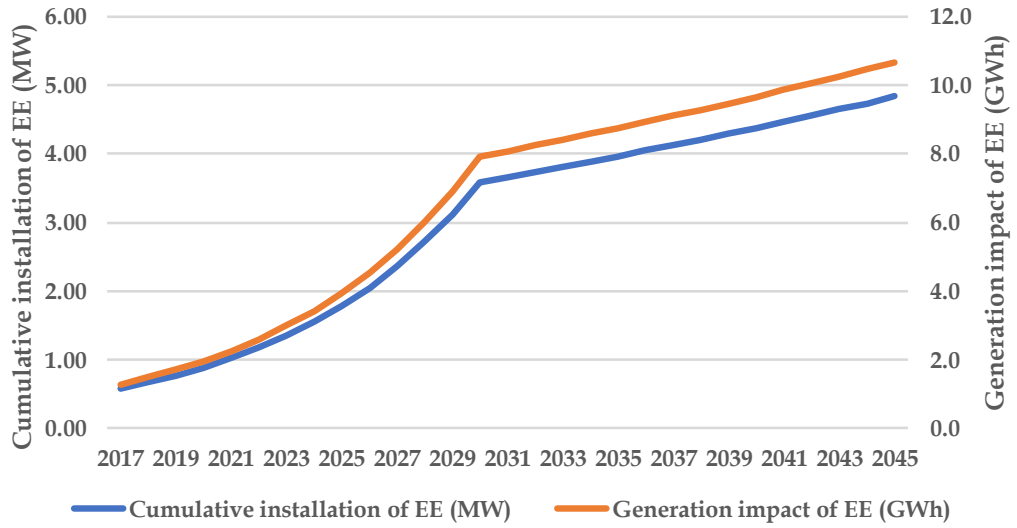
[24] Hawaii State Legislature. *Hawaii Revised Statutes § 269-96*. 2013.

[25] KIUC. KIUC 2016 Annual Net Energy Metering ("NEM") Program Activity Summary. May 11, 2017.

[26] Between 2012 and 2016, the average annual growth rates of cumulative DG-PV installation was 36.9% in Kauai County vs. 53.4% in the other counties.

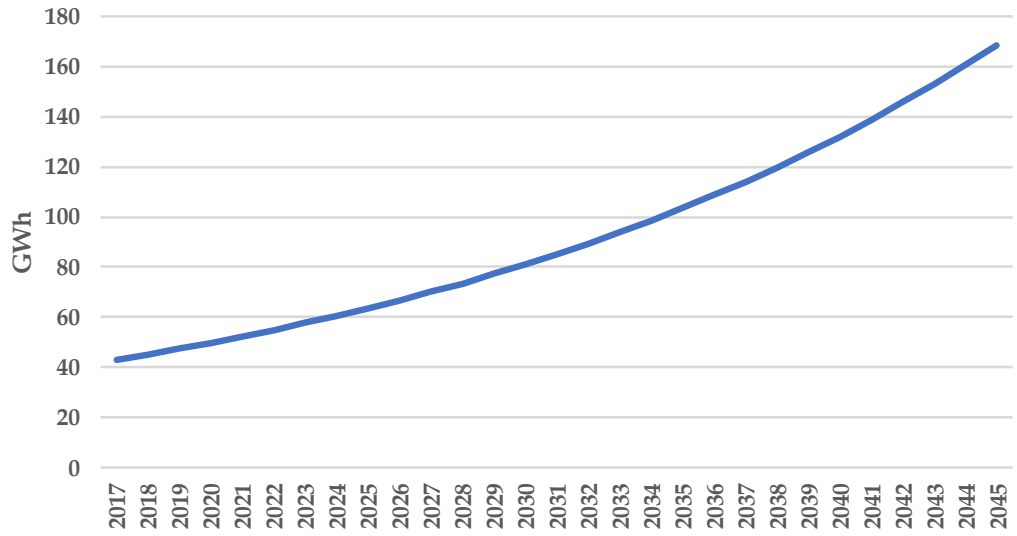
kW in 2012 to 0.36 kW in 2016 in Kauai County, and from 0.13 kW in 2012 to 0.43 kW in 2016 in the other counties.[27]

Figure 17. Projected cumulative installation and generation impact of EE for Kauai



Source: Docket No. 05-0075 - In re Public Utilities Commission's Investigation of Kauai Island Utility Cooperative's Proposed Revised Integrated Resource Plan and Demand Side Management Framework: 2016 Annual Modification and Evaluation Report ("AMER") and Energy Services Program Report. December 22, 2016. p.10; LEI analysis

Figure 18. Projected DG-PV generation for Kauai



Source: KIUC. 2016 Annual Net Energy Metering ("NEM") Program Activity Summary. May 11, 2017; LEI analysis

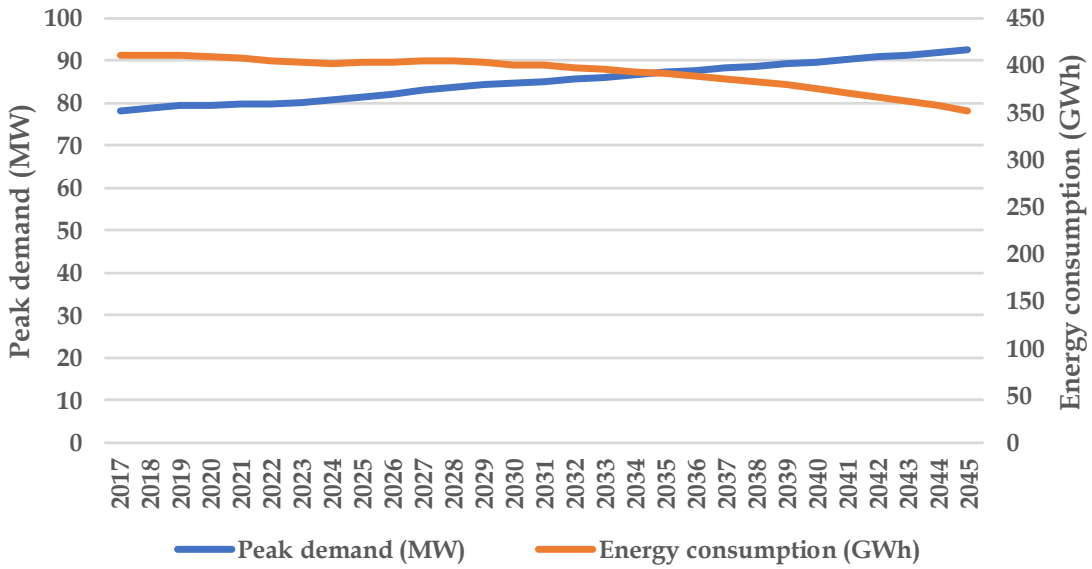
[27] Calculated using population data from DBEDT data warehouse.

LEI does not project EV adoption for Kauai since, according to a KIUC staff, there is little growth potential for EVs in Kauai.[28]

5.3 Net peak load and energy consumption

After adjusting the gross peak load for DG and EE, the resulting net peak load starts at 78 MW in 2017 and increases to 92 MW in 2045, at a CAGR of 0.6%. Due to the proliferation of DG-PV, the net energy consumption for Kauai is projected to decline from 410 GWh in 2017 to 352 GWh in 2045, at a CAGR of -0.5%.

Figure 19. Projected net peak load and energy consumption for Kauai



Source: LEI analysis

Note: Net peak load and energy consumption represent peak load and energy consumption after adjustment of EE, DG-PV, and EV.

[28] Based on an email exchange with Beth Tokioka on December 13, 2017.

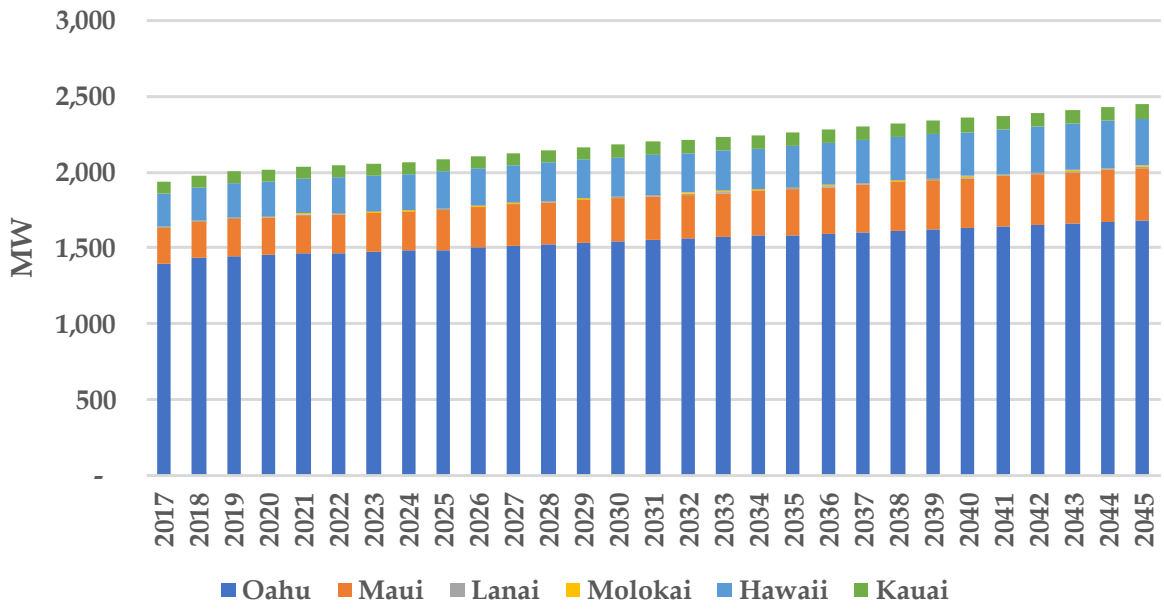
6 LEI's consolidated load forecast for the State of Hawaii

As mentioned in Section 3, the PSIP's load forecast methodology is consistent with the industry practice. Therefore, LEI choose to retain the PSIP's load forecast for counties where the HECO companies developed such forecasts and to conduct our own load forecast for Kauai using a consistent methodology. This section summarizes the consolidated load forecast for the State of Hawaii.

6.1 Projected gross peak load and energy consumption

The gross peak load for the State of Hawaii is expected to grow from 1,933 MW in 2017 to 2,447 MW in 2045, at a CAGR of 0.85%. Oahu accounts for more than 70% of the total gross peak load, followed by 13% from Maui, 12% from Hawaii, and 4% from Kauai (Figure 20).

Figure 20. Projected consolidated gross peak load for the State of Hawaii

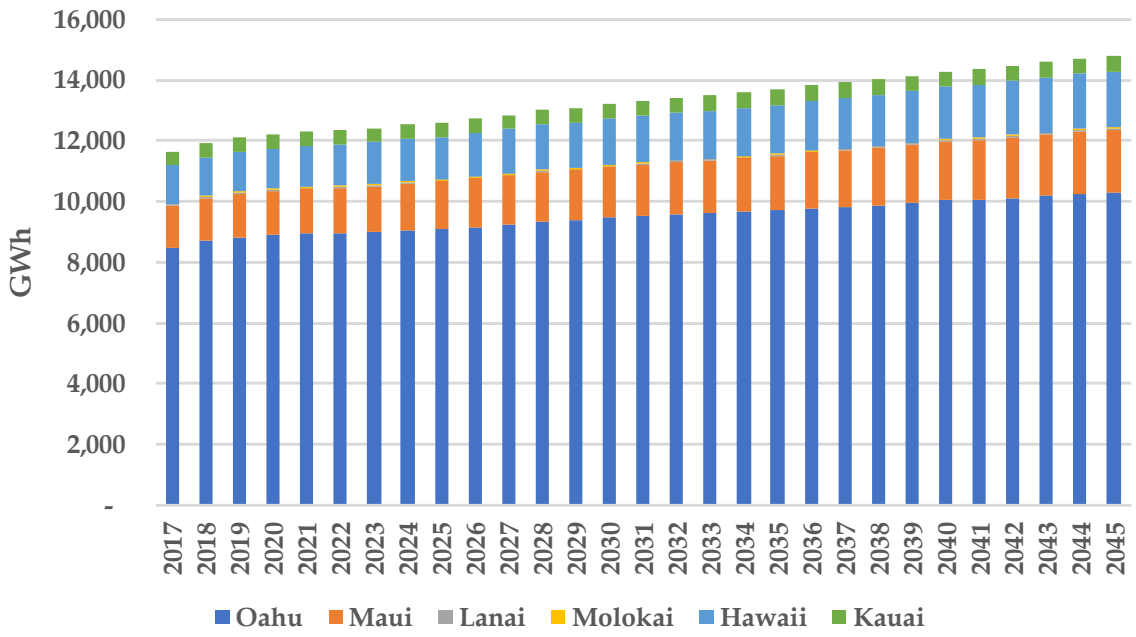


Source: PSIP. Update Report December 2016. J-50 – J-54; Kauai Island Utility Cooperative Annual Reports to PUC; UHERO; LEI analysis

Note: Gross peak load represents peak load before adjustment for EE, DG-PV, and EV.

The gross energy consumption for the state of Hawaii is projected to grow from 11,652 GWh in 2017 to 14,806 GWh in 2045, at a CAGR of 0.86%. Oahu accounts for more than 70% of the total gross peak load, followed by 13% from Maui, 12% from Hawaii, and 4% from Kauai (Figure 21).

Figure 21. Projected consolidated gross energy consumption for the State of Hawaii



Source: PSIP. Update Report December 2016. J-45 – J-49; Kauai Island Utility Cooperative Annual Reports to PUC; UHERO; LEI analysis

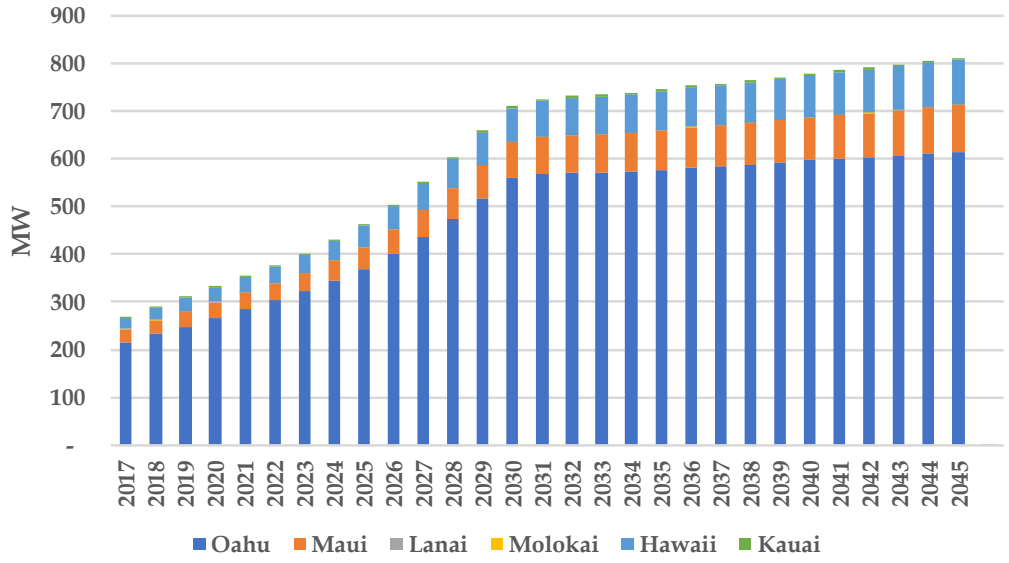
Note: Gross energy consumption represents energy consumption before adjustment of EE, DG-PV, and EV.

6.2 Assumptions of EE, DG-PV, and EV

Cumulative EE is expected to grow from 268 MW in 2017 to 710 MW in 2030, at a CAGR of 7.8%, and from 726 MW in 2031 to 812 MW in 2045, at a CAGR of 0.8%. The projected contribution of EE by island is in proportion with their gross peak load (Figure 22).

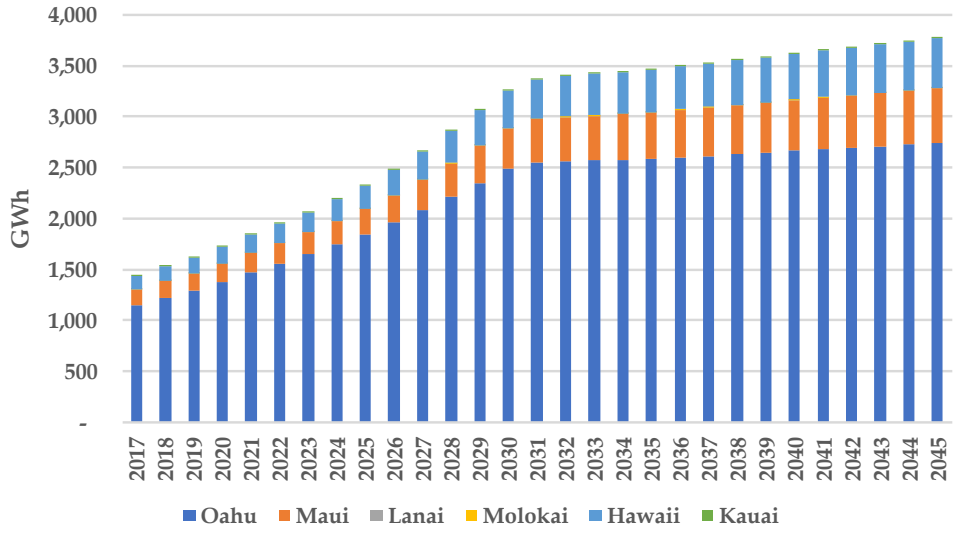
Consequently, projected generation impact from EE is projected to grow from 1,433 GWh in 2017 to 3,267 GWh in 2030, at a CAGR of 6.5%, and from 3,372 GWh in 2031 to 3,782 GWh in 2045, at a CAGR of 0.8% (Figure 23).

Figure 22. Projected cumulative EE for the State of Hawaii



Source: PSIP. Update Report December 2016. J-50 – J-54; Docket No. 05-0075 - In re Public Utilities Commission's Investigation of Kauai Island Utility Cooperative's Proposed Revised Integrated Resource Plan and Demand Side Management Framework: 2016 Annual Modification and Evaluation Report ("AMER") and Energy Services Program Report. December 22, 2016. p.10; LEI analysis

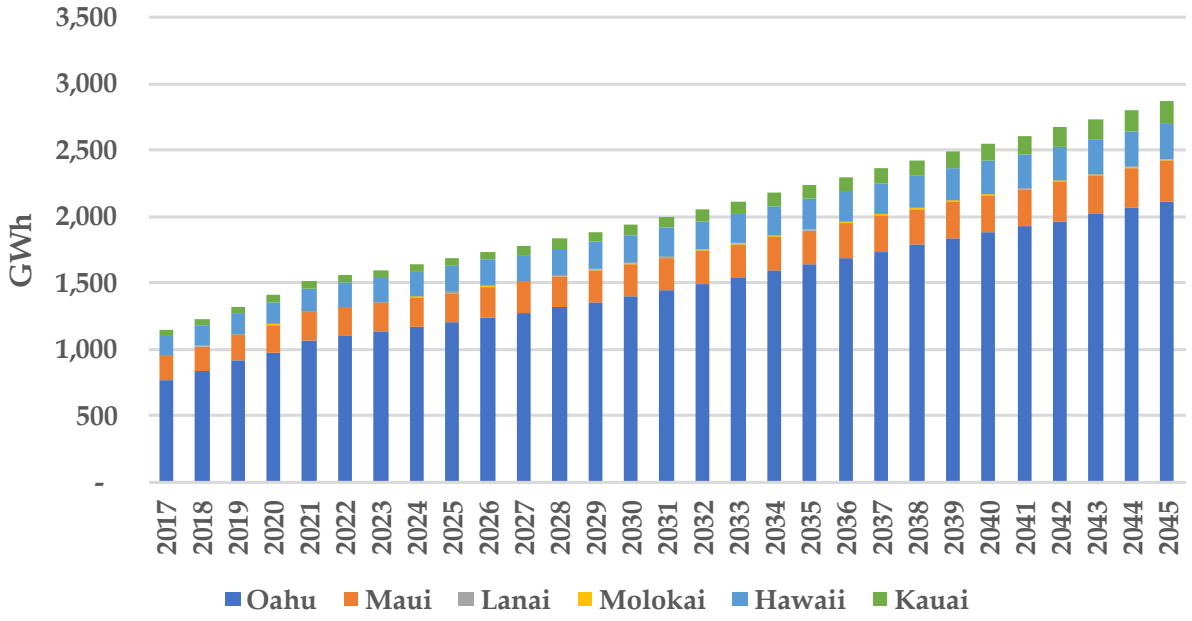
Figure 23. Projected generation impact from EE for the State of Hawaii



Source: PSIP. Update Report December 2016. J-45 – J-49; Docket No. 05-0075 - In re Public Utilities Commission's Investigation of Kauai Island Utility Cooperative's Proposed Revised Integrated Resource Plan and Demand Side Management Framework: 2016 Annual Modification and Evaluation Report ("AMER") and Energy Services Program Report. December 22, 2016. p.10; LEI analysis

Based on the analysis, DG-PV generation is expected to grow from 1,144 GWh in 2017 to 2,870 GWh in 2045, at a CAGR of 3.3%. Of all the islands, Kauai is projected to have the highest DG-PV growth (based on CAGR) at 5%, while Hawaii has the lowest DG-PV growth (based on CAGR) at 2.2%. As mentioned previously in Section 5.2, DG-PV penetration per capita is higher on the other counties than on Kauai, driving our projection for higher growth on Kauai in the future.

Figure 24. Projected DG-PV generation for the State of Hawaii



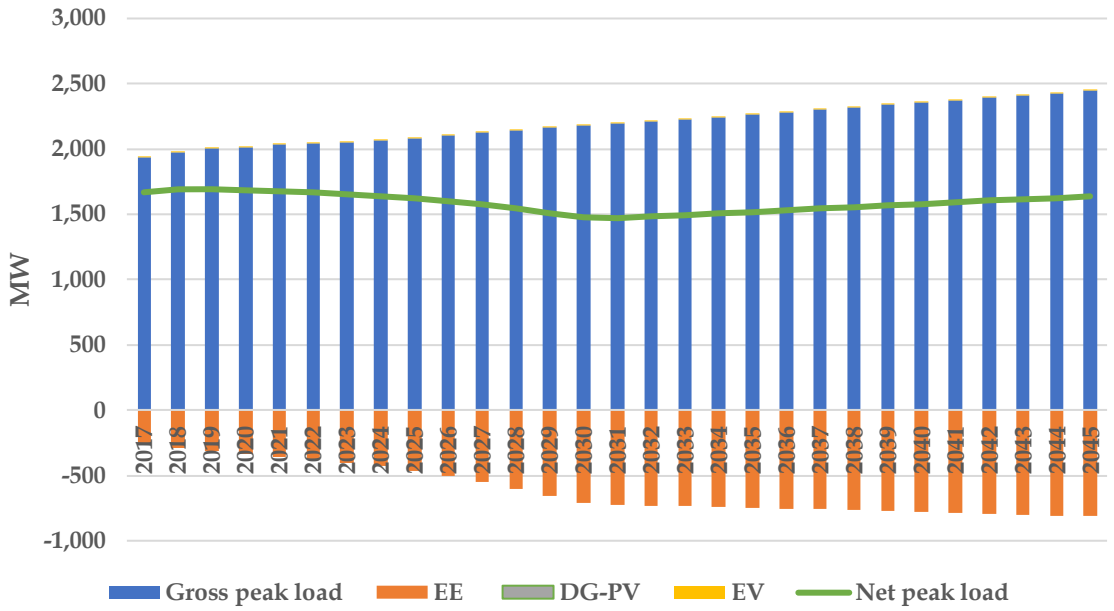
Source: PSIP. Update Report December 2016. J-45 – J-49; KIUC. 2016 Annual Net Energy Metering ("NEM") Program Activity Summary. May 11, 2017; LEI analysis

6.3 Projected net peak load and energy consumption and by customer type

Given the proliferation of EE programs, the net peak load for the state of Hawaii is projected to decline slightly from 1,665 MW in 2017 to 1,640 MW in 2045. The share of EE as a percent of the gross peak load is expected to grow from 14% in 2017 to 33% in 2045 (Figure 25).

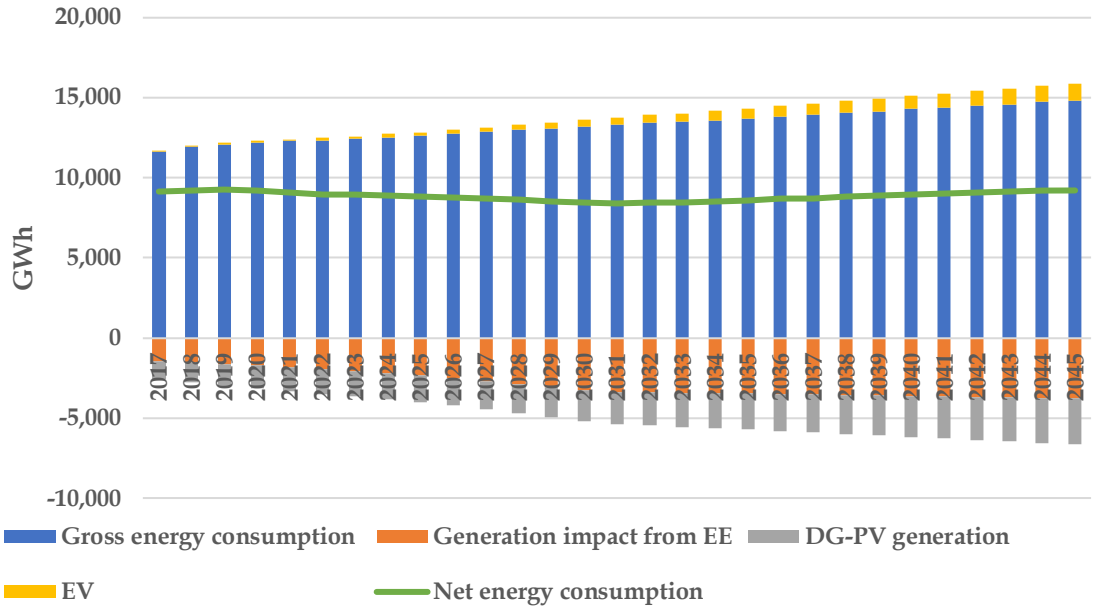
Similarly, with the combined effect of EE, DG-PV, and EV, the net energy consumption is expected to decrease from 9,121 GWh in 2017 to 8,395 GWh in 2031, at a CAGR of -0.6%, and increase at 0.7% CAGR from 2031 to 9,239 GWh in 2045. By 2045, EE is projected to contribute to more than 25% of the reduction in gross generation, followed by less than 20% from DG-PV. EV will contribute to 7% of the generation (Figure 26).

Figure 25. Projected consolidated net peak load for the State of Hawaii



Source: LEI analysis

Figure 26. Projected consolidated net energy consumption for the State of Hawaii

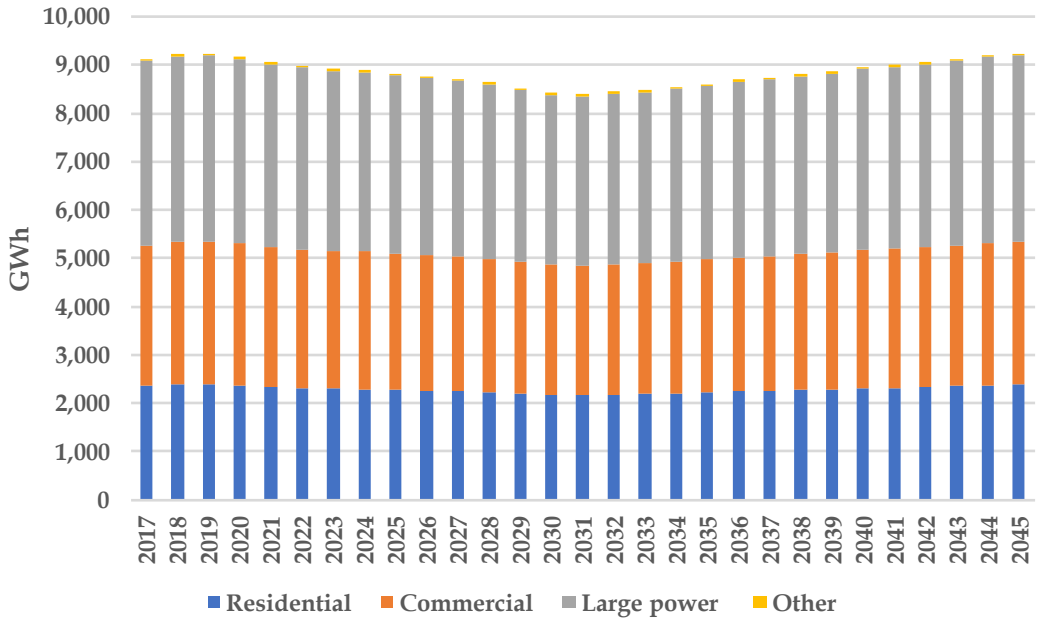


Source: LEI analysis

As of 2016, the total energy consumption or sales from HECO, HELCO, MECO, and KIUC was 9,587 GWh. LEI projects net sales by customer type using the ratio of the energy consumption

from residential, commercial, large power users and other sectors in 2016.[29] As shown in Figure 27, large power users account for more than 40% of the energy sales, followed by more than 30% from commercial, and more than 25% from the residential sector. Other sectors which include street lighting, EV, and irrigation account for less than 0.5% of the total sales.

Figure 27. Projected energy consumption by customer type



Source: HECO. Form 10-K For the fiscal year ended December 31, 2016. p. 5; MECO. Annual Report to the PUC of Hawaii for the year ending December 31, 2016. p. 304; HELCO. Annual Report to the PUC of Hawaii for the year ending December 31, 2016. p. 304; KIUC. 2016 Annual Report to the PUC. March 27, 2017. p. 47; LEI analysis

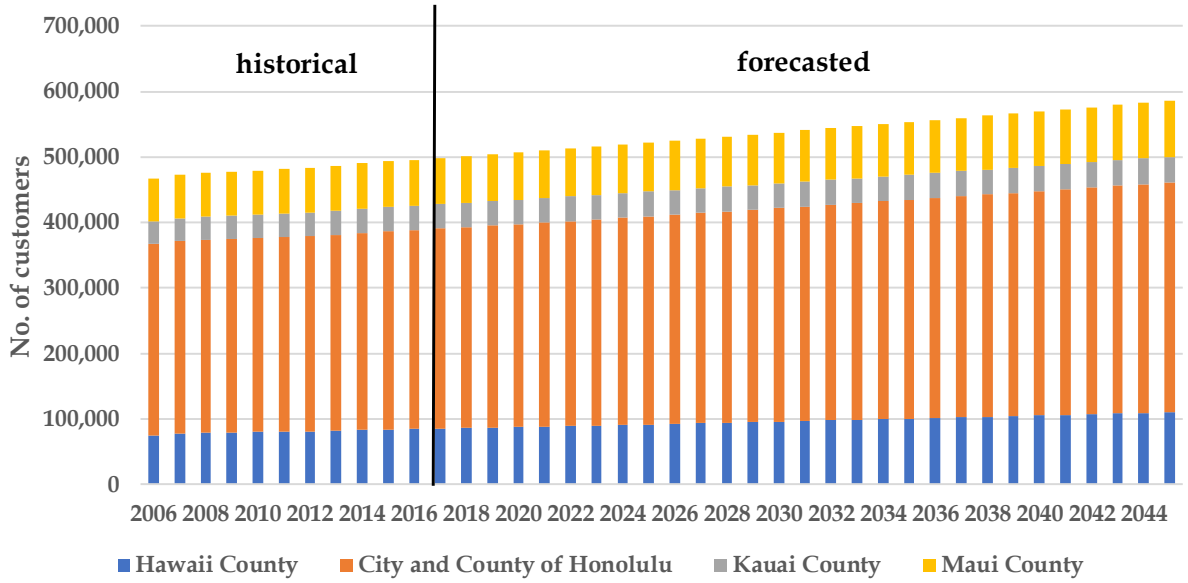
6.4 Number of customers

As of 2016, the total number of customers for the State of Hawaii is 496,048 customers.[30] LEI projected that the number of customers to grow at a stable rate of 0.6% per year from 2017 to 2045, based on the three-year rolling average of customer growth. The number of customers is expected to grow from 499,063 in 2017 to 586,377 in 2045. The City & County of Honolulu accounts for more than 60% of the customers, followed by 18% from Hawaii County, 14% from Maui County and the rest 7% from Kauai County.

[29] HECO. Form 10-K For the fiscal year ended December 31, 2016. p. 5; MECO. Annual Report to the PUC of Hawaii for the year ending December 31, 2016. p. 304; HELCO. Annual Report to the PUC of Hawaii for the year ending December 31, 2016. p. 304; KIUC. 2016 Annual Report to the PUC. March 27, 2017. p. 47.

[30] HECO Companies website. Available online at https://www.hawaiianelectric.com/about-us/power-facts and KIUC. 2017 Annual Report to the PUC, March 27, 2017. p. 47.

Figure 28. Historical and projected gross peak load and energy consumption



Source: DBEDT Data Warehouse; LEI analysis

7 Appendix A: Scope of work to which this deliverable responds

Task 1.5.2. Annual load and customer projections through 2045. CONTRACTOR shall prepare projections of potential electrical load and numbers of customers (residential, commercial, industrial) to be served through 2045 using historical, econometric, and other data as appropriate. The potential load projections shall include energy and capacity loads, (hourly annual load shapes). The projections shall account for distributed energy resources, energy efficiency goals, and demand response programs currently available and which may become available in the future to customers.

DELIVERABLE FOR TASK 1.5.2. CONTRACTOR shall provide its conclusions and all work related to annual load and customer projections through 2045, including energy and capacity as well as hourly annual load shapes for residential, commercial and industrial customers, including adjustments to account for the impacts of increased penetration of distributed energy resources, energy efficiency, and demand response programs. The CONTRACTOR shall provide an MS Excel file with forecast load projections, including annual energy and capacity loads through 2045 for residential, commercial and industrial customers. CONTRACTOR shall submit deliverable for TASK 1.5.2 to the STATE for approval.

8 Appendix B: List of work consulted

Docket No. 05-0075 - In re Public Utilities Commission's Investigation of Kauai Island Utility Cooperative's ("KIUC") Proposed Revised Integrated Resource Plan and Demand Side Management Framework: 2016 Annual Modification and Evaluation Report ("AMER") and Energy Services Program Report. December 22, 2016.

HECO. Form 10-K For the fiscal year ended December 31, 2016.

HECO. Electrification of Transportation – Strategic Roadmap. March 2018.

HELCO. Annual Report to the PUC of Hawaii for the year ending December 31, 2016.

KIUC. 2016 Annual Net Energy Metering ("NEM") Program Activity Summary. May 11, 2017.

KIUC. 2016 Annual Report to the PUC. March 27, 2017.

MECO. Annual Report to the PUC of Hawaii for the year ending December 31, 2016.

PSIP Update Report: December 2016.

Projected revenue requirements (2017 – 2045) under each ownership model

working paper prepared by London Economics International LLC for the State of Hawaii with support from Meister Consultants Group

April 13, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals; this document is one of several working papers associated with that engagement. This paper provides a background o

n revenue requirement calculations under different ownership models and how it informed the assumptions, inputs, and approach used by the Project Team to estimate the revenue requirements from 2017 to 2045 under each ownership model for each county. Additional evaluation of the impact of ownership models on projected cash flows and rates will be based on the estimated revenue requirements calculated in the Excel workbooks and elaborated further in Tasks 1.6.2 and 1.6.4, respectively.

The status quo ownership models are projected to have the lowest forecasted revenue requirements in Hawaii and Kauai counties. In Maui and Honolulu counties, the Investor-Owned Utility ("IOU") model has the lowest projected revenue requirements initially; in the longer-term, the Single Buyer ("SB") models are projected to be more cost-effective. The primary drivers of the estimated revenue requirements are return on rate base, anticipated fuel costs, estimated purchased power costs, and adjustments for capital expenditures ("capex") and debt repayment for the cooperative model. The relative importance of the drivers varies by county based on the current mix of utility-owned vs. independent power producer-owned ("IPP-owned") generation, forecasted capex, planned new capacity additions, and planned retirements or biodiesel conversions of thermal generation. Across all counties and ownership models, fuel costs and purchased power costs are among the most important drivers.

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List of acronyms

CAPM	Capital Asset Pricing Model
CFC	Cooperative Finance Corporation
CIAC	Contributions in Aid of Construction
DBEDT	Hawaii Department of Business, Economic Development, and Tourism
EIA	Energy Information Administration
EBIT	Earnings Before Interest and Taxes
GAPP	Generally Accepted Accounting Principles
HECO	Hawaiian Electric Company
HELCO	Hawaii Electric Light Company
IC	Invested Capital
IFRS	International Financial Reporting Standards
IOU	Investor-Owned Utility
IPP	Independent Power Producer
IRS	Internal Revenue Service
ITC	Investment Tax Credit
kWh	Kilowatt-hour
KIUC	Kauai Island Utility Cooperative
LCOE	Levelized Cost of Electricity
LEI	London Economics International LLC
MECO	Maui Electric Company
NARUC	National Association of Regulatory Utility Commissioners
NOPAT	Net Operating Profits After Tax
NREL	National Renewable Energy Laboratory

O&M	Operations and Maintenance
PBR	Performance-based Ratemaking
PPA	Power Purchase Agreement
PSIP	Power Supply Improvement Plan
PUC	Hawaii Public Utilities Commission
RAB	Regulatory Asset Base
REC	Regional Electricity Company
ROE	Return on Equity
ROIC	Return on Invested Capital
RPS	Renewable Portfolio Standards
RUS	Rural Utilities Service
SB	Single Buyer
T&D	Transmission and Distribution
TIER	Times Interest Earned Ratio
USDA	United States Department of Agriculture
WACC	Weighted Average Cost of Capital
YTM	Yield to Maturity

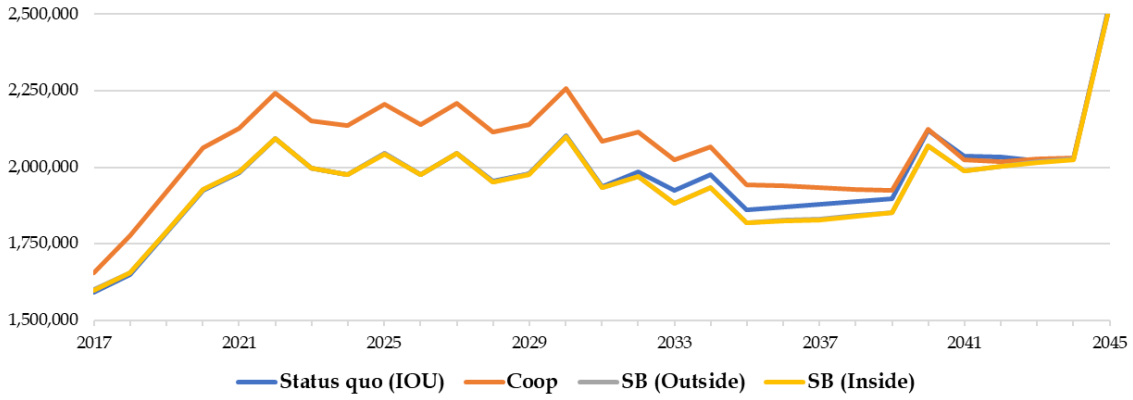
1 Executive summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which responds to Tasks 1.6.1 and 1.6.3 in the project scope of work, provides an overview of the revenue requirement calculations for 2017 to 2045 in the accompanying MS Excel workbooks. It describes the conceptual framework behind the forecasted revenue requirement calculations and differences among the ownership models that informs the Project Team's approach and assumptions used to project the revenue requirements for each county through to 2045 under four different ownership models: Investor-Owned Utility ("IOU"), cooperative ("co-op"), an independent Single Buyer ("SB"), and a ring-fenced SB within the utility.

Using the approach and assumptions described below in Section 4 and Task 1.4.2, the Project Team estimated revenue requirements out to 2045 under the status quo for each county: IOU for Honolulu, Hawaii, and Maui counties, and co-op for Kauai County. Then, revenue requirements for each county were estimated under the alternative ownership models, with the assumption that the transition happened at the end of 2016. The projections reflect the utilities' current capital costs and structure, planned capital spending on grid infrastructure, existing assets, resource plans, and current operating expenses.

It is important to note that this analysis assumed that the capital expenditure schedules and resource plans under Status Quo models are also adopted under the alternative ownership models. For transition to a co-op model, the analyses included some changes to the utility's operating costs, as will be discussed in Sections 4.1 and 4.2.

Figure 1. Projected Revenue Requirements for Honolulu County by Ownership Model ($000s, nominal)



Note: The line for SB (Outside) is hidden behind the SB (Inside) line.

The projections for Honolulu County in Figure 1 show revenue requirements growing under all ownership models in the near-term (2017 to 2022) due to rising fuel costs for the utility-owned thermal generation (drivers of revenue requirement changes are explained further in Section 5). Revenue requirements are projected to stabilize subsequently, with a spike in 2045 due to

biodiesel conversion of oil-fired generation units. The SB models are projected to have the lowest revenue requirements from 2025 onwards due to savings on expenses to procure power from planned new generation from Independent Power Producers ("IPPs") through competitive solicitations. Sections 4 and 5 provide a more detailed discussion of the approach and results of the analysis, respectively.

Figure 2. Projected Revenue Requirements for Hawaii County by Ownership Model ($000s, nominal)

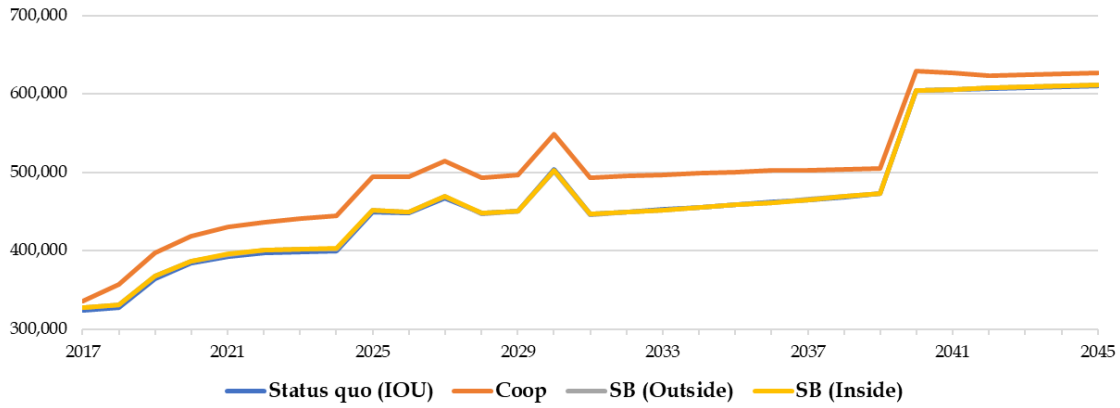
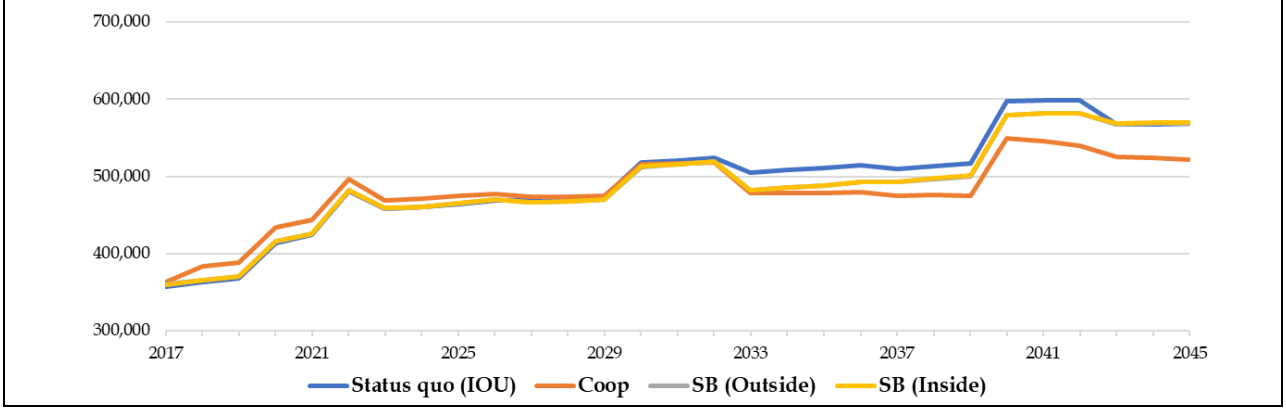


Figure 2 shows that revenue requirements are forecasted to rise steadily in Hawaii County under all the ownership models, with a spike in 2040 due to biodiesel conversion of utility-owned oil-fired generation units. The primary driver of this increase is the anticipated increase in purchased power costs (see graphics in Figure 14) due to the planned development of large geothermal and biomass plants. Projected revenue requirements are higher under the co-op model primarily due to the TIER level, planned capex, and debt repayment burden from the acquisition cost.[1] Sections 4 and 5 provide a more detailed discussion of the approach and results of the analysis, respectively.

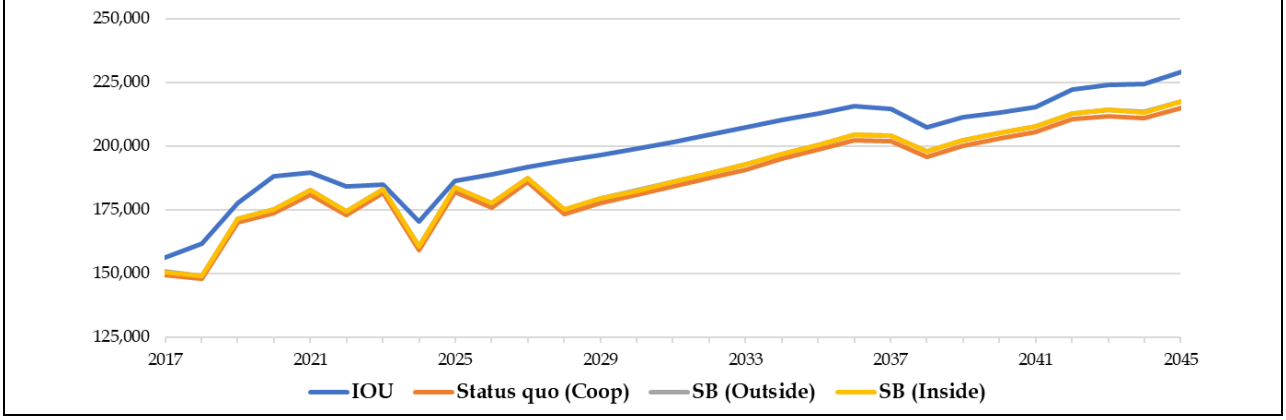
[1] For counties with incumbent IOUs, the revenue requirement calculations under a co-op model takes the HECO Companies' planned capex as a given input. Due to the TIER-based calculations for co-ops, new debt to finance planned capex has a higher impact on revenue requirements for co-ops than for IOUs.

Figure 3. Projected Revenue Requirements for Maui County by Ownership Model ($000s, nominal)



The revenue requirements in Maui County are projected to increase steadily under all ownership models in the short-term (2017-2022), largely due to the growing power supply costs from rising fuel prices and large additions of wind and solar generation capacity in 2020. After 2022, the increase in revenue requirements is expected to slow down, with upticks in 2030 and 2040 because of the biodiesel conversions. Revenue requirements are forecasted to be higher under the co-op model initially because interest coverage requirements under the TIER-based calculation are higher from acquisition costs and planned capex. However, the projected revenue requirements are largely similar under all ownership models. Sections 4 and 5 provide a more detailed discussion of the approach and results of the analysis, respectively.

Figure 4. Projected Revenue Requirement for Kauai County by Ownership Model ($000s, nominal)



The revenue requirements in Kauai County are forecasted to grow steadily under all ownership models in the short-term (2017-2020), driven largely by projected increases in purchased power costs as new capacity comes online. After that, revenue requirements are anticipated to stabilize before rising steadily again – after 2025 - under the IOU model and after 2029 under other ownership models. Sections 4 and 5 provide a more detailed discussion of the approach and results of the analysis, respectively.

The status quo ownership models are projected to have the lowest revenue requirements in most years in Hawaii and Kauai counties for the forecast horizon. The projections for Maui County show that the IOU model results in lowest revenue requirements initially; after 2027 however, the SB models are expected to be more cost-effective. In Honolulu County as well, the projected revenue requirements under the IOU model are initially lower than those under other models; the increased power supply expenses results in higher costs to ratepayers under the IOU model than under the SB models.

The primary drivers of revenue requirements are return on rate base, forecasted fuel costs, estimated purchased power costs, and adjustments for capex and debt repayment for co-op models. The relative importance of the drivers varies by county based on the current mix of utility-owned vs. IPP-owned generation, proposed capex, planned new capacity additions, and planned retirements or biodiesel conversions of thermal generation. Fuel costs and purchased power costs are among the most important drivers in all counties and ownership models. The proposed biodiesel conversions of existing thermal generation to meet renewable portfolio standards ("RPS") targets are projected to result in major increases in revenue requirements.

The Project Team also conducted sensitivity analyses which demonstrate that forecasted revenue requirements under a co-op model vary greatly with interest rates; even incremental changes can impact revenue requirements by millions every year. Figure 12, Figure 15, Figure 18, and Figure 21 show the results of these sensitivity analyses for Honolulu, Hawaii, Maui, and Kauai counties respectively.

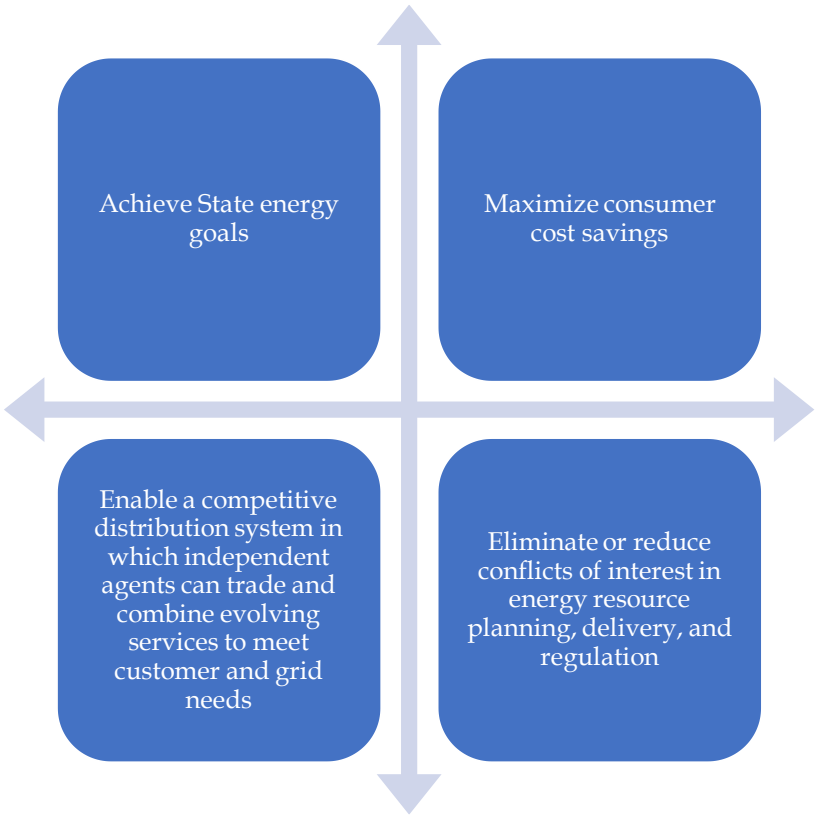
2 Introduction and scope

2.1 Project description

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission on a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[2] was contracted to perform this study.[3]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[4] listed in Figure 5.

Figure 5. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

[2] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[3] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[4] House Bill No. 1700 Relating to the State Budget.

The study will help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[5]

2.2 Role of this deliverable relative to others in the project

This deliverable is responsive to Tasks 1.6.1 and 1.6.3 in the project scope of work. It projects revenue requirements out to 2045 for the four utilities in the State of Hawaii under the four ownership models: Investor-Owned Utility ("IOU"), cooperative ("co-op"), independent Single Buyer ("SB"), and a ring-fenced SB within the utility. It discusses the principles of revenue requirements, its components, and how it is calculated under the different ownership models. Based on this discussion, the Project Team developed financial models to project revenue requirements. The analyses were conducted at a county level and are included in the accompanying MS Excel workbooks.

The Project Team conducted a thorough review of the utilities' rate case filings, regulatory filings, public annual financial reports and statements, various industry publications and data sources to collect the data and derive assumptions necessary for the revenue requirement calculations. The Project Team also reached out to the HECO Companies and KIUC through email for questions regarding some of the assumptions used in the modeling.

2.3 Future refinements

As noted earlier, this deliverable is subject to further refinement and modification if the Project Team received more updated information that will be useful in the modeling.

[5] Hawaii Contract No. 65595. Scope of Services.

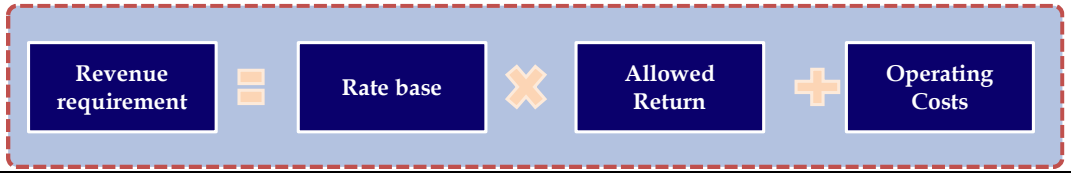
3 How are revenue requirements set under each ownership model?

The determination of revenue requirements is important to provide the utility with appropriate compensation for its services. It ensures the financial viability of the utility without placing an undue burden on ratepayers. Ownership models affect revenue requirement calculations to varying degrees, even without accounting for set-up, acquisition, or transition costs. Co-ops like KIUC use a very different approach to determining revenue requirements than IOUs since their customer-members are also the owners. On the other hand, SB models retain the inherent structure of the status quo utility, whether the utility is an IOU or a co-op; the costs of the SB's capital expenditure requirements and operations are incorporated into the utility's revenue requirement calculation. This section provides a discussion on how revenue requirements are set under each ownership model.

3.1 IOU

Revenue requirement identifies the expected amount of revenue the utility requires to cover its cost of service, which includes providing a return to its investors as well as its operating costs. Under an IOU model, the revenue requirements are estimated by determining the rate base and multiplying this by an allowed rate of return plus the operating costs as shown in Figure 6. The succeeding subsections provide the steps on how each component of the revenue requirements is calculated.

Figure 6. Revenue requirements formula used by an IOU



The rate base reflects the undepreciated portion of the utility's assets that have been financed using funds raised from investors at the costs of debt and equity embedded in the WACC. Therefore, the utility's operating income, obtained by multiplying rate base with WACC, is claimed first for debt servicing with the remainder returned to shareholders.

Under this basic calculation, utilities do not earn a return on operating costs, as these costs are simply passed on to ratepayers. However, some innovative Performance-Based Ratemaking ("PBR") structures may allow a utility to keep some of the savings from improving efficiency. PBR will be explored more in Tasks 2; the Project Team assumes a pass-through of operating costs for the deliverables corresponding to Tasks 1.6.

Revenue requirements are typically estimated beforehand and may not reflect the actual cost of service. Large fluctuations in fuel prices or a natural disaster may impact the costs incurred by the utility, which may lead to an adjustment in subsequent years.

3.1.1 Step 1: Calculating the rate base

Regulated Asset Base

"In its present form, the original cost or the net investment standard may be defined as one which measures the ratebase by summation of the actual legitimate costs of plant and equipment devoted to public service."

James C. Bonbright, *Principles of Public Utility Rates*, NY, 1961

Determining the Regulated Asset Base ("RAB") is a crucial component in the rate-setting process for an IOU. The RAB comprise of investments made by the utility to provide electric service and includes such items as utility-owned generation facilities, buildings, poles, wires, transformers, meters, vehicles, and computers. The RAB is the investment base on which a fair rate of return is applied to arrive at the allowed return to investors.

Ultimately, the choice of which approach to use to develop RAB estimates must depend on the specificities of the jurisdiction's regulatory and economic context. Such specificities include the perceived accuracy of utility accounting data related to the RAB, ongoing viability of existing assets on the books, and the impact that any values may have on tariffs and end-consumers' ability to pay for electricity supply.

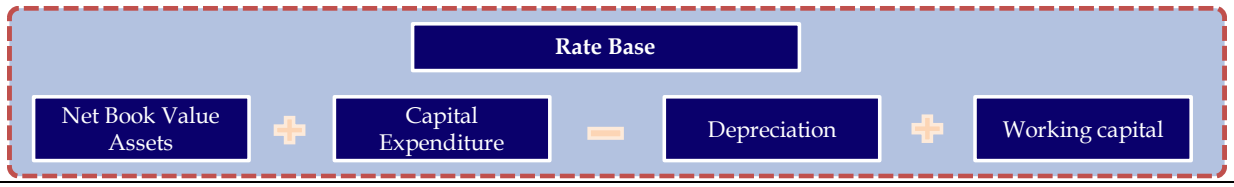
The components of the rate base generally include:

a) The net cost of plant in service, which is the book value of the physical assets owned by the utility such as generation plants, transmission, and distribution ("T&D") infrastructure, vehicles, land, and office buildings and supplies. It is typically by far the largest component of rate base. Capital expenditures ("capex") increase the value of net plant whereas depreciation and retirements decrease it.

b) Inventories of fuel and other material.

c) Regulatory assets created when regulators allow the utility to move certain costs from its income statement to its balance sheet.

Figure 7. Rate base formula



At a high level, the RAB at the end of a year is calculated as the sum of the net book value of physical and regulated assets at the beginning of the year, plus the annual capital expenditures, and minus the annual depreciation /amortization of assets, as illustrated in Figure 7.

3.1.2 Step 2: Determining the rate of return

The allowed rate of return essentially represents the amount of return that investors will receive on their investment, the regulated asset base. Setting the allowed rate of return requires balancing two equally important objectives: incentivizing continued investment in the sector and ensuring that consumers pay just and reasonable rates. There is ultimately no single correct allowed rate of return, but rather a "'zone of reasonableness' within which judgment must be exercised."[6] The lower bound of this zone represents the minimum return required to continue attracting capital, while the upper bound represents the return that an investment of similar risk could make elsewhere.

While there is "no objective, unequivocal method of ascertaining the cost of capital,"[7] there has developed over the last 20 years a fairly homogeneous approach that regulators have successfully used to developing appropriate proxies. This approach entails using the Weighted Average Cost of Capital ("WACC"), which assesses in appropriate ratios the actual underlying cost of debt and equity faced by the utility.

There are a number of methods that could be used to set rates of return for a utility. Historical rates, "a priori" (model-based), and the WACC have all been used by financial practitioners in determining what the rate of return should be for an investment. Each of these could be applied to determine what return the utility should be allowed to make, in order to provide enough incentives for investment. It must be noted that, of these three methods, only WACC is in common use in utility rate setting, although historical rates are sometimes used to set parameters utilized in estimating WACC.

The predominant method for setting the allowed rate of return is to use the regulated firm's WACC. In this approach, the allowed rate of return is set equal to the firm's WACC, suggesting that the firm is being compensated for its capital costs. This implies that the firm will make a nominal, but not an economic, profit.

WACC is the total cost, in percentage terms, of financing the firm's assets. It is calculated as:

$$WACC=[D\times R_D] + [(1-D)x\ R_E]$$

Where D=ratio of debt to assets, R_D=cost of debt (after tax), and R_E=cost of equity

To calculate the WACC, a number of inputs are required: the cost of equity, the cost of debt, and the capital structure to be used. They are each discussed below.

3.1.2.1 Approach to setting the cost of equity

The cost of equity is the most complicated of the inputs to the WACC formula. The main economic models used to determine the required cost of equity are the Capital Asset Pricing Model

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[6] Kahn, Alfred, *The Economics of Regulation: Principles and Institutions,* Cambridge, MA: MIT Press, 1988. P. 42/I.

[7] Ibid, p. 43/I.

("CAPM") and the many varieties of Arbitrage Pricing Theory ("APT") model. These models combine a long-run assessment of the riskiness of the firm in question with estimates of the prevailing risk-free rate and the rate of return of the market as a whole to project a required return on equity. The CAPM uses regression analysis of the historical return of the firm's equity, along with the historical return of the market as a whole to estimate beta, a measure of the company's risk. APT models, for example, the Fama-French Three Factor model, also use regression analysis of stock and market returns to evaluate risk but have additional factors such as the difference in returns to large and small companies.

The CAPM, however, is the most widely applied method used to determine the rate of return. The advantage of using CAPM is that it provides a theoretically justified cost of capital for equity. The disadvantage of CAPM is that it is somewhat backward-looking, with the beta, the market risk premium, and the risk-free rate set using historical measures. It has also been criticized on theoretical grounds – there is some evidence that it can systematically fail to predict returns accurately. Fama-French and other APT models are attempts to correct issues with CAPM.[8] There is, unfortunately, no consensus about which model is best, and APT models are significantly more difficult to estimate. As a result, CAPM remains the most standard way of estimating the cost of equity and is widely used in jurisdictions ranging from the US to Canada to Australia to Eastern Europe.

The CAPM model is characterized by the following formula:

$$R_E = R_f + \beta^*(R_M - R_f)$$

R_E is the return on equity, the expected return on an asset, given the other factors. R_f is the risk-free interest rate. R_M is the average return in the market on equity. Finally, β (beta) is the measure of asset risk in the model, formally the covariance of the asset and market returns, divided by the standard deviation of the market returns.

The most important element of the CAPM is beta. Beta is a measure of the tendency of returns to the asset to be correlated with the returns to the market as a whole. In other words, beta measures how closely an asset is linked with the market (called the systematic risk of the asset). The theory underlying CAPM states that investors are only compensated for systematic risk, so the beta determines how much return an investor should demand to invest in a particular asset. This "required return" is the cost of equity for the asset.

3.1.2.2 Approach to setting the cost of debt

There are three options for estimating the cost of debt. The ideal way to find the current cost of debt is to use the firm's market debt rate. Although this method can only be used for firms whose bonds are traded in a liquid market, the current yield to maturity ("YTM") can be used to reflect the most up-to-date view of the firm's rate on debt.

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[8] The main critics of CAPM suggest that there is more to risk than just the tendency of an asset to move along with the market. APT models compensate for this potential problem of CAPM by including more variables in estimating the riskiness of the asset.

There are several challenges to using this method. A determination must be made about the liquidity of the market for the firm's debt, and the validity of the prevailing market YTM. If the market is not adequately liquid, the historical (book) rate for the debt, or a deemed rate, might be used as a substitute. Also, if any of the debt is held by affiliated parties, then it is more appropriate to use a deemed rate, to avoid the potential impact of possibly abusive self-dealing. Finally, if the debt has special features, such as being callable or convertible, then the rate will differ from the true market rate for simple debt. Despite all these potential problems with the debt, using the market rate is considered the best way to estimate the current cost of debt for a firm.

An alternative to using the market rate of debt, especially for firms that have bank debt, or debt that is not frequently traded, is to use the book rate of debt. For bank loans, the contracted rate of interest can be used; for floating rate debt, the current floating interest rate is most appropriate, and, for bonds, the most recently available YTM can be used.

If the appropriate interest rate on debt is in question, it may be necessary to assign a deemed rate to that debt. This can happen, for example, if the firm's credit rating changes significantly, or if the firm's debt has unusual features, like embedded options, which distort the rate of interest. To make the deemed rate as close to the market rate as possible, the deemed debt rate should be set to using the risk-free rate and a premium to account for the extra risk of the firm.

3.1.2.3 Approach to setting the capital structure

The simplest option for determining the capital structure is to use the utility's actual structure. This, however, may create an incentive for the utility to take on more debt than is appropriate, particularly if the allowed costs of equity and debt fluctuate over time. An alternative is to set a fixed capital structure and make the determination of WACC based on that, rather than on the actual structure. An intermediate option is to set a target range for capital structure and to allow any structure within that range (common in the US and used in Ontario).

The downside to requiring a particular structure is that it restricts management's freedom to capitalize in an optimal manner. In many jurisdictions, the capital structure was formerly tightly controlled to reduce the risk of bankruptcy of the utility. Newer regulatory systems set deemed capitalization structures and allow utilities greater freedom in financing.

3.1.3 Step 3: Calculating the operating costs

Operating costs are the expenses related to operating and maintain the utility. It does not include capital outlays. Operating costs include fuel costs, purchase power expenses, other operations and maintenance ("O&M") costs, depreciation, and taxes, as discussed below:

a) Fuel costs are incurred from utility-owned generating plants that run on fuel sources like oil, biomass, or biodiesel that must be purchased. It is a function of both electricity generated by these plants and fuel prices. Other fixed and variable O&M) costs of these plants are included in (c) below.

b) Purchased power expenses refer to the utility's cost to purchase power generated by plants owned by IPPs as well as behind-the-meter generation with grid export

capability. Each IPP is paid according to the terms specified in its Power Purchase Agreement ("PPA") with the utility.

c) Other O&M costs include the labor and non-labor O&M costs associated with production, transmission, distribution, customer accounts, customer service, and administrative functions of the utility.

d) Depreciation of net plant is also expensed in the same period. It reflects the value of the asset used up over that period. If a plant has a 10-year life, a utility uses one-tenth of its value every year. This analysis assumes straight-line book depreciation – the annual depreciation expense for an asset is obtained by dividing its initial cost by the asset life in years. Higher rates of book depreciation lower the utility's taxable income and thus its tax expenses.

e) Taxes can be of several types: state and federal income taxes, payroll taxes, public service tax, Public Utilities Commission ("PUC") fees, and franchise tax. Public service tax, PUC fees, and franchise tax are levied on operating revenues and are thus known as revenue taxes. Income taxes are charged on taxable income, which is obtained by deducting interest expense from Earnings Before Interest and Taxes ("EBIT").

3.2 Co-op

An electric co-op's revenue requirement calculation is based on very different principles from the IOU's. An IOU receives financing from debt and equity investors at prevailing market rates, so that its revenue requirements must provide sufficient returns to its lenders *and* shareholders. Otherwise, its financial integrity will suffer and make it harder to raise capital on reasonable terms, and the financing will ultimately get more expensive.

Maintaining financial integrity is also important to a co-op, but its revenue requirement target is mainly designed to meet its debt obligations. A co-op's equity is held primarily by its customer-members, who make contributions for service and not with a set expectation of return. Therefore, the revenue requirements of a co-op are set using a Times Interest Earned Ratio ("TIER") level, as discussed in Task 1.4.2. TIER is a solvency ratio that measures a co-op's ability to meet its long-term debt obligations. It is calculated by dividing the sum of net income and total interest expense by total interest expense. Net income is essentially operating margin in the case of a co-op. The formula of the TIER is:

$$TIER = EBIT/(Interest\ Expense)$$

$$TIER = (Interest\ Expense + Margins)/(Interest\ Expense)$$

$$TIER = (Revenues - Operating\ Expenses)/(Interest\ Expense)$$

The ratio measures how many times a co-op can cover its interest expenses from its pre-tax earnings. Although the United States Department of Agriculture's ("USDA") Rural Utilities Service ("RUS") loan agreements require a minimum TIER of 1.25 for distribution utilities, the

PUC set the regulated TIER level for KIUC at 2.27, or equivalent to an RUS TIER of 2.00.[9] It is important to note that the analysis uses this TIER level for KIUC (and IOU to co-op calculations) as this is a significant contributor to the results. The operating revenue remaining after operating expenses and debt service is paid for is a co-op's margin for that year. The revenue requirement for an electric co-op is set so that it earns sufficient margins to achieve the target TIER level. The margins help the co-op to maintain financial stability and make the necessary investments on the grid.

Co-op TIER levels

In KIUC's last rate case, it had applied for rates based on a regulatory TIER level of 2.50 in its last rate case. The rates that the PUC eventually approved were lower than what KIUC had applied for and was equivalent to an effective regulatory TIER level of 2.27, or an RUS TIER of 2.00.

There is also a difference between Regulatory TIER and the RUS TIER that KIUC reports to its lenders. The Regulatory TIER reflects the TIER at proposed rates without inclusion of any amortization of the acquisition adjustment from KIUC's purchase of Kauai Electric's assets. The TIER that KIUC reports to lenders includes this adjustment. Since the Project Team is including amortization of the acquisition premium (amount paid over the net book value of the assets of the IOU) in the TIER, it will use the RUS TIER of 2.00.

KIUC reports the actual TIER level in any given year in its regulatory filings. Since the rates haven't been updated since the last rate case in 2009, actual TIER levels depend on operating expenses and sales for that year. The Project Team's analyses assumes that revenue requirements are sized to achieve the target TIER level in each year.

From the formula for TIER level, the following can be inferred:

$$TIER = (Revenues - Operating\ Expenses)/(Interest\ Expense)$$

$$Revenues - Operating\ Expenses = Interest\ Expense * TIER$$

$$Revenue\ Requirement = Interest\ Expense * TIER + Operating\ Expense$$

The primary components of revenue requirement for a co-op are:

1) Interest expense

   a) Capital structure helps to determine how much debt the co-op can carry. A higher debt-capital ratio increases the interest expense and thus the revenue requirements. This is opposite for an IOU, which can increase leverage to lower the WACC.

[9] Kauai Island Utility Cooperative. Docket No. 2009-0050. *Application of Kauai Island Utility Cooperative for Approval of Rate Changes and Increases, Revised Rate Schedules and Rules, and Other Ratemaking Matters. Volume 1.* June 2009.

b) Interest rates are lower for co-ops than IOUs. Co-ops have access to low-cost debt from public and private sources that IOUs do not, enabling them to lower their financing cost.

2) TIER level – set by the regulator.

3) Operating costs – same as for IOU, except for tax expenses are lower for co-ops because they are exempt from federal income taxes.

3.3 Single Buyer (outside)

The Project Team assumes that an independent SB will function alongside the incumbent IOU or co-op in their current level of vertical integration. The SB will be set up as a profit-neutral entity, generating just enough revenues through fees added to electricity rates to recover its expenses. There are initial costs of creating and setting up an SB, and then ongoing expenses for its operations, as discussed in the previous working papers (Task 1.3.1).

The SB's revenue requirements are also its expense categories, which are:

1) Purchased power expense

   The SB will be the counterparty to power purchase agreements ("PPAs") with IPPs and will purchase power from IPPs on behalf of the utility. The Project Team assumes that an SB can procure power at 3% lower costs than an IOU,[10] as discussed in more details in Task 1.4.2. Since a co-op also operates with the principle of cost minimization, the Project Team assumes that an SB operating alongside a co-op will have no measurable downward impact on purchased power costs relative to the co-op model. Since current IPPs already have long-term PPAs with the utility, the lower costs will only apply to generation from IPP-owned plants that will come online in the future or to a current IPP-owned plant with a service life longer than its current PPA term.

2) Capex

   The SB will require up-front expenditure on equipment, furniture, computers, and other similar assets.[11] Subsequently, the capex will be incurred periodically as the assets are replaced or upgraded.

3) System planning and procurement – O&M costs

[10] This assumption is based on LEI's review of several quantitative studies on the benefits of competition and unbundling (as detailed in Task 1.4.2), which showed efficiency gains between 3% and 14%. For this report, LEI assumed a conservative base case of 3% gains from the increased competition.

[11] Capex needed under the SB model is discussed in Task 1.4.2.

Once established, the SB will incur expenses from its day-to-day operations, primarily from labor and non-labor O&M expenses such as employee compensation, training, software licenses, and other office expenses.

4) Rent

The SB is assumed to rent a separate office from the incumbent utility as required by the Single Buyer Rules (discussed in Task 1.3.1).

5) Audits

The SB will be audited annually to ensure it is complying with its responsibilities.[12]

For the total revenue requirement calculations, the utility's original purchased power costs are replaced by the SB fee and its O&M costs are lowered due to the separation of planning and procurement functions.

3.4 Single Buyer (inside)

A ring-fenced SB unit within a utility, even if it performs the same functions as an independent SB, will have a different impact on revenue requirement calculations. SB's revenue requirement is included in the utility's total revenue requirements; however, an IOU can include the SB assets and capex in its rate base and earn a return on them. The operating expenses are passed through to the ratepayers.

On the other hand, the capex of ring-fenced SB within a co-op is financed through a combination of debt and patronage capital, similar to other capex of the co-op discussed in Section 3.2. The portion financed through debt thus affects revenue requirement through the TIER-based calculation.

3.5 Similarities and differences

As discussed in previous sections, there are significant differences, and some similarities, among the various ownership models in terms of determining the revenue requirements. The major difference lies in the methodology to calculate the utility's revenue requirements. On the one hand, an IOU's revenue requirement is designed to provide the PUC-approved return on equity for its shareholders. On the other hand, a co-op must meet the PUC-mandated interest coverage requirement to ensure financial viability. This is because IOUs raise capital through debt and equity providers, whereas co-ops have access to low-cost debt from specific lenders and are not targeting a set rate of return on their equity.

Revenue requirement determination is very different between the IOU and co-op models. The IOU model seeks to provide a fair rate of return to its investors; therefore, an IOU's revenue requirement includes an allowed return for its shareholders. However, a co-op simply has an

[12] This is a requirement as discussed in Task 1.3.1.

interest coverage requirement to ensure financial viability. Unlike an IOU, a co-op can borrow at below market rates from specific lenders that an IOU does not have access to.

In both the SB models, revenue requirement is largely determined by whether the underlying utility is an IOU or a co-op, with the SB operating costs passed on to the utility. The primary difference between the two is the treatment of capex for SB assets – a ring-fenced SB's assets are financed by the underlying utility with a combination of debt and equity, whereas an independent SB's capex is passed on to the utility and then to ratepayers. The table below summarizes these similarities and differences.

IOU	Co-op	SB (outside)	SB (inside)
Revenue determination			
Allowed return on rate base	Set coverage ratio on interest payments Margins on expenses assigned to members' patronage accounts	All expenses passed on to the utility through a separate charge and ultimately to the consumers	All expenses added to utility revenue requirement IOU can rate base the SB's assets SB capex increases the co-op's debt
Source of capital			
Debt and equity capital markets	Low-cost debt from co-op-specific lenders Equity from members as patronage capital	SB fees charged to the utility	Through the utility
Cost of capital			
WACC (based on market rates for debt and equity)	Interest-rate of debt	N/A	Through the utility
Revenue requirement components			
Rate base * WACC + opex	Interest exp * TIER + opex	Purchased power cost + SB capex + SB opex + Rent + audit	Purchased power cost + SB opex + Rent + audit (SB capex included in IOU rate base)

4 Revenue requirements assumptions and approaches under each ownership model

The Project Team conducted a county-level analysis for the four electric utilities in the State of Hawaii. First, projections for revenue requirement and its components were estimated under the status quo, namely IOUs in Honolulu, Maui, and Hawaii counties, and co-op in Kauai county. Then, the components were adjusted using assumptions about transitions to other ownership models (e.g., IOU to co-op, IOU to SB, co-op to IOU, co-op to SB) to estimate revenue requirements through 2045 for each county under each ownership model. The approach and assumptions used are detailed in the subsequent sections.

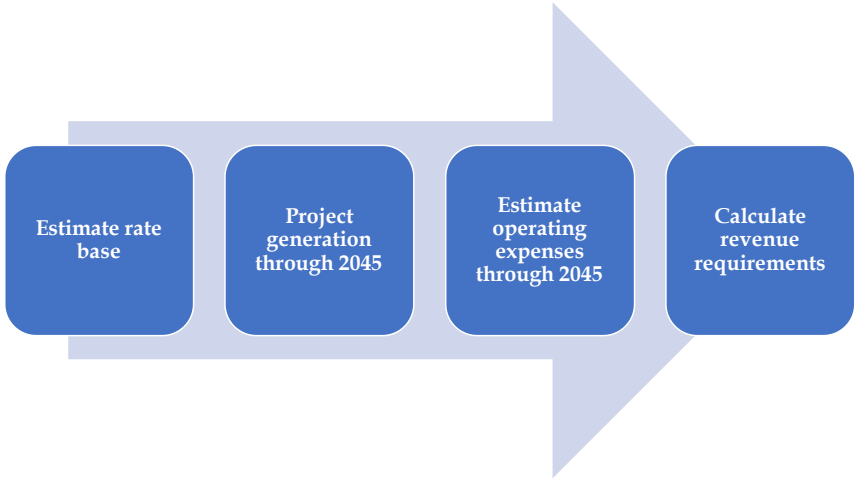
4.1 Approach

The Project Team created a financial model to estimate the revenue requirements through to 2045 for all four counties under the status quo, i.e., IOU for Honolulu, Maui, and Hawaii counties and co-op for Kauai County. The estimates are based on the methodology used by the utilities to calculate revenue requirements in their current or most recent rate cases and data from their rate cases or regulatory filings. Once these base case scenarios were completed, the Project Team calculated the revenue requirements for all counties assuming the three alternative models, using the methodology and assumptions discussed in Task 1.4.2 and Section 4.2.

4.1.1 Status quo – IOU

The starting point of the modeling was to collect information on the current IOUs – Hawaiian Electric Company ("HECO") on Honolulu County, Hawaii Electric Light Company ("HELCO") on Hawaii County, and Maui Electric Company ("MECO") on Maui County. The data for the IOU's revenue requirement components for 2016 and/or 2017 was collected from their current or most recent rate case filings as well as their annual reports to the PUC. Figure 8 illustrates the process to calculate the projected revenue requirements under the IOU model. Each step will be discussed in detail below.

Figure 8. Simplified steps in estimating the revenue requirements under the IOU model



1. Rate base was estimated from its components.

$$Rate\ Base = Investment\ in\ Assets - Funds\ from\ NonInvestors + Working\ Cash\ Required$$

Investment in Assets is the sum of the net cost of plant in service, fuel inventory, materials and supplies inventory, and various regulatory assets.

- **Net cost of plant in service** is estimated using current net book value of plants provided by the HECO Companies, utility capex plans from the Power Supply Improvement Plan ("PSIP"), plant depreciation rates and regular asset retirements from their rate cases, and the retirement schedule for the IOU's current generation plants from the PSIP report.

- **Fuel inventory** is estimated using inventory days-on-hand from rate case filings and fuel consumption by utility-owned plants calculated from generation projections (detailed below).

- The actual 2016/2017 amounts for **materials and supplies inventory**, other regulatory assets, the different categories of funds from non-investors (except for accumulated deferred income taxes), and working cash requirements are used for projections through 2045 based on information from rate cases or are tied to inflation, plant balances, or customer sales forecasts from the PSIP based on LEI analysis.

Likewise, **Funds from Non-Investors** comprised of unamortized Contributions in Aid of Construction ("CIAC"),[13] customer advances,[14] customer deposits,[15] accumulated deferred income taxes,[16] unamortized state Investment Tax Credit ("ITC"),[17] and other regulatory liabilities

- Accumulated deferred income taxes are calculated using each year's net increase/decrease based on:

$$Deferred\ Income\ Tax = (Tax\ depreciation - Book\ depreciation) * Effective\ Tax\ Rate$$

Investors only get a return on the portion of utility assets for which they provided financing. Therefore, Funds from Non-Investors is deducted from Investment in Assets because it represents utility assets that were financed by funds that the utility owes to its customers or the government.

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[13] CIAC is money or property that a developer or customer contributes to fund a utility capital project.

[14] Customer advances are funds paid by customers to the utility which may be refunded in whole or in part.

[15] Customer deposits are collected from customers who do not meet the utility's criteria for establishing credit at the time they request service.

[16] Accumulated deferred income tax represents the cumulative amount by which tax expense has exceeded tax remittances. It results from differences between depreciation and accelerated depreciation recorded for accounting purpose and those used for the calculation of income taxes.

[17] Unamortized ITC reduce tax payments in the year the credit originates but are amortized for ratemaking purposes.

The utilities also need working cash on hand to account for the difference in timing between when a cost is incurred versus when it receives payment for it.

2. Generation was projected through 2045

Data on operational parameters of power plants and price forecasts were used to project generation, and thus estimate fuel costs and purchased power expenses, at plant-/unit-level.

- Projections for IOU-owned generation were based on plant data such as capacity, fuel used, in-service year, retirement year, capacity factor, and heat rate from rate cases, the PSIP report, utilities' annual report to the PUC, the PUC's annual report, fuel price forecasts from the PSIP, and assumptions for fixed and variable O&M expenses from EIA's Assumptions to the Annual Energy Outlook 2017.

- For current IPP-owned plants, the Project Team used information on plant capacity, type, and actual electricity generation in 2016 from utility filings and paid third-party data sources. The utilities' rate case and regulatory filings, and the PUC's annual reports also contained details on PPA terms. The Project Team made assumptions about asset life of power plants based on industry standards obtained from Energy Information Administration ("EIA").

- The HECO Companies provided data on plant capacity, type, and in-service date for the future IPP-owned generation in the PSIP report. The supply resource capacity factors and PPA prices were estimated using projections for Levelized Cost of Energy ("LCOE") by plant type from National Renewable Energy Laboratory ("NREL") and Lazard (for battery), adjusted to Hawaii using a cost index.

3. Operating expenses was estimated through 2045

Operating expenses include fuel and purchased power costs, other O&M costs, depreciation expense, amortization of state investment tax credits, and taxes:

- **Fuel and purchased power expenses** were based on generation projections above.

- **Other O&M** were projected using actual 2016 expenses tied to inflation and forecasts of electricity sales or population. Transmission and distribution ("T&D")-related O&M expenses were indexed to electricity sales and expenses for Customer Accounts and Customer Service to population; both were adjusted for inflation. Administration & General expenses were projected based on actual 2016 expenses adjusted for inflation.

- **Amortization of state ITC** was calculated based on info from rate case filings.

- **Depreciation expenses** were derived from calculations for the net plant.

- **Revenue taxes** were calculated as a percentage of each year's operating revenues. Payroll taxes were estimated as a fixed percentage of Other O&M costs, based on rate case filings. Income taxes were calculated using effective federal and state income tax rates on taxable income.

- The Project Team used the costs of debt provided in rate case filings to calculate interest expenses.

4. Revenue requirements were estimated based on the formula below, as discussed in Section 3.1.3.

Revenue Requirement = Rate Base * WACC + Operating Expense

4.1.2 Status quo – KIUC[18]

The Project Team used a similar approach to estimate KIUC's operating expense categories such as power supply costs, taxes, and depreciation expenses. KIUC provided capex plans for 2017 to 2021; for longer-term modeling of capex, the five-year average was adjusted for inflation to project capital expenditures beyond 2021.

The cost of debt was calculated using historical interest expense data and assumed to remain constant throughout the forecast horizon. The Project Team used the current debt-capital ratio of 65% based on KIUC's current capital structure to estimate the amount of new debt raised by the co-op for planned capex. This was used to calculate the co-op's interest expenses and debt service obligation, upon which its revenue requirement is calculated.

4.1.3 IOU to co-op[19]

The Project Team assumed that the acquisition of the IOU is entirely debt-financed, with the terms of debt assumed to be the same as current terms for KIUC. The assumption of 100% debt-financed acquisition is based on KIUC's experience in purchasing Kauai Electric; KIUC's current rates on its low-interest loans are the most representative terms available for a hypothetical co-op that would acquire the HECO Companies' assets.

The co-op is assumed to build its equity in the form of patronage capital gradually. New debt and patronage capital retirements were calculated using the same approach as for KIUC's status quo. The projections of various operating expenses under the IOU model were also retained for the co-op model; the differences between IOU and co-op models in terms of underlying costs are related to capital structure, cost of debt, and exemption from federal income taxes.

The revenue requirements were then estimated using the TIER approach, which was described in Section 3.2. The Team used KIUC's TIER level of 2.00 for the hypothetical co-ops in counties with an incumbent IOU.

[18] For Kauai County.

[19] For Honolulu, Hawaii, and Maui counties.

4.1.4 IOU to SB (outside)[20]

An SB fee corresponding to the SB's capex and operating costs will be charged to the IOU. Under the SB model, all future power is assumed to be procured through competitive solicitations which result in long-term power procurement contracts, as opposed to the IOU model where some future power plants are owned by the utility. Otherwise, the incumbent IOU continues to own and operate its existing generation assets.

4.1.5 IOU to SB (inside)[21]

The approach was similar as for SB (outside), except with regards to SB capex, which was included in the IOU's rate base.

4.1.6 Co-op to IOU[22]

The Project Team assumes that the IOU (or its parent company or the utility holding company that owns the IOU) buys out the members' accrued equity stake in the co-op, with a 10% premium paid to the current members.[23,24] Based on industry experience, the transaction is assumed to be done on an all-equity basis with current co-op members receiving shares in the IOU. The IOU then negotiates an agreement with the co-op and Cooperative Finance Corporation ("CFC"), the current lender to KIUC. Under the negotiated agreement, the IOU will assume the co-op's debt at an interest rate between the current rate for KIUC and market rates for the IOU. As the existing debt matures, the IOU is expected to refinance or replace it with equity or market-rate debt. The co-op's current debt can only be carried over under these negotiated terms during a transition period, assumed to be five years.[25] The acquisition premium will also be passed on to ratepayers and spread over the five-year transition period.

The rate base of the new IOU is calculated based on projections of net plant, fuel inventory, materials, and supplies inventory, and accumulated deferred income taxes using the approach described in Section 4.1.1. The operating expenses largely remain the same, except for interest expenses and income tax expenses, which are based on KIUC's rates specific to co-ops.

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[20] For Honolulu, Hawaii, and Maui counties.

[21] For Honolulu, Hawaii, and Maui counties.

[22] For Kauai county.

[23] Williams, Kevin T. "The Business Case for Co-Op Acquisitions." *Public Utilities Fortnightly – Fortnightly Magazine*, January 2005. Web.

[24] See past transaction examples in Task 1.2.2.

[25] Ibid.

4.1.7 Co-op to SB

Moving to an SB, both independent and ring-fenced within the utility, is similar in terms of treatment of SB expenses, whether the utility is a co-op or an IOU. For the SB (inside), the utility's capital structure is used to finance capital expenditures; operating expenses are passed on to consumers through the utility rates. All expenses for the SB (outside) are passed on to consumers through fees.

In the case of an SB operating alongside a co-op utility, the SB is not assumed to achieve reductions in purchased power costs for future IPP generation because co-ops are already expected to operate on the principle of maximizing cost reductions to their members.

4.2 Assumptions used in the revenue requirements model

This section provides a summary of the assumptions used to estimate the components of revenue requirements under each model for each county. These assumptions have been sourced from the utilities' public filings and reports where possible. The derivation of other assumptions is detailed further in Task 1.4.2.

4.2.1 Status Quo – HECO/MECO/HELCO

Parameter	Assumptions
Capital structure and cost of capital	The HECO Companies are capitalized with a combination of: - short-term debt - long-term debt - hybrids - preferred stock - common stock The proportion of and rate of return on the instruments were obtained from the current or most recent HECO/MECO/HELCO rate cases, including updated returns after the Tax Cuts and Jobs Act (Docket No. 2016-0328, Docket No. 2017-0150, Docket No. 2015-0170).
Effective income tax rate	For 2017, the effective state and federal income tax rates, including the effect of state income tax on the federal tax rate, were obtained from HECO/MECO/HELCO rate cases. From 2018 onwards, the analysis assumed gross federal income tax rate of 21%.
Taxes other than income taxes (revenue taxes)	The rates for public service tax, PUC fees, and franchise tax were obtained from the IOU rate cases. The payroll tax was estimated as a % of O&M labor expense.
Hawaii cost index (vs. overall United States)	The Project Team created an index to scale the levelized costs of energy forecasts from NREL to Hawaii, based on EIA – State Energy Data System 2016 (motor gasoline average price, all sectors).
Power plant life (years)	The useful service lives of power plant assets by technology (solar, wind, hydro) were assumed based on industry standards used by the Energy Information Administration ("EIA").

Plant depreciation rates	The Project Team obtained depreciation rates from rate cases for the following asset categories: - Production - T&D - General - Vehicles
Regular plant retirements	The Project Team estimated plant retirements as a percentage (%) of beginning-of-year plant balances from rate cases, based on an average of 2011-2015 data.
Annual plant O&M cost escalation	Estimated at 0.25% based on industry standards.
Annual capacity factor decrease	Estimated at 1% for renewables and 5% for thermal, to align generation by fuel type with the HECO Companies' projections in the Power Supply Improvement Plant ("PSIP") report.
Thermal plant efficiency loss	Estimated at 2% every five years, to align generation by fuel type with the HECO Companies' projections in the PSIP.

4.2.2 IOU to Co-op

Parameter	Assumptions[26]
Debt tenor	The debt tenor for co-ops was based on KIUC's audited financial statements.
Interest rate on debt	The interest rate on co-op debt was estimated in Task 1.4.2, based on KIUC's recent interest payments.
New capex debt-capital ratio	The analysis assumes that the new co-op finances its capex with 100% debt.
TIER level	TIER level is a key component of a co-op's revenue requirement, regulated by the PUC for KIUC; the analysis assumes the same TIER level applies to potential new co-ops in Hawaii.
Regular patronage capital retirement	Co-ops have discretion in returning (retiring) patronage capital to members. The analysis assumes that any revenues collected above the TIER level of 2.00 are returned to members the following year, provided the debt-to-capital ratio is below 70%.
Co-op board training expense (annual)	The annual expenses for board members' training is based on KIUC's actual expenses, provided by Beth Tokioka from KIUC via email.
Effective income tax rate	The effective state income tax rate remains unchanged. The Project Team assumes that the new co-op will be exempt from federal income taxes.

There are other potential cost reduction opportunities from a transition to a co-op model. Under the current IOU structure, MECO and HELCO are wholly-owned subsidiaries of HECO, and all three utilities are subsidiaries under Hawaiian Electric Industries ("HEI"). There are likely to be some efficiencies under a joint-ownership structure, but at the same time, overhead costs are charged to the individual utilities, as shown below in Figure 9. For instance, evaluating the net

[26] Following the November 2018 stakeholder workshops where the Project Team presented initial findings, the Team received feedback on the modeling assumptions for co-ops from stakeholders including KIUC and representatives of the Hawaii Island Electric Cooperative. This report and analysis has been updated with the revised assumptions following discussions with stakeholders.

impact of replacing the current combined IOU management structure with a co-op management on each county requires additional analysis, which is beyond the scope of this Study. For reference, the gross operating expenses in 2017 was about $1.49 billion for HECO, $302 million for HELCO, and $300 million for MECO.[27] The overhead amount in Figure 9 constituted about 7% of operating expenses for HELCO and MECO in 2017 (less than 1% for HECO). Therefore, changes in management could have a significant impact on future co-op revenue requirements.

Figure 9. IOU overhead expenses – 2017

($000s)	HEI Overhead	HECO Overhead	**Total Overhead**
HECO	4,663	-	4,663
HELCO	742	20,576	21,318
MECO	752	20,053	20,805

Source: HECO Annual Report to the PUC – 2017; HELCO Annual Report to the PUC – 2017; MECO Annual Report to the PUC – 2017.

The analysis also does not model potential disruption to utility operations from natural disasters. However, given the risks faced by the State of Hawaii in this regard, it is important to note that electric co-ops can apply for federal grants covering 75% of their eligible expenses on recovery from presidentially-declared emergency events. This assistance could provide ongoing savings to ratepayers under the co-op model. Additional details are provided in the text box below.

Federal Emergency Management Agency ("FEMA") disaster assistance for co-ops

FEMA provides grants through its Public Assistance ("PA") program to assist in recovery from major natural disasters, including to restore community infrastructure. Non-profit organizations that have federal tax-exempt status, and which operate facilities providing a critical service are eligible to apply for PA grants. Therefore, rural electric co-ops are eligible to apply for FEMA grants in case of natural disasters whereas IOUs are not.

The grants cover 75% of the eligible costs of emergency measures and permanent restoration. This is a salient point in the State of Hawaii, which is vulnerable to hurricanes, tsunamis, and volcanic eruptions. Following the 2018 eruption of Kilauea, about 935 customers lost power and more than 900 utility poles and electrical equipment were damaged or destroyed. Although the resulting costs to HELCO are not currently known, 75% of the utility's expenses for emergency response and asset repair/replacement activity could potentially have been covered through FEMA's PA grants had the utility been operated under a co-op model.

Since 2010, FEMA has awarded over $550 million to electric utilities, with nearly 100 grants larger than $1 million, and 12 grants exceeding $10 million.

Source: CFC Independent Auditors Conference, *FEMA Disaster Assistance Update*, July 2017; FEMA Public Assistance Fact Sheet; HELCO Lava Eruption Updates & Resources.

[27] *HECO Annual Report to the PUC – 2017; HELCO Annual Report to the PUC – 2017; MECO Annual Report to the PUC – 2017*

4.2.3 IOU to SB (outside)

Parameter	Assumptions
System planning and procurement expense	The system planning and procurement expenses of the HECO Companies were estimated based on the expenses of their respective planning departments, obtained from their rate cases. Additional details are in Task 1.4.2.
IOU-SB overlap	Despite the creation of a SB, the IOU is expected to retain some planning and procurement functions for internal use. The analysis assumes this overlap to be 50% (degree of SB capabilities that IOU still retains)
Rent	The Project Team estimated annual rent expenses for the SB offices based on the HECO Companies' number of staff in planning departments and average rental rates in Hawaii. Further details on the calculation can be found in Task 1.4.2.
SB Audits	The cost of an annual audit of the SB was based on estimates of the cost of an independent audit for a non-profit from the National Council of Nonprofits.
Decrease in purchased power costs	The Project Team estimated gains from increased competition based on a prior LEI study of several quantitative studies on the benefits of competition and unbundling (as detailed in Task 1.4.2), which showed efficiency gains between 3% and 14%. The analysis assumed a conservative base case of 3% gains from the increased competition.

4.2.4 IOU to SB (inside)

Parameter	Assumptions
SB capex	The capex of an SB consists of expenditure on: - Furniture & equipment - Leasehold improvements - Computers - AV equipment - Telephone system As described in more detail in Task 1.4.2, the capex estimates were based on actual capex of the Ontario Power Authority ("OPA") when it was created in 2005. Costs are adjusted to consider exchange rate, inflation, and size of the utility.
SB capex – asset life (years)	The useful life of the assets was also obtained from OPA. It informed the periodicity of recurring capex to replace the assets once their service life ended
System planning and procurement expense	See above [Section 0 – IOU to SB (outside)]
IOU-SB overlap	See above [Section 0]
Rent	See above [Section 0]
Decrease in purchased power costs	See above [Section 0]

4.2.5 KIUC

Parameter	Assumptions
Status Quo (Co-op)	
Cost of capital	The interest rate on co-op debt was estimated in Task 1.4.2, based on the average of 2013 – 2016 ratio of KIUC's interest expense to beginning-of-year long-term debt.
Debt term	The debt tenor for co-ops was based on KIUC's audited financial statements.
Debt-capital ratio	KIUC's current debt-capital ratio was calculated from its annual report to the PUC. This ratio was assumed to be the percentage of debt used to finance new capex.
TIER level	KIUC's TIER level of 2.00, according to its last rate case (Docket No. 2009-0050), was used for co-op revenue requirement calculations.
Regular patronage capital retirement	Co-ops have discretion in returning (retiring) patronage capital to members. The analysis assumes that any revenues collected above the TIER level of 2.00 are returned to members the following year, provided the debt-to-capital ratio is below 70%.
Effective income tax rate	The analysis uses the same effective state income tax rate obtained from the HECO Companies' rate cases. The Project Team assumes that KIUC continues to be exempt from federal income taxes.
Taxes other than income taxes (revenue taxes)	Revenue tax rates are the same as for IOU. [see Section 4.2.1 – Status Quo – HECO/MECO/HELCO]
Hawaii cost index (vs. the overall United States)	Same as for IOU. [see Section 4.2.1]
Power plant life (years)	Same as for IOU. [see Section 4.2.1]
Plant depreciation rates	Depreciation rates for KIUC's asset categories (Production, T&D, General, Vehicles) were taken from KIUC Depreciation Study.
Regular plant retirements (% of BoY plant balance)	The Project Team estimated plant retirements as a % of beginning-of-year plant balances KIUC's annual reports to the PUC, based on average of 2012-2016 data.
Annual plant O&M cost escalation	Same as for IOU. [see Section 3.2.2.1]
Annual capacity factor decrease	Estimated at 1% for renewables and 10% for thermal, to align generation by fuel type with KIUC's RPS goals.
Thermal plant efficiency loss	Same as for IOU. [see Section 3.2.2.1]
Co-op to IOU	
Cost of capital	The capital costs for the new IOU were obtained by averaging the rates of return of HECO, MECO, and HELCO.

Co-op to SB (outside)	
System planning and procurement expense	System planning and procurement expense assumed that KIUC is approximately half the size of MECO, based on customers and sales.
Co-op-SB overlap	Same as for IOU to SB. [see Section 0]
Rent	Based on the assumption that KIUC is approximately half the size of MECO.
SB Audits	Same as for IOU to SB. [see Section 0]
Decrease in purchased power costs	Since co-ops operate on the principle of minimizing costs to their members, the Project Team assumes that a SB will not result in additional gains from increased competition. The incentive to lower costs already exists in a co-op.
Co-op to SB (inside)	
SB capex	Same as for IOU to SB [see Section 4.2.4], with the assumption that KIUC is approximately half the size of MECO.
SB capex – asset life (years)	Same as for IOU to SB [see Section 4.2.4].
System planning and procurement expense	Same as for IOU to SB [see Section 4.2.4], with the assumption that KIUC is approximately half the size of MECO.
Co-op-SB overlap	Same as for IOU to SB [see Section 4.2.4].
Rent	Same as for IOU to SB [see Section 4.2.4], with the assumption that KIUC is approximately half the size of MECO.
Decrease in purchased power costs	See above [Co-op to SB (outside)]

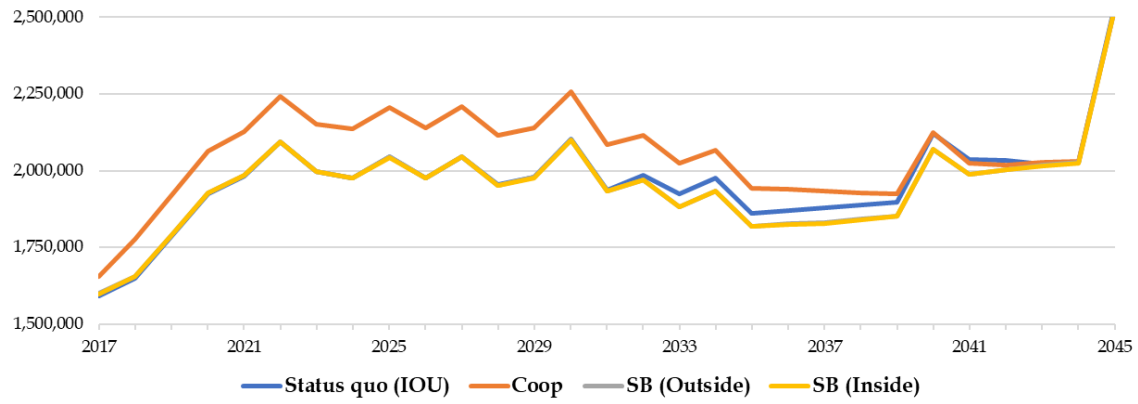
5 Revenue requirements results

This section summarizes the projections of revenue requirements under different ownership models in each county, including a discussion of the drivers of projected increases and decreases. The Project Team also conducted sensitivity analyses to evaluate the impact of changing underlying assumptions on overall projections.

5.1 HECO (Honolulu County)

The revenue requirements in Honolulu County, shown in Figure 10, are projected to increase in the short-term (2017-2022) under all ownership models. After 2022, revenue requirements in Honolulu County are projected to stabilize under the IOU and co-op models. There is a spike in 2045 due to biodiesel conversions of remaining HECO-owned generation;[28] the HECO Companies' forecasted biodiesel prices are much higher than those of fuel oil or diesel.

Figure 10. Projected Revenue Requirements for Honolulu County by Ownership Model ($000s, nominal)



Note: The line for SB (Outside) is hidden behind the SB (Inside) line.

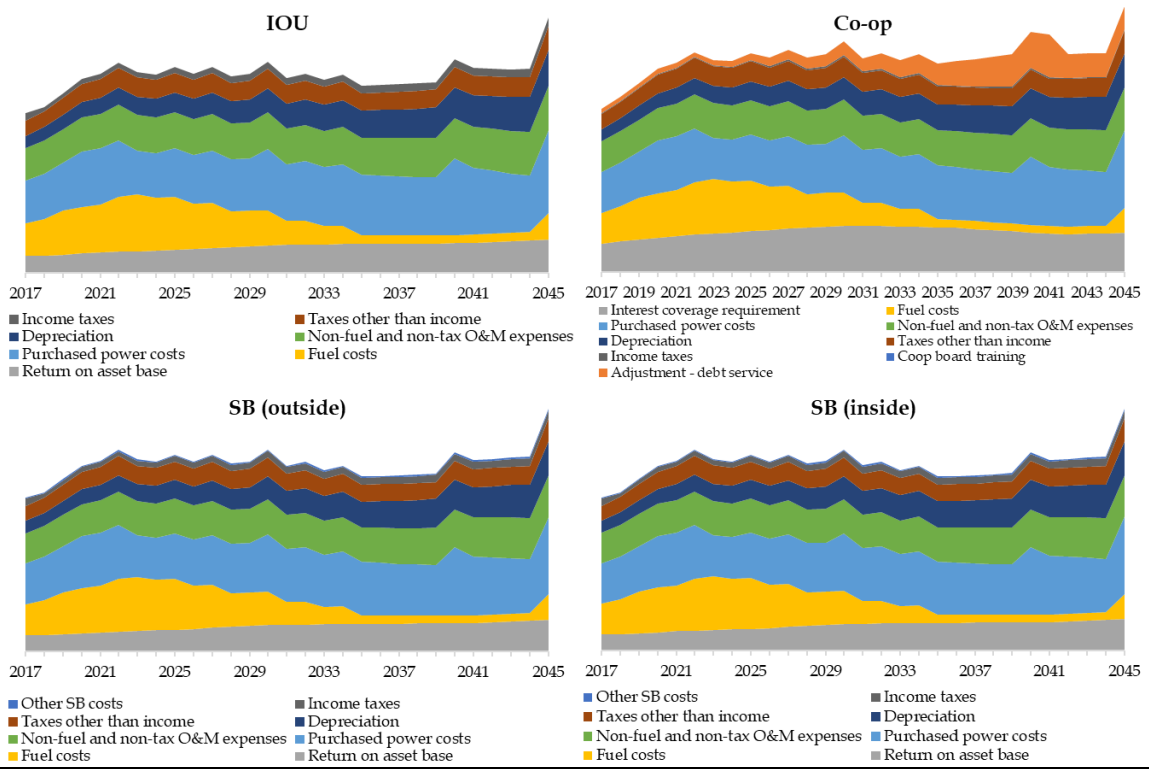
The drivers of the changes can be seen in Figure 11. The initial increase (2017 – 2022) is pushed by projections of rising fuel and purchased power costs. The anticipated increase in fuel costs for HECO's thermal plants and cost of power purchased from IPPs is based on the data provided in the PSIP, in which HECO forecasts rising fuel prices and that new IPP-owned plants come online. Revenue requirement under a co-op model is projected to be higher than the other models in this period because the co-op starts with 100% debt, which causes its interest coverage requirement under the TIER calculation to be higher initially. However, the co-op's estimated margins using these calculations are not sufficient to cover HECO's projected capex. The analysis includes an adjustment to cover debt repayment. This adjustment also results in higher forecasted revenue requirements under the co-op model.

[28] According to the PSIP report, Waiau 9 & 10, CIP CT-1 Diesel, Schofield, JBPHH, KMCBH, and the combined cycle plants will convert to biodiesel in 2045.

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Under the IOU model, fuel costs are projected to decline as HECO's current generation plants start to retire (see Figure 11). However, this is offset by a large increase in purchased power costs as new IPP-owned plants come online, especially five new 151 MW combined-cycle plants. In the co-op and two SB models, power supply expense on future IPP-owned plants is expected to be 3% lower than in the IOU model. As a result, the forecasted revenue requirement under the two SB models decline relative to the IOU model after the combined-cycle plants come online.

Figure 11. Distribution of Projected Revenue Requirements – Honolulu County



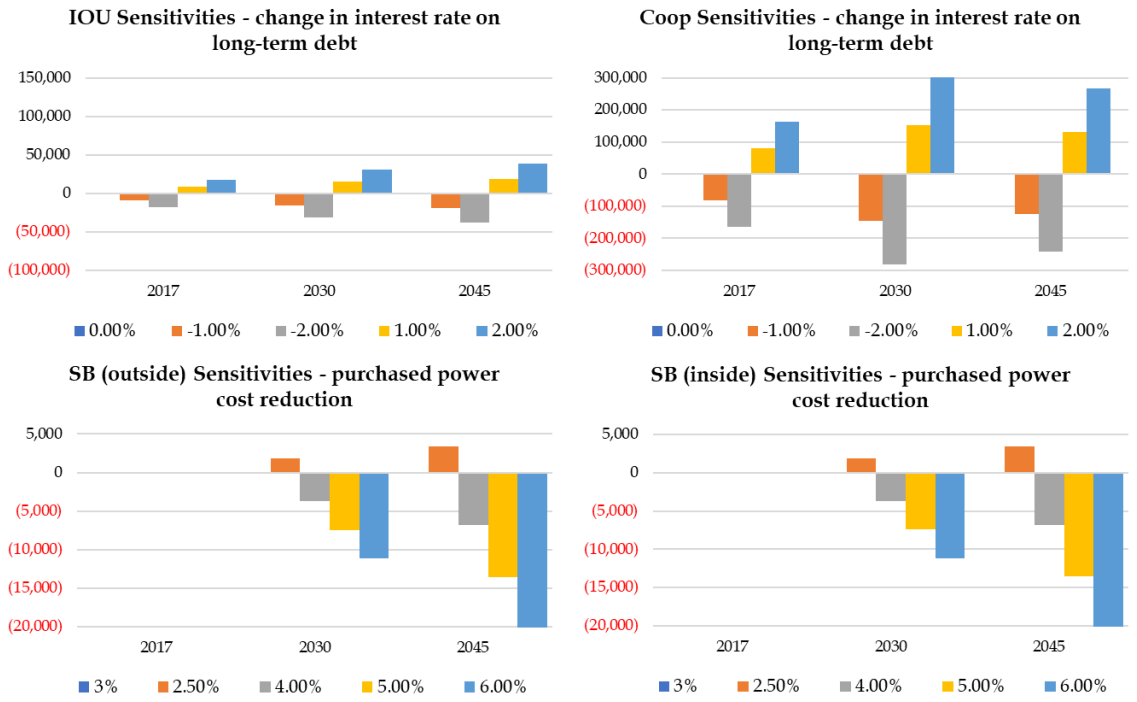
The Project Team conducted several sensitivity analyses based on key assumptions by ownership model, shown in Figure 12. Changes in the interest rate on long-term debt do not impact the IOU model as much as the co-op model. In the IOU model, a 1 percentage-point decrease interest rate on long-term debt will lower projected revenue requirements by $9 million in 2017, $16 million in 2030, and $19 million in 2045; a 2 percentage-point increase raises projected revenue requirements by $17 million in 2017, $31 million in 2030, and $38 million in 2045.

The interest rate on long-term debt is even more important under the co-op model due to the TIER based calculation, as Figure 12 shows. In the co-op model, a 1 percentage-point decrease interest rate on long-term debt will lower projected revenue requirements by $82 million in 2017, $145 million in 2030, and $124 million in 2045.

The key assumption in the SB models is the 3% reduction in purchased power costs with respect to costs for the IOU, from competition-induced efficiency gains. Although revenue requirements under the two SB models are slightly different, the impact of purchased power costs is identical, which can be seen in Figure 12. A 2.5% reduction in purchased power costs would not cover the

incremental costs associated with an SB's operations and projected revenue requirements would increase by $2 million in 2030 and $3 million in 2045 under both SB models. However, a 6% reduction would decrease projected revenue requirements by $11 million in 2030 and $20 million in 2045.

Figure 12. Sensitivity Analyses – Revenue Requirement Projections for Honolulu County



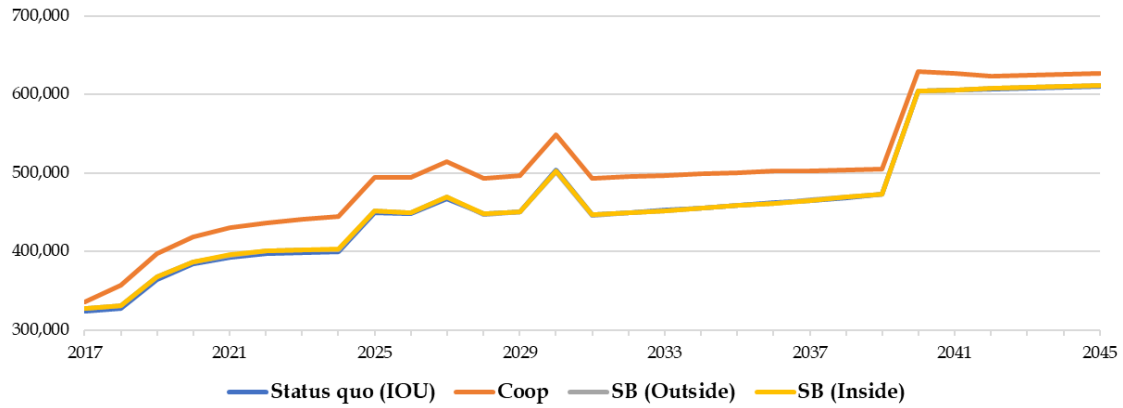
5.2 HELCO (Hawaii County)

Figure 13 shows that revenue requirements in Hawaii County are projected to increase steadily under all ownership models with a spike in 2040 due to biodiesel conversions of the current HELCO generation plants. The co-op model results in the highest projected revenue requirements throughout the analysis period.

The primary driver of the projected increase in revenue requirements is purchased power costs, as the graphics in Figure 14 show. Purchased power costs are forecasted to grow in Hawaii County due to the proposed development of two large geothermal plants and one large biomass plant. These plants are larger and more expensive on a $/MWh basis than solar and wind plants.[29] Projected revenue requirements are higher under the co-op model throughout the forecast horizon due to the adjustment for capex and debt repayment.

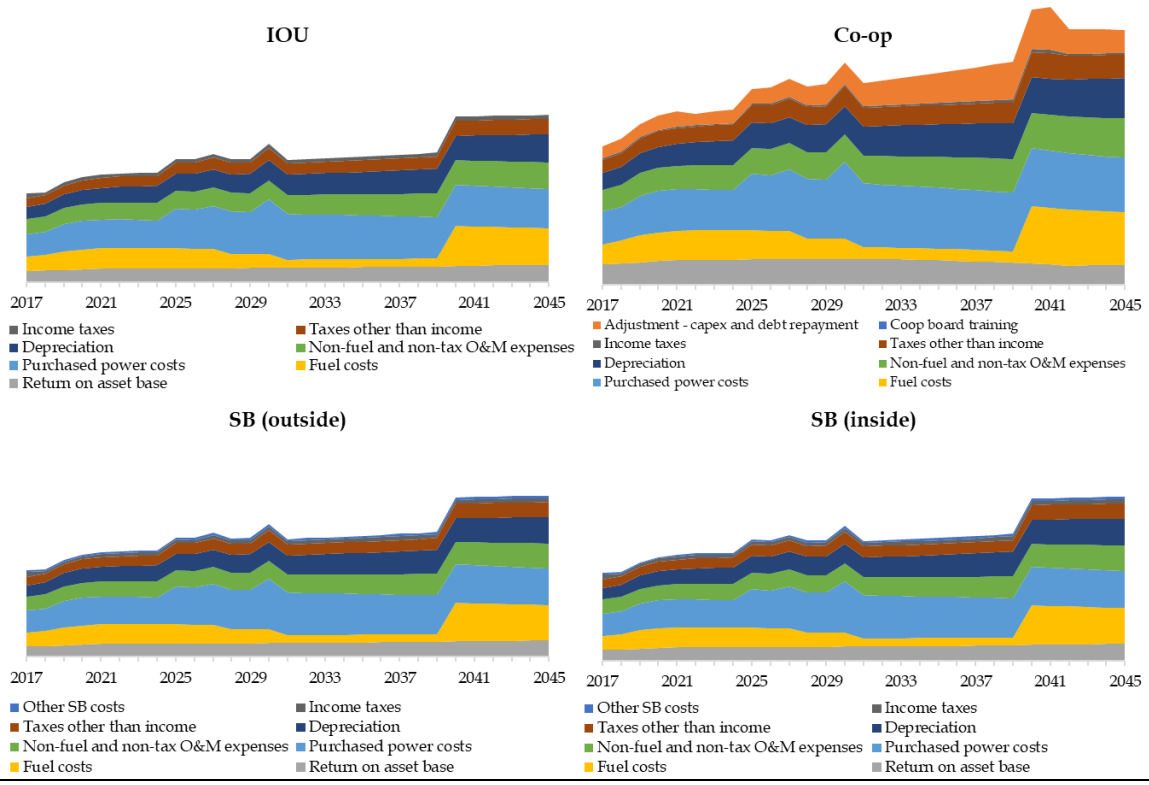
[29] NREL. *2017 Annual Technology Baseline.*

Figure 13. Projected Revenue Requirements for Hawaii County by Ownership Model ($000s, nominal)



Note: lines for IOU and SB (Outsides) are behind that of SB (Inside)

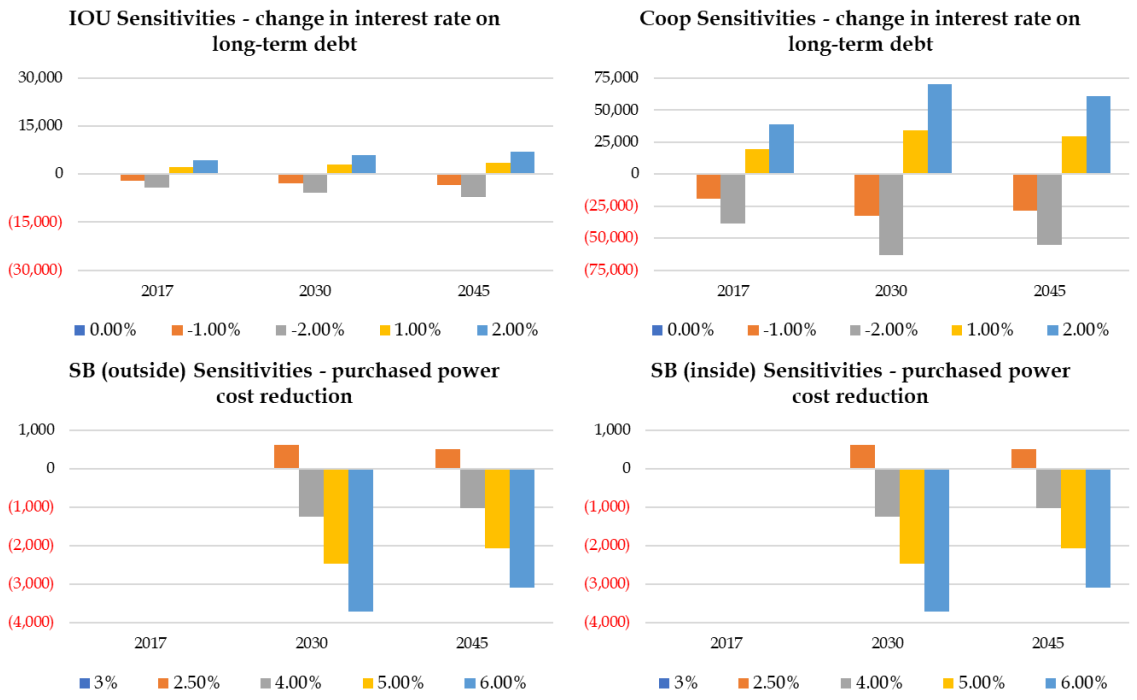
Figure 14. Distribution of Projected Revenue Requirements – Hawaii County



The results of the sensitivity analyses in Figure 15 show the impact of varying key assumptions by ownership model. In the IOU model, a 1 percentage-point decrease interest rate on long-term debt will lower projected revenue requirements by $2 million in 2017, $3 million in 2030, and $4 million in 2045; a 2 percentage-point increase raises projected revenue requirements by $4 million in 2017, $6 million in 2030, and $7 million in 2045. In the co-op model, however, a 1 percentage-point decrease interest rate on long-term debt will lower projected revenue requirements by $19 million in 2017, $33 million in 2030, and $28 million in 2045.

A 2.5% reduction in purchased power costs would not cover the incremental costs associated with an SB's operations, increasing projected revenue requirements by $0.6 million in 2030 and $0.5 million in 2045 under both SB models. However, a 6% reduction would decrease projected revenue requirements by $4 million in 2030 and $3 million in 2045.

Figure 15. Sensitivity Analyses – Revenue Requirement Projections for Hawaii County



5.3 MECO (Maui County)

Figure 16 shows that revenue requirements in Maui County are projected to increase steadily under all ownership models in the short-term (2017-2022). After 2022, revenue requirements are projected to stabilize, with spikes in 2030 and 2040 due to biodiesel conversions. Revenue requirements are projected to be higher under the co-op model initially. However, the projected revenue requirements are largely similar under all ownership models in Maui County.

The graphs in Figure 17 show the drivers of change in revenue requirements. The projected near-term increase in revenue requirements is driven primarily by power supply costs – fuel costs and purchased power costs are both projected to increase, due to rising fuel prices and large capacity additions of wind and solar in 2020. The projection of higher initial revenue requirements under the co-op model is attributable to interest coverage requirement and adjustment for capex and debt repayment.

Figure 16. Projected Revenue Requirements for Maui County by Ownership Model ($000s, nominal)

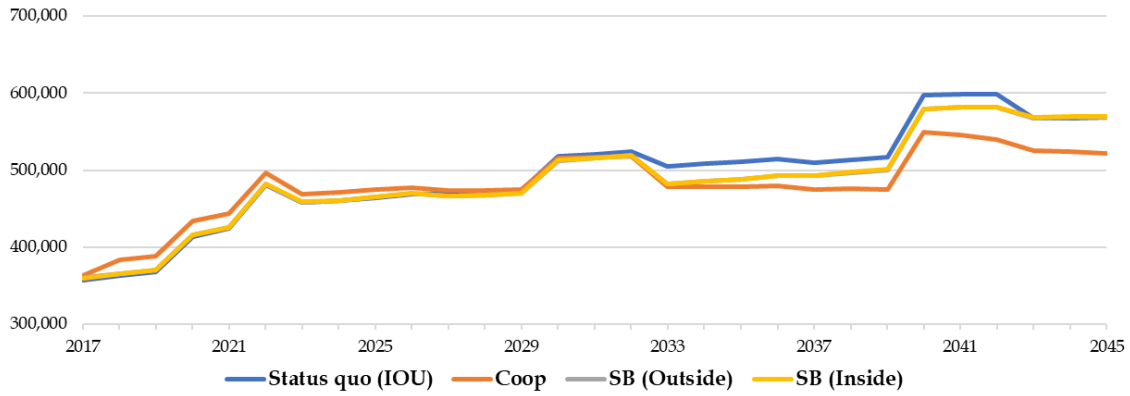
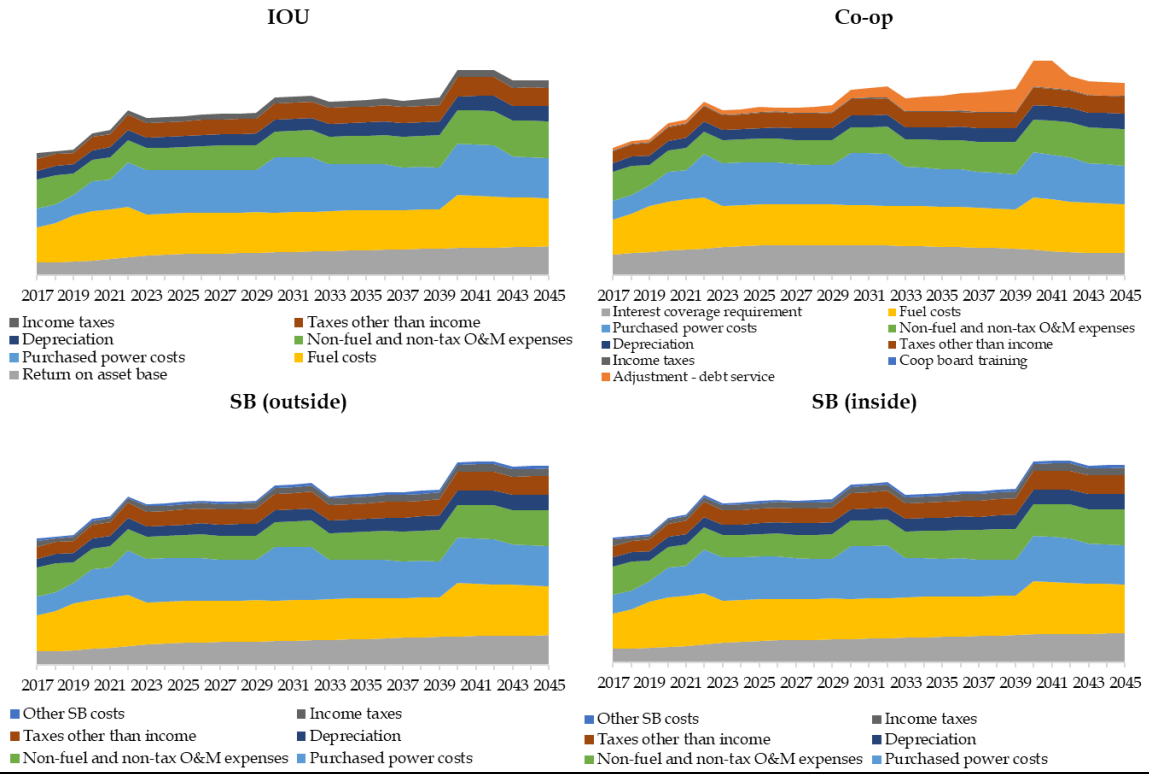


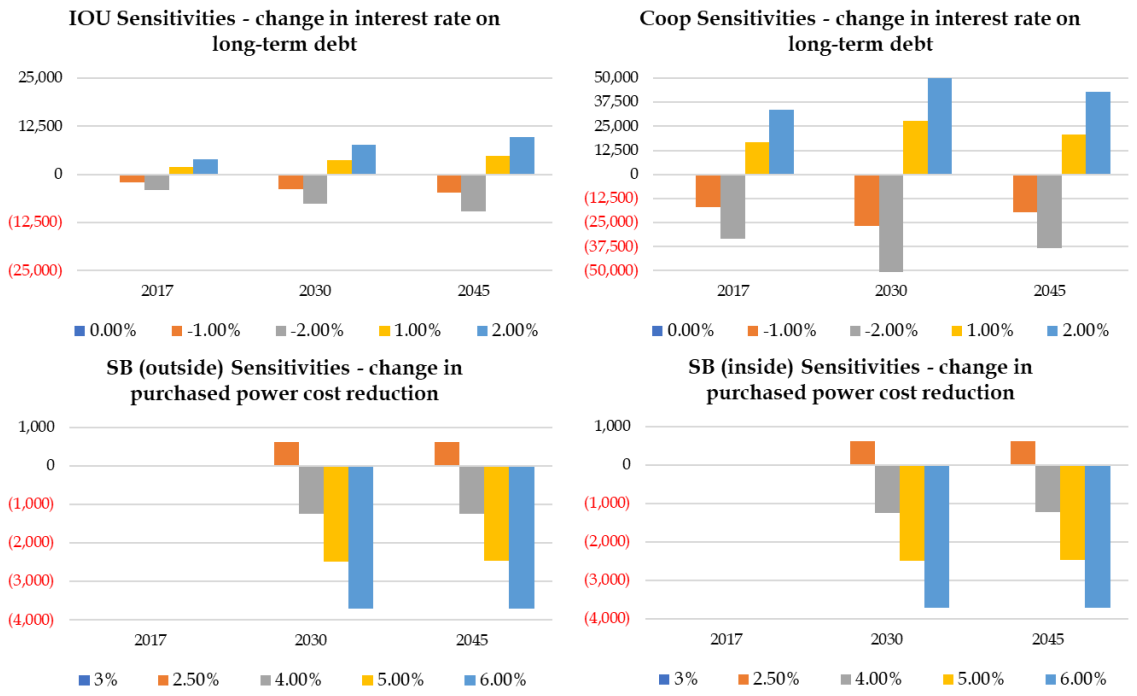
Figure 17. Distribution of Projected Revenue Requirements – Maui County



The results of the sensitivity analyses for Maui County in Figure 18 show the impact of varying key assumptions by ownership model. In the IOU model, a 1 percentage-point decrease in interest rate on long-term debt will lower the projected revenue requirements by $2 million in 2017, $4 million in 2030, and $5 million in 2045; a 2 percentage-point increase raises projected revenue requirements by $4 million in 2017, $8 million in 2030, and $10 million in 2045. In the co-op model, however, a 1 percentage-point decline in interest rate on long-term debt will decrease the projected revenue requirements by $17 million in 2017, $27 million in 2030, and $20 million in 2045.

A 2.5% reduction in purchased power costs would not cover the incremental costs associated with an SB's operations, increasing projected revenue requirements by $0.6 million in 2030 and 2045 under both SB models. However, a 6% reduction would decrease projected revenue requirements by $4 million in both years.

Figure 18. Sensitivity Analyses – Revenue Requirement Projections for Maui County



5.4 KIUC (Kauai County)

The revenue requirements in Kauai County are projected to increase under all ownership models in the short-term (2017-2020), as shown in Figure 19. Then, revenue requirements are forecasted to stabilize before growing steadily again – after 2025 under the IOU model and after 2029 under other ownership models.

The projected near-term increase in revenue requirements is driven largely by projected increases in purchased power costs as new capacity comes online, as shown in Figure 20. The differences between IOU and other models in Kauai County are also evident in Figure 20. Unlike the other counties with an incumbent IOU, the SB models operate with a co-op in Kauai County. Since KIUC has already achieved a 65% debt-capital ratio, the interest coverage requirements are not as onerous for the three cooperative-based models.[30] The projected increase in required return on asset base under the IOU model more than offsets the interest coverage requirement and adjustment to cover capex and debt repayment.

[30] Kauai Island Utility Cooperative. *2016 Annual Report to the PUC.* March 2017.

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Figure 19. Projected Revenue Requirements for Kauai County by Ownership Model ($000s, nominal)

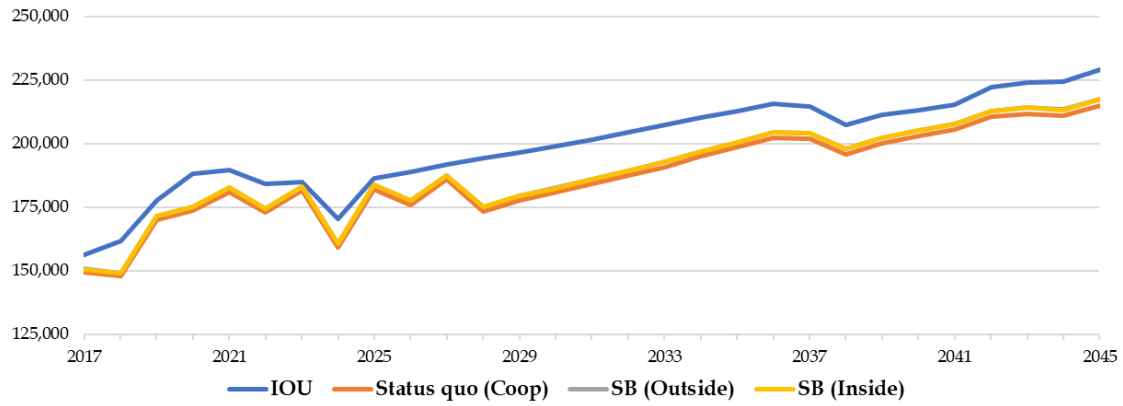
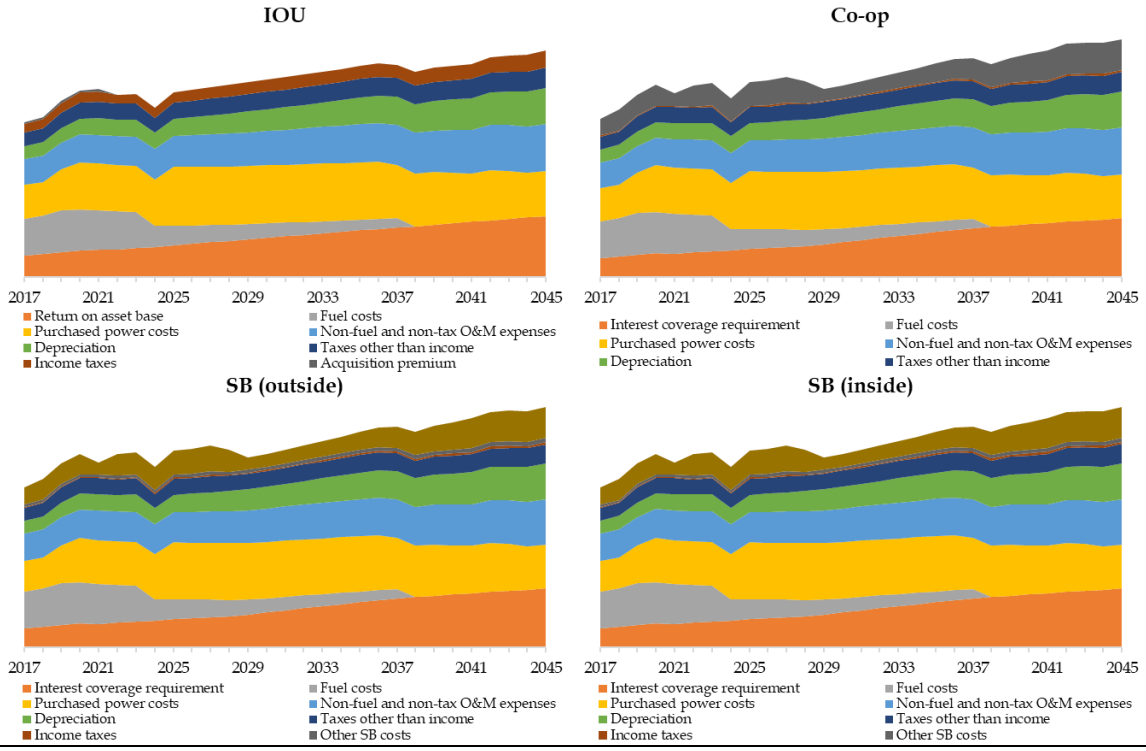


Figure 20. Distribution of Projected Revenue Requirements – Kauai County

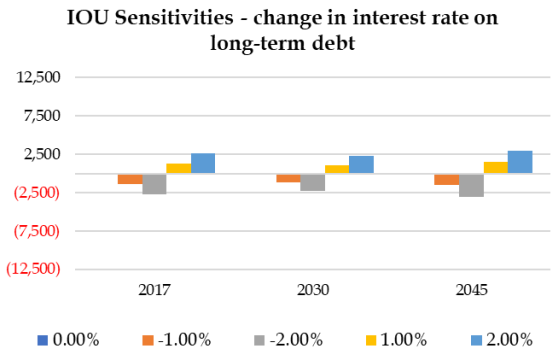


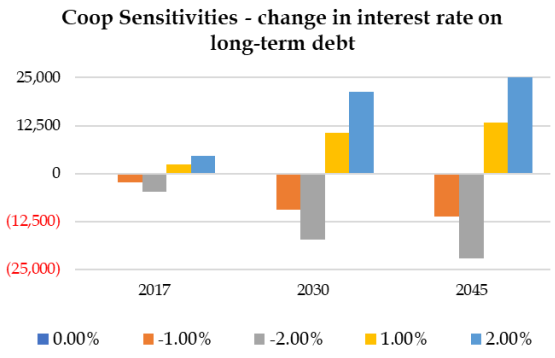
A slightly different set of sensitivity analyses were conducted Kauai County to account for the differences in starting from a co-op model. A 2.5% increase in purchased power costs instead of the assumed 3% will lower projected revenue requirements under the IOU model by $0.2 million in 2030 and 2045. However, a 6% increase would increase projected revenue requirements by over $1 million in both years.

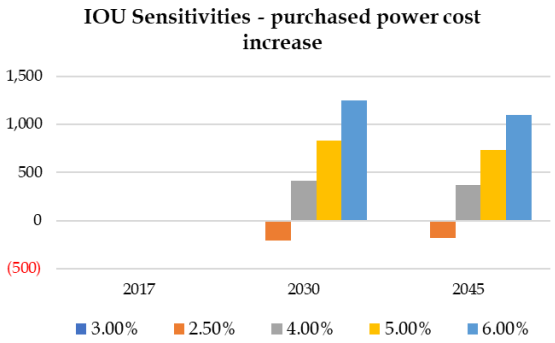
In the IOU model, a 1 percentage-point decrease in interest rate on long-term debt will lower the projected revenue requirements by $1.3 million in 2017, $1.1 million in 2030, and $1.5 million in

2045; a 2 percentage-point increase raises forecasted revenue requirements by $2.6 million in 2017, $2.3 million in 2030, and $3.0 million in 2045. In the co-op model, however, a 1 percentage-point decrease in interest rate on long-term debt will lower the projected revenue requirements by $2.3 million in 2017, $9.3 million in 2030, and $11.1 million in 2045.

Figure 21. Sensitivity Analyses – Revenue Requirement Projections for Kauai County







6 Appendix A: Scope of work to which this deliverable responds

1.6.1 Overview of the differences in how revenue requirement is calculated under each ownership model. CONTRACTOR shall provide an overview of the differences in how the revenue requirement is calculated under each ownership model.

DELIVERABLE FOR TASK 1.6.1. CONTRACTOR shall provide its conclusions and all work related to an overview of the differences in how the revenue requirement is calculated under each ownership model, including drivers and how the general formula for revenue requirement would be altered. CONTRACTOR shall provide an MS Word document, with supporting documents. CONTRACTOR shall submit deliverable for TASK 1.6.1 to the STATE for approval.

1.6.3 Estimated revenue requirements under each ownership model through 2045; graphic comparing results. CONTRACTOR shall provide the expected annual revenue requirement under each ownership model through 2045, including the identification of all major cost elements.

DELIVERABLE FOR TASK 1.6.3. CONTRACTOR shall provide its conclusions and all work related to developing an expected annual revenue requirement under each ownership model. CONTRACTOR shall use the data that is publicly available, through HECO and KIUC annual and regulatory filings, to develop an estimate of costs and information for developing current estimates for the major costs in a revenue requirement model. CONTRACTOR shall assume that there is not a different regulatory model in place. Assumptions, such as tax treatment, and cost of capital requirements, shall be altered to assess the impact that different ownership models have on the revenue requirement. CONTRACTOR shall provide an MS Excel file, which shall detail the estimated revenue requirement through 2045 under each of the ownership models. The file shall include graphics that compare the results for the three ownership models. CONTRACTOR shall submit deliverable for TASK 1.6.3 to the STATE for approval.

7 Appendix B: Assumptions used in the model

7.1 IOU (status quo)

Parameter	Assumptions	Source
Cost of capital	**HECO** Short-term debt – 1.75% Long-term debt – 5.19% Hybrids – 7.19% Preferred stock – 5.37% Common stock – 10.60% WACC – 8.28% **MECO** Short-term debt – 2.00% Long-term debt – 4.59% Hybrids – 7.16% Preferred stock – 8.15% Common stock – 10.60% WACC – 8.05% **HELCO** Short-term debt – 1.50% Long-term debt – 5.40% Hybrids – 7.21% Preferred stock – 8.18% Common stock – 10.60% WACC – 8.44%	HECO/MECO/HELCO rate cases (Docket No. 2016-0328, Docket No. 2017-0150, Docket No. 2015-0170)
Effective income tax rate	**2017** Federal – 32.895% State – 6.015% **2018 onwards** Federal – 18.895% State – 6.015%	HECO/MECO/HELCO rate cases (effect of state income tax on federal tax assumed to remain at -2.105% even after corporate taxes are lowered to 21% from 35%)
Taxes other than income taxes (revenue taxes)	Public Service Tax – 5.885% PUC Fees – 0.500% Franchise Tax – 2.500% Payroll Tax – 7.221%	HECO/MECO/HELCO rate cases (payroll tax expense as a % of O&M labor expense)
Inflation rate	2%	Industry standards
Hawaii cost index (vs overall United States)	1.32	EIA – State Energy Data System 2016 (motor gasoline average price, all sectors)
Power plant life (years)	Solar PV – 25 Wind – 30 Battery – 10 Hydro – 50+	Industry standards
Plant depreciation rates	**HECO** Production – 1.952%	HECO/MECO/HELCO rate cases

	T&D – 3.324% General – 2.450% Vehicles – 6.130% **MECO** Production – 2.709% T&D – 1.863% General – 5.117% Vehicles – 4.046% **HELCO** Production – 2.519% T&D – 3.650% General – 5.782% Vehicles – 6.721%	
Regular plant retirements (% of BoY plant balance)	**HECO** Production – 0.764% T&D – 0.697% General – 0.234% Vehicles – 5.387% **MECO** Production – 1.224% T&D – 0.316% General – 4.719% Vehicles – 9.475% **HELCO** Production – 0.300% T&D – 0.607% General – 2.317% Vehicles – 6.190%	HECO rate case (Docket No. 2016-0328) - an average of 2011-2015 data
Annual plant O&M cost escalation	0.25%	Industry standards
Annual capacity factor decrease	Renewables – 1% Thermal – 5%	To match HECO's projections of generation output by fuel type in the PSIP.
Thermal plant efficiency loss	2% every five years	To match HECO's projections of generation output from thermal plants in the PSIP.

7.2 IOU to Co-op

Parameter	Assumptions	Source
Debt tenor	25 years	KIUC Audited Financial Statement 2003
Interest rate on debt	4.10%	Task 1.4.2, Figure 24
Target debt-capital ratio	70%	KIUC rate case

		(Docket No. 2009-0050)
TIER level	2.00	KIUC rate case (Docket No. 2009-0050)
Regular patronage capital retirement	The analysis assumes that any revenues collected above the TIER level of 2.00 are returned to members the following year, provided the debt-to-capital ratio is below 70%.	Stakeholder feedback
Co-op board training expense (annual)	$78,394	Task 1.4.2, Figure 29

7.3 IOU to SB (outside)

Parameter	Assumptions	Source
System planning and procurement expense	HECO – $9,738,000 MECO – $4,929,000 HELCO – $5,599,000	Task 1.4.2, Figure 33
IOU-SB overlap	50% (degree of SB capabilities that IOU retains)	Task 1.4.2, Section 5.2.2.1
Rent	HECO – $279,000 MECO – $46,000 HELCO – $81,000	Task 1.4.2, Figure 34
SB Audits	$15,000	Task 1.4.2, Section 5.2.2.2
Decrease in purchased power costs	3%	Task 1.4.2, Section 5.2.2.3

7.4 IOU to SB (inside)

Parameter	Assumptions	Source
SB capex	**HECO** Furniture & equipment – $1,050,000 Leasehold improvements – $1,305,000 Computers – $621,000 AV equipment – $122,000 Telephone system – $44,000 **MECO** Furniture & equipment – $172,000 Leasehold improvements – $214,000 Computers – $102,000 AV equipment – $20,000 Telephone system – $7,000 **HELCO** Furniture & equipment – $305,000 Leasehold improvements – $379,000 Computers – $180,000 AV equipment – $35,000	Task 1.4.2, Figure 31

	Telephone system – $33,000	
SB capex – asset life (years)	**HECO** Furniture & equipment – 10 Leasehold improvements – 40 Computers – 3 AV equipment – 10 Telephone system – 5 **MECO** Furniture & equipment – 10 Leasehold improvements – 40 Computers – 3 AV equipment – 10 Telephone system – 5 **HELCO** Furniture & equipment – 10 Leasehold improvements – 40 Computers – 3 AV equipment – 10 Telephone system – 5	Task 1.4.2, Figure 31
System planning and procurement expense	HECO – $8,717,000 MECO – $4,709,000 HELCO – $5,473,000	Task 1.4.2, Figure 37
IOU-SB overlap	50% (degree of SB capabilities that IOU retains)	Task 1.4.2, Section 5.2.2.1
Rent	HECO – $279,000 MECO – $46,000 HELCO – $81,000	Task 1.4.2, Figure 34
Decrease in purchased power costs	3%	Task 1.4.2, Section 5.2.2.3

7.5 KIUC

Parameter	Assumptions	Source
Status Quo (Co-op)		
Cost of capital	Long-term debt – 4.10% (average of 2013 – 2016 ratio of interest expense to beginning-of-year long-term debt)	KIUC Annual Report to PUC 2016
Debt term	25 years	Task 1.4.2, Figure 24
Debt-capital ratio	Current – 65.3% Target – 65.0%	KIUC Annual Report to PUC 2016
TIER level	2.00	KIUC rate case (Docket No. 2009-0050)
Regular patronage capital retirement	The analysis assumes that any revenues collected above the TIER level of 2.00 are returned to members the following year, provided the debt-to-capital ratio is below 70%.	Stakeholder feedback
Effective income tax rate	Federal – 0% State – 6.015%	HECO/MECO/HELCO rate cases
Taxes other than income taxes (revenue taxes)	Public Service Tax – 5.885% PUC Fees – 0.500% Franchise Tax – 2.500%	KIUC Annual Report to PUC 2016
Inflation rate	2%	
Hawaii cost index (vs. the overall United States)	1.32	EIA – State Energy Data System 2016 (motor gasoline average price, all sectors)
Capex financing	65% – debt 35% – equity (net margins)	
Power plant life (years)	Solar PV – 25 Wind – 30 Battery – 10 Hydro – 50+	
Plant depreciation rates	Production – 2.990% T&D – 2.729% General – 3.170% Vehicles – 6.400%	KIUC Depreciation Study
Regular plant retirements (% of BoY plant balance)	Production – 1.367% T&D – 1.278% General – 2.445% Vehicles – 2.857%	KIUC Annual Reports to PUC 2012 – 2016
Annual plant O&M cost escalation	0.25%	
Annual capacity factor decrease	Renewables – 1% Thermal – 10%	For thermal plants, adjusted to meet KIUC RPS goals

Thermal plant efficiency loss	2% every 5 years	
Co-op to IOU		
Cost of capital	Long-term debt – 5.06% WACC – 8.26%	HECO/MECO/HELCO average
Co-op to SB (outside)		
System planning and procurement expense	$2,465,000	assume KIUC is half the size of MECO
Co-op-SB overlap	50% (degree of SB capabilities that co-op retains)	Task 1.4.2, Section 5.2.2.1
Rent	$23,000	assume KIUC is half the size of MECO
SB Audits	$15,000	Task 1.4.2, Section 5.2.2.2
Decrease in purchased power costs	0% (co-ops have the incentive to minimize costs to members)	USDA Rural Development *Understanding Cooperatives: Cooperative Business Principles*
Co-op to SB (inside)		
SB capex	Furniture & equipment – $86,000 Leasehold improvements – $107,000 Computers – $51,000 AV equipment – $10,000 Telephone system – $4,000	Task 1.4.2, Figure 31 assume KIUC is half the size of MECO
SB capex – asset life (years)	Furniture & equipment – 10 Leasehold improvements – 40 Computers – 3 AV equipment – 10 Telephone system – 5	Task 1.4.2, Figure 31
System planning and procurement expense	$2,355,000	assume KIUC is half the size of MECO
Co-op-SB overlap	50% (degree of SB capabilities that co-op retains)	Task 1.4.2, Section 5.2.2.1
Rent	$23,000	assume KIUC is half the size of MECO
Decrease in purchased power costs	0% (co-ops have the incentive to minimize costs to members)	USDA Rural Development *Understanding Cooperatives: Cooperative Business Principles*

8 Appendix C: List of works consulted

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General assessment of cash flows under each ownership model

working paper prepared by London Economics International LLC for the State of Hawaii with support from Meister Consultants Group

April 25, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals; this document is one of several working papers associated with that engagement. This paper summarizes the modeling approach and results of the analysis of cash flows under each ownership model. The accompanying MS Excel workbooks called "Cash Flow Analysis" contain the financial models by each county. The projections of cash flows were based on the Project Team's forecasts of revenue requirements submitted under Task 1.6.3. Therefore, it evaluates, on a high level, the anticipated financial health of the utilities under various ownership models using cash flows as a metric. The Project Team also analyzed the different approaches to raising capital and their impact on cash flows: fixed vs. flexible capital structure approaches for an Investor-Owned Utility ("IOU") as well as with vs. without an adjustment on the capital expenditure ("capex") in revenue requirements for a cooperative ('co-op"). For all the ownership models, the fixed capital structure approach resulted in higher projected cash flows initially, whereas the flexible capital structure approach resulted in larger cash balances in the long run. But in Maui County, projected cash balances were negative under the IOU model, with both fixed and flexible capital structure approaches. The co-op model with capex adjustment was forecast to generate the highest cash balances, but with an excessive burden on ratepayers. Without this adjustment, cash balances under the co-op model were projected to be negative in Kauai County but positive elsewhere. In terms of cash flows, the two Single Buyer ("SB") models were very similar to each other as well as the underlying status quo utility, except in Honolulu County.

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List of acronyms

CAPM	Capital Asset Pricing Model
CFC	Cooperative Finance Corporation
CIAC	Contributions in Aid of Construction
DBEDT	Hawaii Department of Business, Economic Development, and Tourism
EIA	Energy Information Administration
EBIT	Earnings Before Interest and Taxes
FCFF	Free Cash Flow to the Firm
GAPP	Generally Accepted Accounting Principles
HECO	Hawaiian Electric Company
HELCO	Hawaii Electric Light Company
HoldCo	Holding Company
IC	Invested Capital
IFRS	International Financial Reporting Standards
IOU	Investor-Owned Utility
IPP	Independent Power Producer
IRS	Internal Revenue Service
ITC	Investment Tax Credit
kWh	Kilowatt-hour
KIUC	Kauai Island Utility Cooperative
LCOE	Levelized Cost of Electricity
LEI	London Economics International LLC
MECO	Maui Electric Company
NARUC	National Association of Regulatory Utility Commissioners
NOPAT	Net Operating Profits After Tax
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
PBR	Performance-based Ratemaking
PPA	Power Purchase Agreement
PSIP	Power Supply Improvement Plan
PUC	Hawaii Public Utilities Commission
RAB	Regulatory Asset Base
REC	Regional Electricity Company
ROE	Return on Equity
ROIC	Return on Invested Capital
RPS	Renewable Portfolio Standards
RUS	Rural Utilities Service
SB	Single Buyer
T&D	Transmission and Distribution
TIER	Times Interest Earned Ratio
USDA	United States Department of Agriculture
WACC	Weighted Average Cost of Capital
YTM	Yield to Maturity

1 Executive summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which responds to Tasks 1.6.2 in the project scope of work, provides a county-level overview of the cash flows between 2017 and 2045 under four different ownership models: Investor-Owned Utility ("IOU"), cooperative ("co-op"), an independent Single Buyer ("SB"), and a ring-fenced SB within the utility. The memo describes the rationale for a cash flow analysis, which is based on the revenue requirement forecasts from Task 1.6.3. The analysis in this document and the accompanying MS Excel workbooks can support assessments of the utilities' financial health under each ownership model.

The utilities' planned capital expenditure ("capex"), particularly those of the HECO Companies, is high relative to their forecast operating cash. Consequently, the utilities are expected to regularly raise additional cash. For IOUs, the Project Team analyzed two approaches to raising capital: a fixed capital structure scenario vs. a flexible capital structure scenario. The fixed capital structure scenario forces the IOUs to maintain the capital structure from their last rate cases throughout the forecast horizon. The flexible capital structure scenario only raises new debt for planned capex and does not raise or retire equity throughout the forecast horizon.

The base scenario modeled for co-ops from the revenue requirement analyses under Task 1.6.3 included an adjustment to cover planned capex in that year in addition to the initial revenue requirement calculated using the Times Interest Earned Ratio ("TIER") approach, described in more detail in Task 1.4.2. The alternate scenario for co-ops excludes this capex adjustment and also substantially lowers revenue requirements under the co-op model.

The co-op model with adjustment for capex is projected to achieve the highest Free Cash Flow to the Firm ("FCFF") in Honolulu, Hawaii, and Maui counties after switching from the current. Without the adjustment, the co-op model's forecast FCFF is comparable to those of the SB models in Hawaii and Honolulu counties, and the lowest in Maui and Kauai counties. Conversely, in Kauai County where the current utility is a co-op, the IOU model is predicted to result in higher FCFF after 2028. Figure 4 shows the projected FCFF for all the counties.

The analyses found little difference in terms of cash flows between the two SB models, as well as between the SB models and the status quo ownership model. The exception was Honolulu County, where the IOU model includes new generation plants under utility ownership. Under IOU model, the fixed capital structure approach was expected to generate higher cash flows initially; after the 2020s, the flexible approach was projected to generate more cash with growth in operating revenue and decline in investment needs.

The results indicate that the co-op model with capex adjustment generates the highest cash flows and balances across all counties. However, this is achieved through higher revenue requirements and places an undue burden on ratepayers because the projected growth of cash balances using the capex adjustment is 14% per year over the forecast horizon in all four counties. Without

including the capex adjustment, the co-op model is expected to result in positive and stable (low growth) balances in counties with an incumbent IOU. However, this approach results in negative cash balances on Kauai and Maui Counties and indicates a potential financial risk.

In Maui County, the projections indicate negative cash balances under IOU and SB models for most years in the forecast horizon; the negative balances are expected to persist for longer with the flexible capital approach. Holders of equity in the utilities are forecast to gain most from the IOU or SB model with a flexible capital structure approach. The fixed capital structure approach dilutes equity returns, creating a risk of falling stock prices and increasing costs of equity. A comparative summary of projected results by ownership model (with both SB models grouped together) is provided in the table below. The various scenarios under each ownership model to which the results apply are specified within. Variation between scenarios for SB models follow similar trends and levels as variation between those scenarios under IOU or co-op ownership models.

IOU	Co-op	SB
Free Cash Flow to Firm		
very little difference (<1%) in FCFF between fixed vs. flexible capital scenarios negative through 2019 in Hawaii and Maui Counties and through 2020 in Honolulu County lower than co-op (capex adjustment) in Kauai County	capex adjustment scenario results in highest FCFF in all counties negative FCFF in Kauai County for no capex adjustment scenario in more than half of the years of the forecast horizon vs. status quo IOU, no capex adjustment approach lowers FCFF in Maui County and increases it in Honolulu and Hawaii counties (until 2033 and 2039 respectively)	very little difference between independent and ring-fenced SB models lower FCFF vs. status quo IOU in Kauai County, very little difference with status quo co-op
Cash balance – impact of capital structure or capex adjustment		
mostly positive cash balances except in Maui County under both IOU scenarios cash balances higher initially (up to 2030s) under fixed capital structure scenario than flexible capital structure scenario from co-op to IOU in Kauai County, cash balances are higher using a target capital structure approach	negative cash balances in Kauai County for no capex adjustment scenario very high growth in cash balances in all counties using capex adjustment scenario - ~14% per year over the forecast horizon	generally similar to the underlying utility substantially lower than status quo IOU in Honolulu County due planned plant development under utility ownership in the IOU model
Returns on equity		

highest using flexible capital structure scenario (no target in Kauai County)	no difference between w/ vs. w/o capex adjustment scenarios for members	no difference vs. status quo co-op in Kauai County slightly higher vs. status quo IOU in Hawaii and Maui counties higher vs. status quo IOU in Honolulu County until 2025; significantly lower thereafter
Financial risk		
negative cash balance in Maui County, under both fixed and flexible capital structure scenarios fixed capital structure scenario dilutes equity returns, potentially lowering stock prices and increasing the cost of equity	negative cash balances in Kauai County, using no capex adjustment scenario	similar to the underlying utility (but worse in Maui County)

The Project Team anticipates that the utilities and the PUC will face key decisions over raising capital regardless of the ownership model adopted. The combination of debt and equity raised may have a significant impact on the financial viability of the utility. Alternately, the utilities may judge it prudent to stagger their capex plans differently or revise their dividend payouts.

For instance, MECO can address the projected negative cash balance by not paying dividends or raising additional capital. In the fixed capital structure approach, the utility can avoid negative cash balances by withholding dividends on common stock in 2018 and 2019. Alternately, it can raise another $25 million in capital in 2018. In the flexible capital structure approach, it would have to withhold dividends between 2017 and 2020 or raise $75 million in 2018.

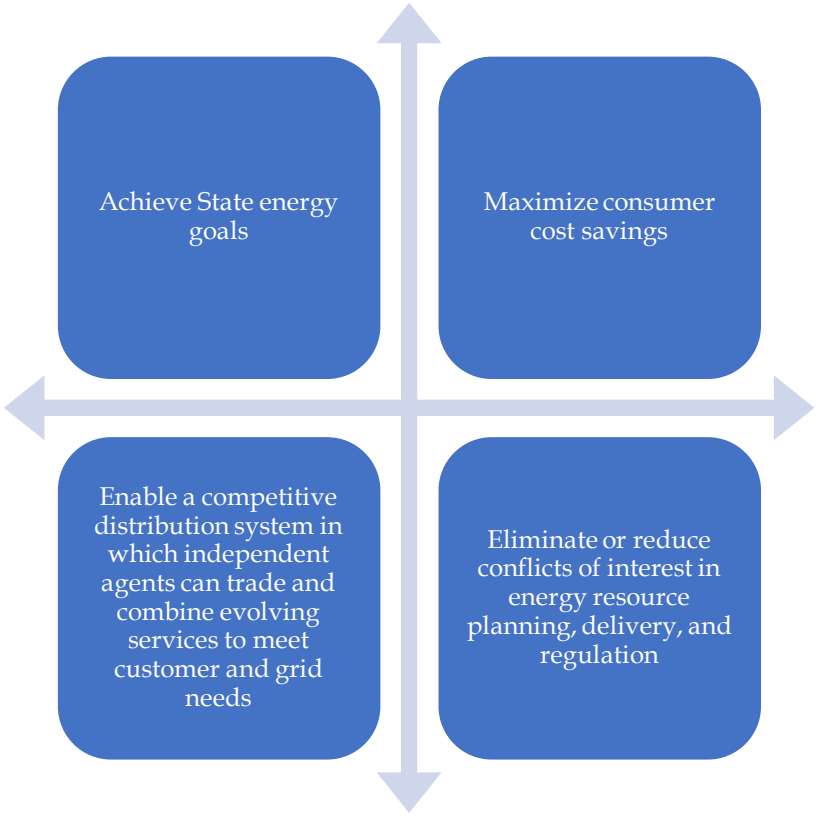
Similarly, KIUC can maintain positive cash balances by including the capex adjustment only when its investment needs are high. The utility can address the persistently negative cash balances in Figure 17 by including capex adjustment in its revenue requirements for just three years – 2017, 2018, and 2027. In addition, this would lower the projected revenue requirements by $841 million over the forecast horizon, or a Net Present Value ("NPV") of $275 million at 8% discount rate.

2 Introduction and scope

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission on a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[1] was contracted to perform this study.[2]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[3] listed in Figure 1.

Figure 1. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

The study will help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition,

[1] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[2] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[3] House Bill No. 1700 Relating to the State Budget.

it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[4]

This deliverable is responsive to Task 1.6.2 in the project scope of work. It evaluates cash flows out to 2045 for the four utilities in the State of Hawaii under four ownership models: Investor-Owned Utility ("IOU"), cooperative ("coop"), independent Single Buyer ("SB"), and a ring-fenced SB within the utility. The analyses are based on revenue requirements projections in Tasks 1.6.1 and 1.6.3. It discusses the principles of cash flow analyses, including an overview of accrual vs. cash basis of accounting. Based on this discussion, the Project Team developed cash flow models based on projected revenue requirements for each ownership model. The analysis was conducted at a county level and is included in the accompanying MS Excel workbooks.

[4] Hawaii Contract No. 65595. Scope of Services.

3 Cash flows

A firm, in this case, an electric utility, requires cash when it invests in new plants, compensates its employees, or pays interest to the bank and issues dividends to the shareholders. It receives cash when its customers pay their electric bills, or it issues new debt or equity. It is important to keep track of the incoming and outgoing cash. The utility's cash flow can be quite different from its net income, due to:

- the income statement uses the accrual method of accounting, which means that revenues and expenses are recognized as they are incurred rather than when the cash is received or paid out. A utility makes a sale when a customer uses electricity but only receives the cash for it when the customer pays for that period. This is described in more detail in Section 3.3. The statement of cash flows shows the firm's cash inflows and outflows from operations as well as from its investments and financing activities;

- the income statement does not recognize capital expenditures as expenses in the year that the capital goods are paid for. Instead, it spreads those expenses over time in the form of an annual deduction for depreciation.

3.1 What is cash flow analysis?

The statement of cash flows details a company's cash inflows and outflows from its operations as well as from its investment and financing activities. Cash flow analysis is the evaluation of these inflows and outflows, to illustrate how the utility is generating and using its money and where it is using it. As mentioned previously, there are three components of a statement of cash flows, which are:

i. Cash flows from **operating activities** show the cash generated from a utility's regular business activities and transactions. Operating activities only include revenues received and payments made in the current period. Operating cash flows are calculated by adjusting the net income from the income statement for changes in current assets and liabilities.

ii. Cash flows from **investing activities** include cash collected from the sale of or cash spent on purchasing a new long-term asset. A long-term asset is expected to remain in service beyond the current period. It reflects a utility's investment in itself because these investments support the utility's business operations over multiple periods. Investing cash flows are calculated by adding up the changes in long-term asset accounts.

iii. Cash flows from **financing activities** reflect how a utility finances or pays for its operations through long-term debt or equity. Therefore, financing cash flows are the sum of cash collected from issuing long-term debt (taking loans) and equity and the cash used to repay loans and pay dividends on its equity.

3.2 Benefits of evaluating cash flows

A utility's statement of cash flows can indicate how profitable its operations actually are. A consistently negative cash flow before financing (sum of cash from operating and investing activities) is an indication that the utility is not generating enough cash to cover its investment needs. For an electric utility, this may arise if rates are not high enough to cover operating costs as well as capex in grid infrastructure. Therefore, the utility needs to raise capital more frequently. However, the underlying weakness of its operations will ultimately lower stock prices and make it more difficult to raise the necessary capital.

Free Cash Flow to the Firm ("FCFF") is another measure of a company's performance. It is the cash available to investors, both debt, and equity after the firm has paid for all of its operating expenses and made necessary investments in current assets such as inventory and long-term assets such as utility plants. As it represents the sum available to investors, it is regarded as a very strong indicator of a utility's financial health. FCFF describes a firm's cash flows available to investors, whereas the statement of cash flows describes the current state of the cash account *after* meeting obligations to investors and if necessary, raising additional capital.

The Project Team calculated both FCFF and annual cash flows and balances. However, the analyses in this report focus primarily on cash flows to evaluate how the utilities' cash balances are impacted by financing decisions such as raising debt vs. equity capital and disbursement of dividends.

3.3 Cash vs. accrual basis

Accrual accounting is the standard approach used when accounting for revenues and expenses. It involves accounting for revenues and expenses as these are earned and incurred, regardless of when actual cash transfers occur. Therefore, if a business receives a good or service on January 1, but only makes payment for it on January 31 (i.e., the supplier extends a line of credit to the business), the accrual accounting approach will record the expense as occurring on January 1. This expense will be recorded in the accounts payable line item, found in the current liabilities section of the balance sheet. The same applies to recording revenues earned, which is documented in the accounts receivable item, found in the current assets section of the balance sheet.[5]

The accrual accounting methodology creates a more accurate picture of a company's current financial condition, as it ensures activities that occur during the reporting period are reflected in that period's financial statements. This allows businesses to manage their current resources better and plan more effectively for the future.[6]

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[5] "How does accrual accounting differ from cash basis accounting?" *Investopedia.* <https://www.investopedia.com/ask/answers/09/accrual-accounting.asp>

[6] "Accrual accounting." *Investopedia.* <https://www.investopedia.com/terms/a/accrualaccounting.asp>

	Accrual Accounting	Cash Basis Accounting
Overarching approach	Revenues and expenses are recorded as they are earned and incurred, regardless of when cash transfers occur.	Revenues and expenses are recorded on the date when cash or payment exchanges hands.
Operations and maintenance expense	Following the overarching approach, operations and maintenance ("O&M") expenses are recorded in the period in which they are incurred.	Operating costs are adjusted to align with the accrual-based approach, by (i) adding beginning prepaid expenses, (ii) deducting ending prepaid expenses, (iii) adding ending accrued expenses, and (iv) deducting beginning accrued expenses. Maintenance costs are expensed in the period in which they are paid for.
Taxes	Businesses are obligated to pay taxes on their reported profit, even if the underlying revenues have yet to be transferred at the time of filing.	Expenses are deducted in the tax year in which the business pays them, while income is taxable in the tax year in which the revenue is received.
Financing capital improvements	Capital improvements are capitalized or expensed over the life of the asset.	Like the accrual accounting approach, capital improvements are capitalized if the improvements result in the asset's betterment, restoration, or adaptation to a new or different use.
Depreciation	The cost of a long-lived asset is expensed gradually over the course of the asset's useful life. The depreciation schedule is determined based on (i) how long the asset's useful life is, and (ii) the depreciation base, or the total amount to be depreciated.	Although depreciation is a non-cash expense, the costs of large capital assets are allocated over their useful lives in the same way as the accrual accounting methodology, as required by the Internal Revenue Code.
Return on invested capital	Return on invested capital ("ROIC") is calculated by dividing net operating profits after tax ("NOPAT") by invested capital ("IC"). Earnings before interest and taxes ("EBIT"), an accrual accounting line item, must be converted to align with NOPAT, by multiplying EBIT by 1 minus the tax rate.	ROIC is calculated in the same way, by diving NOPAT by IC. Since NOPAT is a cash basis line item, no adjustments need to be made under this approach.

While this approach provides an accurate picture of how much cash a business currently has on hand, it distorts financial performance. Cash basis accounting is especially misleading for longer-term projects where revenue is only earned upon completion, as substantial costs are recorded throughout the project, thus exaggerating losses during that period, and significant revenues are recorded upon the project's completion, exaggerating gains.[7] For this reason, financial statements

[7] "Cash basis." *Investopedia.* <https://www.investopedia.com/terms/c/cashbasis.asp>

created using the cash basis approach are not accepted under Generally Accepted Accounting Principles ("GAAP") or International Financial Reporting Standards ("IFRS").[8]

On the other hand, the cash basis accounting approach accounts for revenues and expenses on the date when cash or payment exchanges hands, and is used mostly by small, private companies. In the example above, the cash basis approach would record the expense as occurring on January 31, the date the payment was transferred from the business to the supplier. The same methodology applies when recording revenues earned.[9]

3.3.1 Operations and maintenance expense

According to the National Association of Regulatory Utility Commissioners ("NARUC"), operating expenses are "*those costs incurred to provide ongoing service to customers*," while maintenance expenses are "*those costs incurred to keep the utility's systems running properly and make repairs as necessary*."[10]

Operating costs under the cash basis accounting approach are recorded under a single line item, which needs to be adjusted in order to align with the accrual-based equivalent, operating expenses. To convert the cash-based operating costs to accrual-based operating expenses, the following adjustments need to be made: (i) add beginning prepaid expenses; (ii) deduct ending prepaid expenses; (iii) add ending accrued expenses; and (iv) deduct beginning accrued expenses.[11]

In terms of maintenance costs, these are expensed in the period they are incurred under the accrual accounting approach, compared to being expensed in the period they are paid for under the cash basis approach.[12]

3.3.2 Taxes

When a firm first files taxes with the IRS, it can elect to adopt either the accrual or cash basis accounting approach. In order to switch methodologies for subsequent tax filings, the business must obtain approval from the IRS by completing Form 3115, Application for Change in

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[8] "The modified cash basis of accounting." *Accounting Tools.* <https://www.accountingtools.com/articles/what-is-the-modified-cash-basis-of-accounting.html>

[9] "How does accrual accounting differ from cash basis accounting?" *Investopedia.* <https://www.investopedia.com/ask/answers/09/accrual-accounting.asp>

[10] National Association of Regulatory Utility Commissioners. Regulatory Authority Competences in Monitoring the Bookkeeping of the Regulated Companies. May 17, 2013.

[11] Wahlen, James, Jefferson Jones and Donald Pagach. "Intermediate Accounting: Reporting and Analysis." South-Western Cengage Learning. p. 3-34.

[12] "How to account for repairs & maintenance under GAAP." *Chron.* <http://smallbusiness.chron.com/account-repairs-maintenance-under-gaap-36482.html>

Accounting Method.[13] Regardless of the accounting method utilized, the firm will pay the same amount of taxes, with the only difference being when these taxes are paid.

Under the accrual method, firms are obligated to pay taxes on their reported profit, even if the underlying revenues have yet to be transferred at the time of filing.[14] Therefore, firms that do not receive payments immediately are often required to pay taxes on cash that has not yet entered their accounts. This can be troublesome for businesses that are short on cash and is therefore preferred by companies with large accounts payable balances (i.e., goods and services they have purchased on credit), as it allows them to deduct these expenses before having paid for them.[15]

Under the cash basis method, expenses are deducted in the tax year in which the business pays them. Similarly, income is taxable in the tax year in which the revenue is actually received. Therefore, the cash basis method is preferred among firms that carry large accounts receivable balances, where there is a delay between when the business provides a service and when the customer pays for it. Using the cash basis method ensures the firm can defer when it must pay taxes on income until the period when payment has been received.[16]

3.3.3 Financial capital improvements

Capital improvements include expenses that increase the value or extend the useful life of an asset, excluding expenses that are part of routine maintenance.[17] Under accrual accounting, capital improvements are capitalized or expensed over the life of the asset, opposed to being expensed in the period in which the cost is incurred.[18] Under capitalization, the capital improvement cost is depreciated according to the methods discussed in Section 3.3.4 below.

3.3.4 Financial capital improvements

In order to comply with accrual accounting's fundamental "matching principle," where expenses are matched to the revenues that were generated by those expenses, the cost of a long-lived asset is expensed gradually over the course of the asset's useful life. Determining the amount to be depreciated each year, also called the depreciation schedule, involves considering two elements:

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[13] "Difference between accrual & cash basis tax returns." *Chron.* <http://smallbusiness.chron.com/difference-between-accrual-cash-basis-tax-returns-25144.html>

[14] "Cash vs. accrual and why accounting matters for taxes." *Open Forum.* <https://www.americanexpress.com/us/small-business/openforum/articles/cash-vs-accrual-and-why-accounting-matters-for-taxes-1/>

[15] "Cash vs. accrual basis for your business's taxes." *Quantify Group.* <https://thequantifygroup.com/cash-vs-accrual-basis-businesss-taxes>

[16] Ibid.

[17] "GAAP rules for capital expenditures." *Chron.* <http://smallbusiness.chron.com/gaap-rules-capital-expenditures-77592.html>

[18] "Capitalization." *Investopedia.* <https://www.investopedia.com/terms/c/capitalization.asp>

(i) how long the asset's useful life is; and (ii) the depreciation base, or the total amount to be depreciated, often calculated as the asset's cost minus its estimated salvage value. From these two elements, a depreciation schedule is conceived. The schedule may take many forms, such as the straight-line method, where an equal amount is depreciated annually; or the declining-balance method, where the amount to be depreciated each year is calculated as a percentage of the asset's book value for that year.[19]

Although depreciation is a non-cash expense, the cash basis accounting approach allocates the cost of large capital assets over its useful life in the same way as the accrual accounting methodology, as required by the Internal Revenue Code. For example, businesses using the cash basis accounting approach may apply the straight-line or the declining balance depreciation methods to large, long-lived assets. Smaller assets do not need to be depreciated and are expensed at cost at the time the payment is made.[20]

3.4 Treatment of cash flows in the financial model

The Project Team's model treats all cash flows on an accrual accounting basis for all ownership models. Revenue requirement and its components are projected on an annual basis, with each year's estimated expenses and revenues recorded in the same year. As the models project out to 2045, using a cash basis methodology instead is not expected to have a significant impact on cash flows and revenue requirements. For each year, accrued expenses and revenues would include items paid for in either prior years or future years. For example, the revenues recorded for 2025 using the accrual basis includes all the kWh sales in that year. On a cash basis, revenues for 2025 may include payments received from customers paying their electric bills for November and December of 2024 but not of 2025. Over a long-time horizon, this difference can be expected to have an approximately net zero impact.

1) O&M expenses for each year are estimated based on the utility's assets and sales for that year.

2) Tax expenses are recorded based on the utility's revenues and taxable income for that year. In practice, a utility's actual tax payments will likely not align with its tax liabilities for that period. However, the model treats tax expenses on an accrual basis because it assigns all income and expenses to the year that they are accrued. For example, all the utility's revenues and costs associated with its operations during 2018 are recorded under 2018, regardless of the year that the utility receives its revenues or pays its expenses. As a result, its tax liability for 2018 is based on its recorded revenues and expenses from that year.

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[19] "How is depreciation handled in accrual accounting." *Chron.* <http://smallbusiness.chron.com/depreciation-handled-accrual-accounting-43791.html>

[20] Texas A&M: AgriLife Extension. *Financial Management: Cash vs. Accrual Accounting.*

3) Financing for capital improvements is raised each year based on the planned capex for that year.

4) Depreciation expense is recorded for each year based on the book value of assets at the beginning of that year and the depreciation rates of various categories of assets.

5) Return on invested capital is estimated for each year using assumptions about cost of capital.

3.4.1 Comparison of cash flows between ownership models

The treatment of the five categories of cash flows described above can vary slightly by ownership model. For instance, a utility's depreciation expense under an SB model is different based on whether the SB is independent or ring-fenced. Likewise, IOUs and co-ops have different options available to raise financing for capex, which impacts cash flows. The table below summarizes similarities and differences among ownership models in terms of how the five broad categories of cash flows are treated.

IOU	Co-op	SB (outside)	SB(inside)
O&M expenses			
Consists of power supply, other labor and non-labor O&M, depreciation, and tax expense.	Generally like the IOU Tax expense is lower for co-op vs. IOU due to exemption from federal income tax. Also includes co-op board training expense.	Utility retains O&M expenses for general operations, except for expenses related to planning and power procurement	Similar to SB (outside), although some synergies exist because SB is part of the utility
Taxes			
Revenue taxes. Federal income taxes. State income taxes.	No federal income taxes.	SB O&M expenses change the taxable income for the utility.	SB O&M expenses change the taxable income for the utility.
Financing capital improvements			
Debt and equity at market rates.	Low-cost debt from coop-specific sources. Equity raised from customer-members as patronage capital.	SB-specific capex in the SB-fee charged to the utility.	SB-specific capex financed with utility's financing options
Depreciation			
Based on the original cost of the asset and its useful life.	Based on the original cost of the asset and its useful life.	SB-assets do not affect utility depreciation expense.	SB-assets are included in utility depreciation expense.
Return on invested capital			
Debt repayment at utility terms. Equity investors receive allowed return on rate base.	Debt repayment at coop-specific terms.	SB (outside) mode ldoes not impact ROIC relative to underlying utility (either IOU or co-op).	With co-op, no impact on ROIC. With IOU, equity investors receive incremental returns on SB assets.

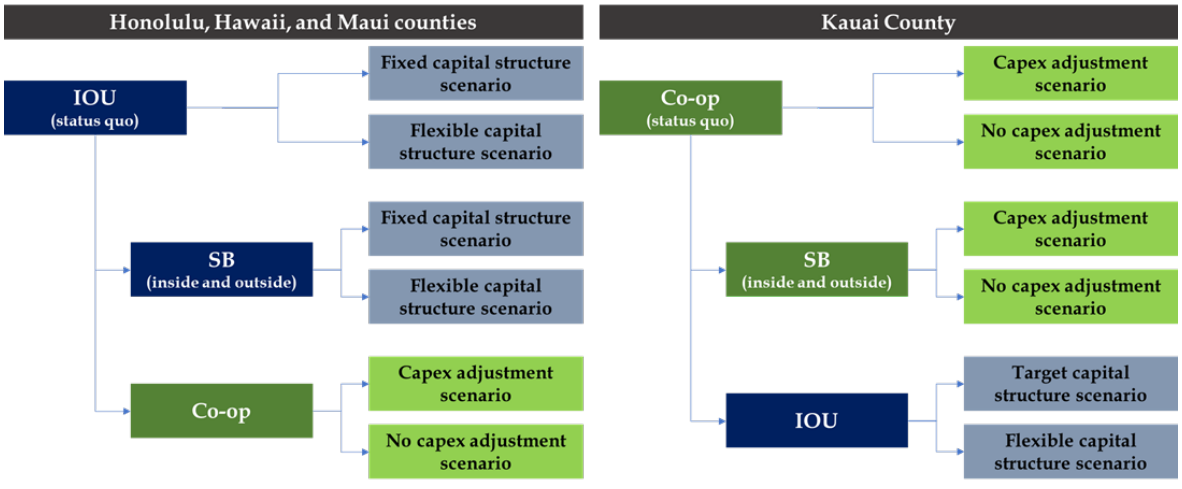
4 Modeling approach

This section details the approach used to analyze cash flows under different ownership models and scenarios. The Project Team used the following methodology to generated forecasts of cash flows:

1. Income statements were developed and used to estimate FCFF for each county and ownership model based on the revenue requirement projections from Task 1.6.3.
2. Then, cash flows from investment and operating activities were calculated:
    a. Cash flows from operating activities were based on net income from the income statement and other components from existing revenue requirement projections such as depreciation expense, deferred income taxes, and changes in inventory, regulatory assets and liabilities, allowance for funds used during construction, and working capital.
    b. Cash flows from investing activities were based on the utilities' capex plans, allowance for funds used during construction, and contributions in aid of construction used in Task 1.6.3.
3. The Project Team analyzed the different financing scenarios based on whether the incumbent utility in the county is an IOU or a co-op and will be detailed further below. The scenarios resulted in two cash flows from financing activities for each county and ownership model.
4. Cash flows from operations, investments, and financing were added to obtain total annual cash flows.
5. The total cash flow for each year was added to a cash balance account to keep track of the cumulative cash balances.

The following diagram illustrates the scenarios analyzed by ownership model for each county. These different scenarios are discussed in detail in the succeeding subsections.

Figure 2. Scenarios by ownership model and county



4.1 Approach used for Honolulu, Hawaii, and Maui counties

The status quo utility in Honolulu, Hawaii, and Maui counties is an IOU. As discussed in Section 3.1, a utility generates cash inflows from its operations. An IOU uses a portion of this cash inflow to invest in assets that support its operations; if there is a shortfall, it can generate additional cash through financing by issuing new debt or equity.

For this analysis, the Project Team considers the investing needs as a pre-determined input, based on the HECO Companies' projections of planned capex. Likewise, there is limited room to alter the cash from operations, which are derived from the revenue requirement forecasts from Task 1.6.3. Revenue requirement itself is largely based on the HECO Companies' existing assets, planned capex, and operating costs. However, the utility can raise the additional financing for planned capex through different combinations of new debt and/or equity issuance. Although debt is a cheaper source of capital than equity, the utility must also account for the impact on its capital structure. A higher leverage ratio could increase its risk profile result in higher borrowing costs.

The Project Team evaluated two different scenarios for an IOU to raise capital: (i) maintain existing PUC-approved capital structure (or the "fixed capital structure scenario"), and (ii) allow some flexibility on its capital structure (or the "flexible capital structure scenario.")

The fixed capital structure scenario forces the IOUs to maintain the capital structure from their last rate cases throughout the forecast horizon. Capital structure is impacted by new debt and equity raised, debt repayments, and equity retirements through share buybacks. Under this scenario, the IOU raises new equity when it raises new debt, sized to maintain the capital structure. Likewise, when debt repayments bring down the total debt level, it retires an amount of shares that helps to maintain the capital structure.

The flexible capital structure scenario only raises new debt for planned capex and does not raise or retire equity throughout the forecast horizon. Revenue requirement under the IOU model was not discernably impacted by fixed vs. flexible capital structure scenarios; the Project Team assumes identical revenue requirements, and consequently net income, under both scenarios for IOUs.

Both SB models in Honolulu, Hawaii, and Maui counties were analyzed under fixed vs. flexible capital structure scenarios since the underlying utility remains an IOU.

4.2 Approach used for Kauai County

For co-ops, the two scenarios of raising the capital are: (i) Adjusting the revenue requirement to cover planned capex in that year (or the "capex adjustment scenario"), and (ii) not including this adjustment in revenue requirements calculated using the Times Interest Earned Ratio ("TIER") approach described in more detail in Task 1.4.2 (or the "no capex adjustment scenario.")

The revenue requirement analyses under Task 1.6.3 for co-ops were calculated using the capex adjustment scenario. Since the capex adjustment is included in revenue requirements, the co-op

effectively raises additional capital from equity, since it is owned by its ratepaying members. The no capex adjustment scenario for co-ops substantially lowers revenue requirements.

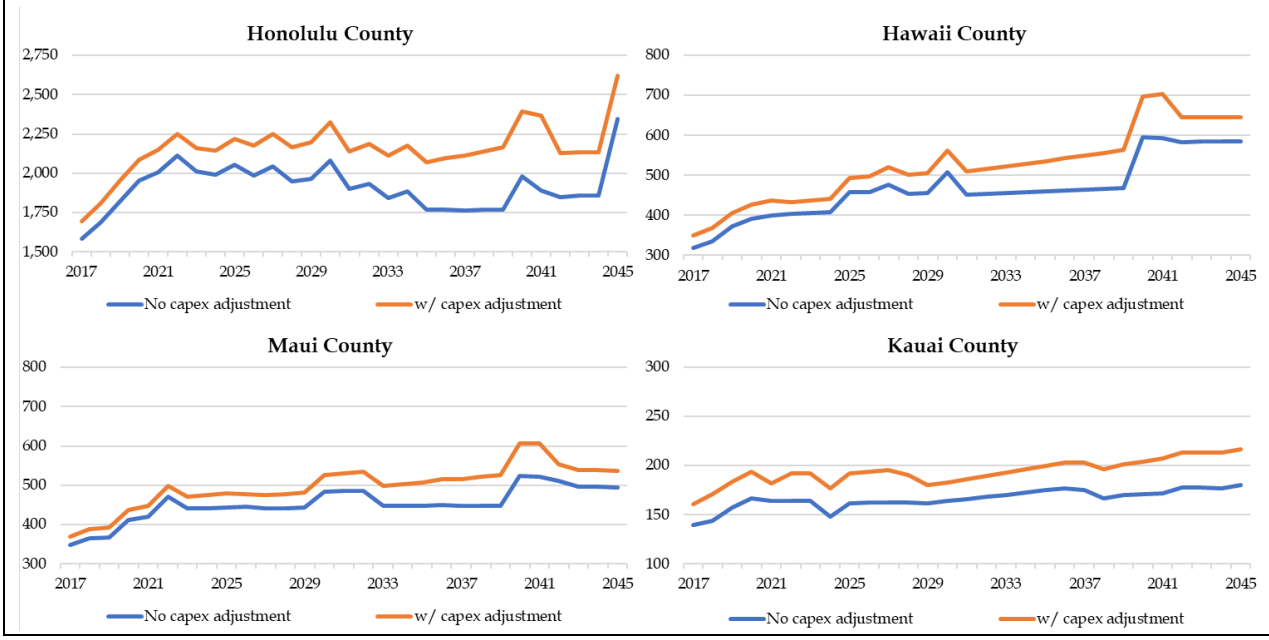
In Kauai County, the incumbent utility is an electric co-op. Consequently, the two SB models are also based on the utility structured as a co-op and are analyzed under both capex adjustment and no capex adjustment scenarios.

Two scenarios were also analyzed for the transition from a co-op to an IOU model in Kauai County: (i) replace KIUC's current low-cost debt entirely with market rate debt after a transition period (also called the "flexible capital structure scenario" similar to the IOU model), and (ii) replace KIUC's debt with a combination of debt and equity to achieve a target equity-capital ratio (or the "target capital structure scenario"). The latter scenario would align the capital structure of the hypothetical IOU in Kauai County more closely with those of the HECO Companies.

4.3 Impact of the scenarios on the revenue requirements

For IOU and IOU-based SB models, the impact of fixed vs. flexible capital structure scenarios on revenue requirement forecasts in Task 1.6.3 is not significant (<1%) because the analysis assumes that borrowing costs remain constant regardless of capital structure. On the other hand, the no capex adjustment scenario for the co-op model would substantially lower revenue requirement projections as shown in Figure 3. The cash flow analyses in the following sections can shed additional light on whether the utility can maintain financial health under the alternate scenario.

Figure 3. Forecast revenue requirements for co-op model by county and scenario ($000s, nominal)

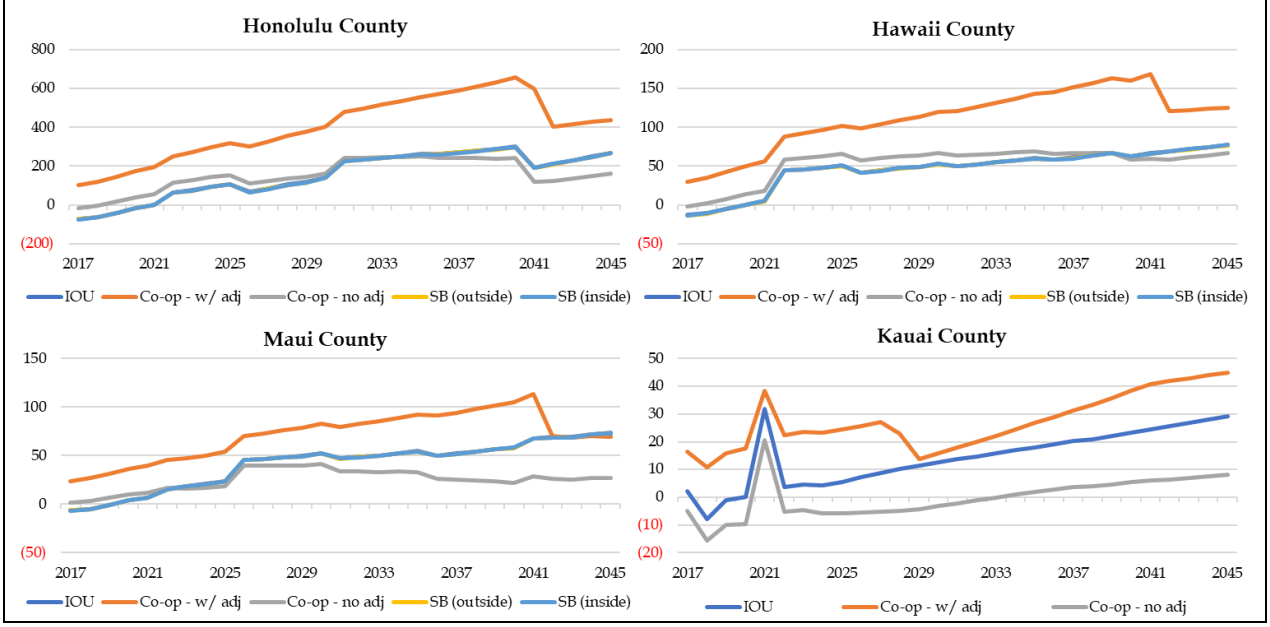


5 Cash flows by ownership model

The co-op model under capex adjustment scenario is projected to achieve the highest FCFF in Honolulu, Hawaii, and Maui counties after switching from the current IOU model, as well as in Kauai County. The significantly higher revenue requirements forecast under the capex adjustment scenario (see Figure 3 and Task 1.6.3) result in higher projections for net income and therefore FCCF. In all three counties, the co-op model also resulted in the highest estimated revenue requirements in most years of the forecast period (see Task 1.6.3). The acquisition of the incumbent IOUs by a co-op in these counties was assumed to be 100% debt financed, resulting in a large interest coverage requirement. Under the no capex adjustment scenario, the co-op model's forecast FCFF is at similar levels compared to those of the SB models in Hawaii and Honolulu counties, and the lowest in Maui and Kauai counties.

Additional analysis in subsequent sections will indicate whether the high revenue requirement estimates under a co-op model with adjustment for capex is unnecessarily burdensome on ratepayers or more effective in covering the HECO Companies' high levels of planned capex relative to their net income and cash flows.

Figure 4. Projected Free Cash Flow to Firm - by County and Ownership Model ($000s, nominal)



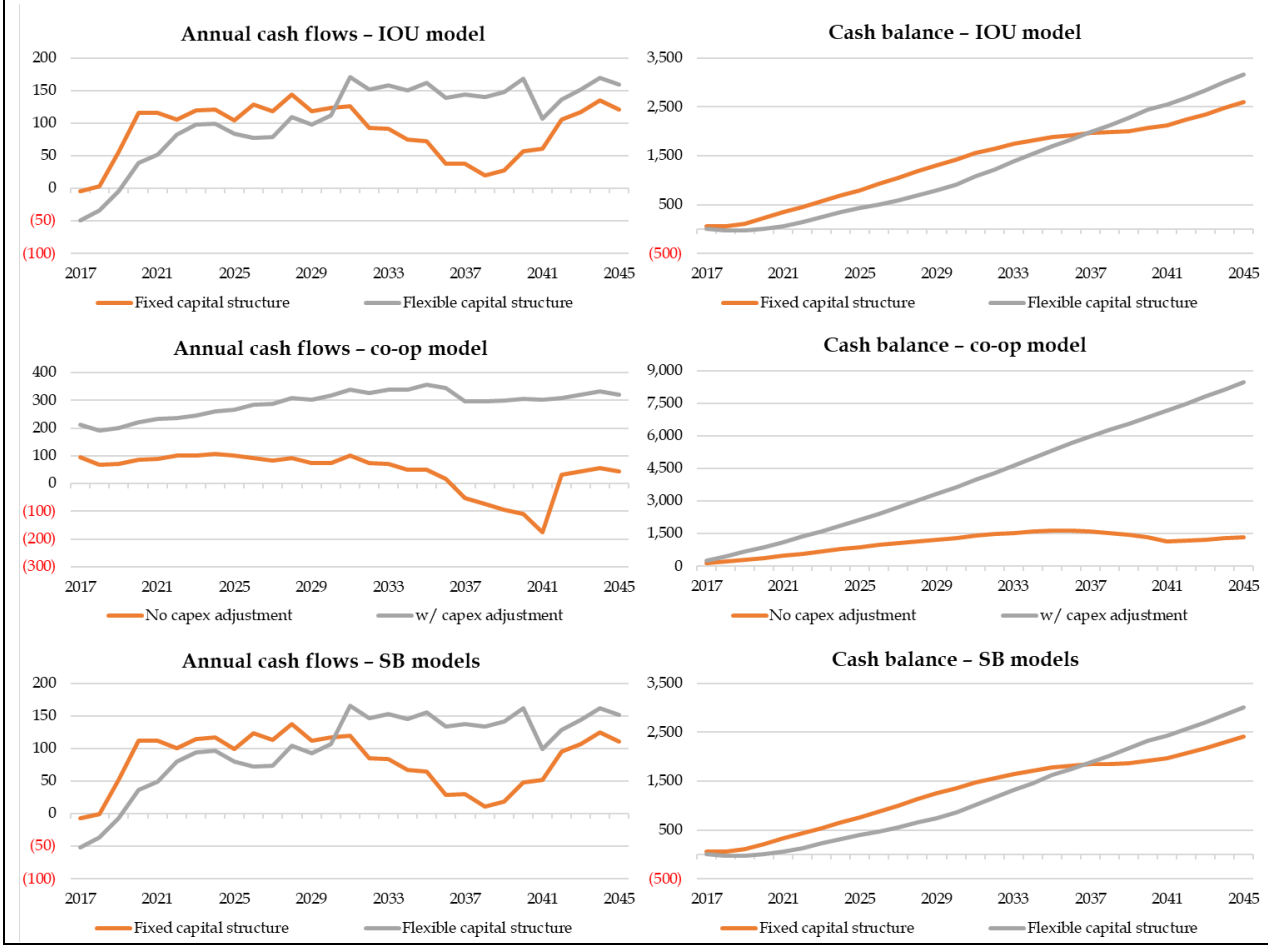
Revenue requirements decline between 2027 and 2031 under the co-op model (capex adjustment scenario) in Kauai County as estimated debt repayment obligations are reduced but keeping increasing under the IOU model. Again, further analysis will help determine whether the better financial health of the utility under the IOU model due to higher estimated FCFF is cost-effective to the ratepayers.

5.1 Honolulu County

5.1.1 Cash flows

The two SB models have near-identical estimated cash flows. The SB models also have similar but slightly lower cash flow estimates as the IOU model in Honolulu County. Cash flows are highest under the co-op model with capex adjustment. On the other hand, cash balances are expected to have the slowest growth under the co-op model without capex adjustment; cash balances are expected to grow steadily under all other models. Figure 5 shows the projected annual cash flows and cumulative cash balances in Honolulu County by ownership model.

Figure 5. Projected cash flows and balances by ownership model – Honolulu County ($MM, nominal)



The fixed capital structure scenario results in higher cash flows until 2030 from the issuance of common equity. By 2030, the utility is anticipated to raise $525 million from new equity under IOU and about $508 million under SB models. After 2030 however, equity must be retired in order to maintain the capital structure as planned capex declines after 2030. The flexible capital structure scenario is projected to generate higher cash flows after 2030; as a result, cash balances

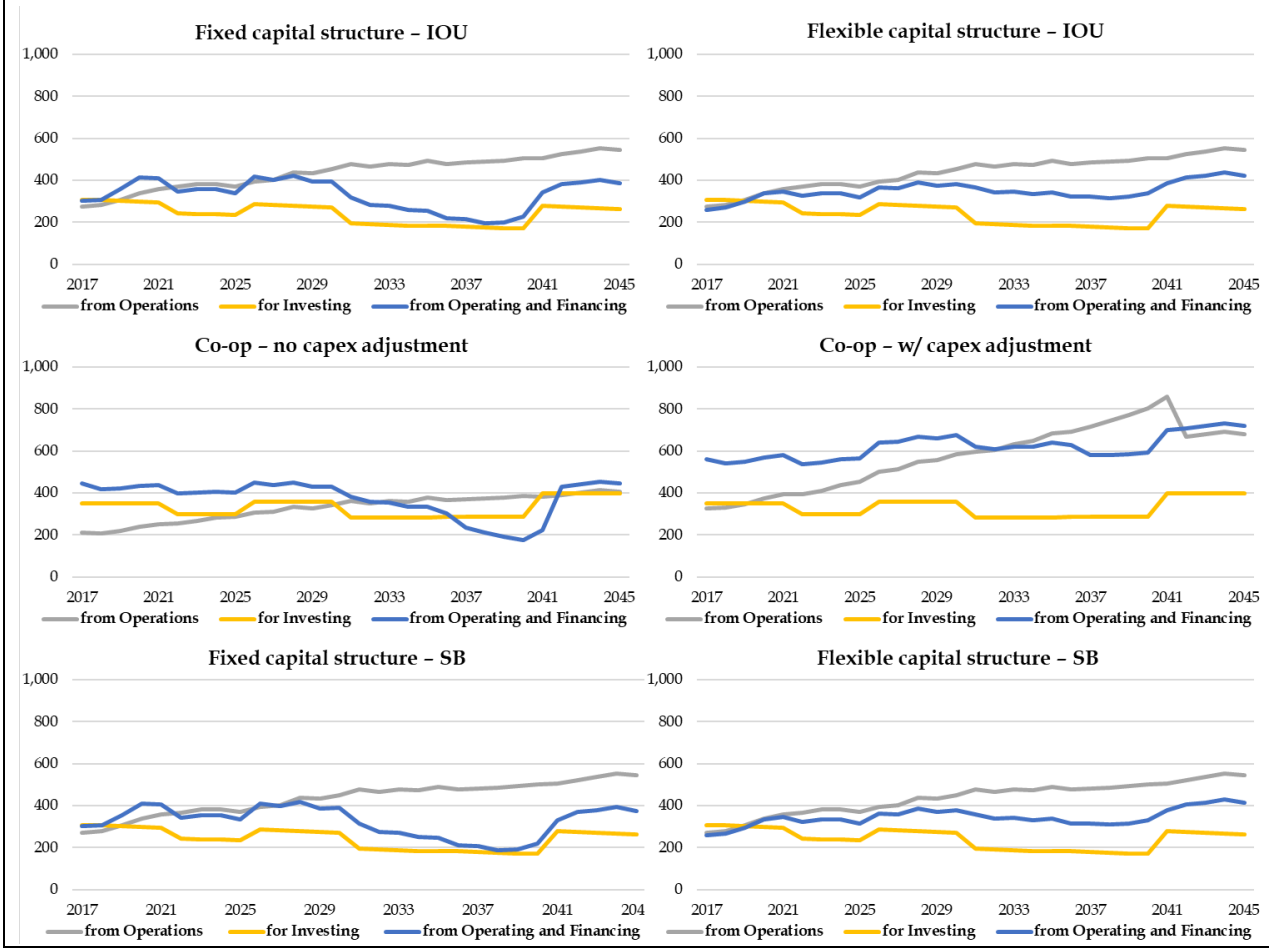
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are expected to grow faster in this scenario and more slowly under the fixed capital structure scenario, as can be seen in Figure 5.

Similarly, the capex adjustment scenario is expected to generate significantly higher cash flows under the co-op model because revenue requirements under this scenario generate high revenues (operating cash flows). The estimated constant growth in cash balances under this scenario suggests that this approach is unduly burdensome to ratepayers because the co-op continues to raise capital from equity (through the adjustment for capex) even though it has large balances of cash available which could be used instead.

5.1.2 Cash flows – source and use

Figure 6. Projected sources and use of cash – Honolulu County ($MM, nominal)



Cash required for investing and cash received from operations are identical under fixed and flexible capital structure approaches for the IOU-based models (IOU and SB). Investment needs (on capex) are likewise similar for co-op and SB models. As discussed earlier, cash from operations is the utility's primary source to fund investments as well as meet obligations to its current investors by making debt repayments and paying out dividends. The fixed capital structure approach allows HECO to align its expected cash inflows and outflows more closely, as

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shown on the left graphs in Figure 6 by the blue and yellow lines which stay approximately parallel throughout. The co-op model under the capex adjustment scenario maintains a cash buffer against its investment needs, as shown by the consistent spacing between blue and yellow lines.

5.1.3 Returns on equity

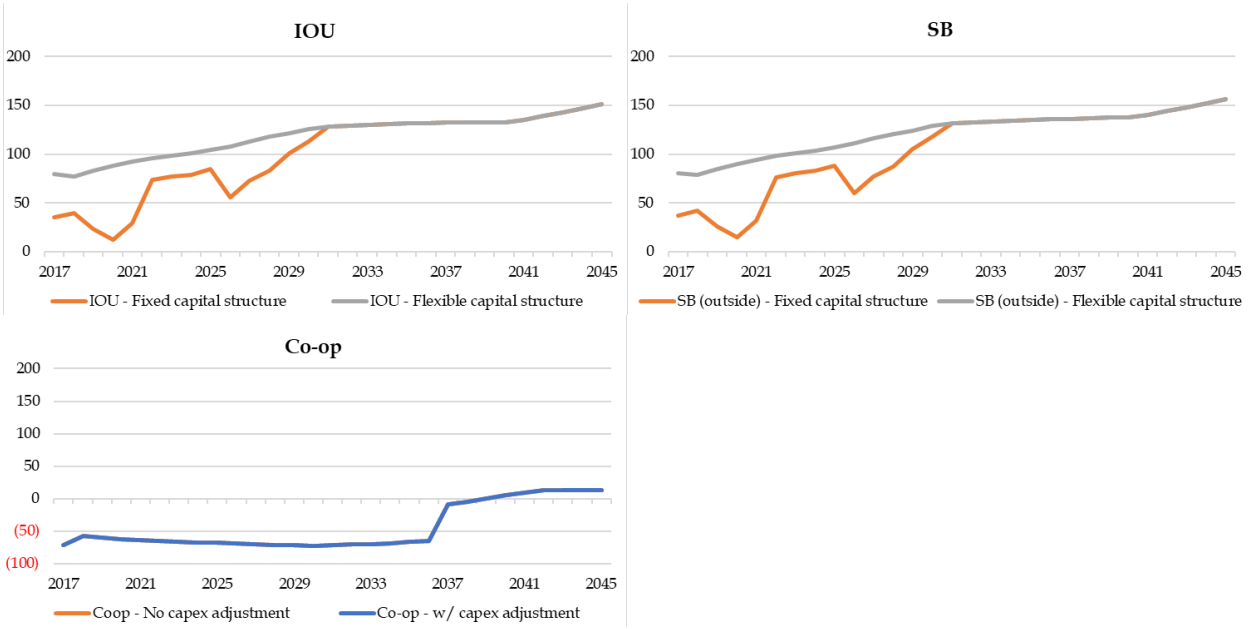
For the IOU and SB models, the fixed capital structure approach dilutes projected returns on equity. The additional equity raised initially does not alter net income forecasts, which remain the same in both approaches; consequently, the modeled dividends paid out to equity are also equal. Since equity capital has grown more under the fixed capital structure approach, the same amount of dividends are distributed among a larger pool of shareholders.

Due to savings on purchased power expenses, cash flows to equity are higher under the SB models (see Figure 7). Estimated net cash flows to utility were obtained by deducting new equity raised from the dividends paid (or deducing patronage capital raised from patronage capital retired for co-op). On the other hand, net cash flows to equity were anticipated to be the lowest under co-op model. This is not surprising as patronage capital contributions by co-op members are not made with an expectation of return. Co-op members are projected to receive positive cash flows only after 2037 once the remaining net margins from twenty years prior are returned to the members. Projected cash flows to equity under the co-op model are identical under both capex adjustment and no capex adjustment scenarios. The table below shows the estimated NPV of net cash flows to equity under different ownership models and scenarios.

Projected NPV of net cash flows to equity (9.5% discount rate[21])	Fixed capital structure	Flexible capital structure
Status Quo	$703 MM	$1,013 MM
Single Buyer	$736 MM	$1,038 MM
	Capex adjustment scenario	**No capex adjustment scenario**
Co-op	($576 MM)	($576 MM)

[21] Cost of equity for all three HECO Companies is 9.5%

Figure 7. Projected net cash flows to equity – Honolulu County ($MM, nominal)

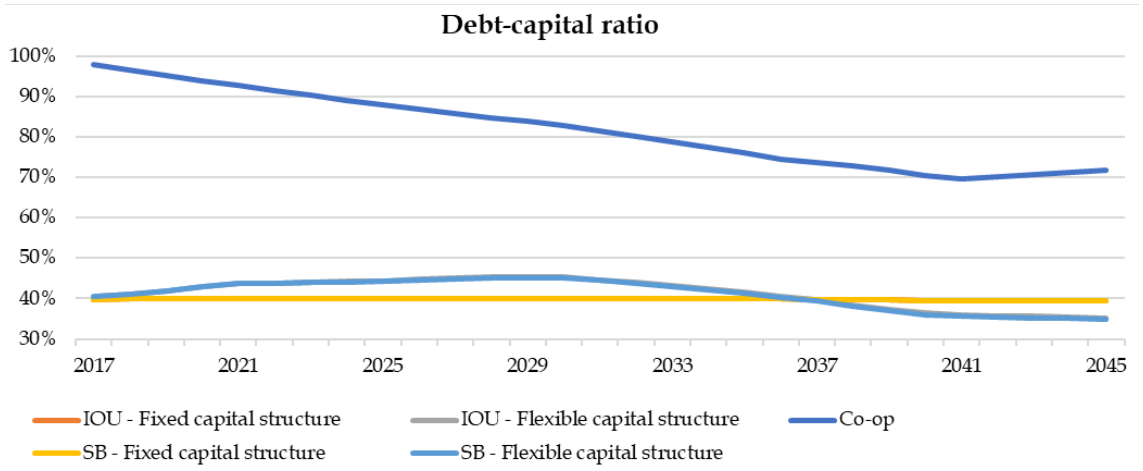


5.1.4 Leverage ratio

The leverage ratio is the proportion of debt that constitutes the company's capital. While the appropriate levels of leverage can vary by firms even within the same industry based on operations, higher leverage ratios can raise questions about the ability of the firm to make debt repayments when they are due. The fixed capital structure scenario for IOU and SB models are designed to maintain leverage ratios consistently around the current 40% levels. Using a flexible approach, leverage ratios are projected to rise to 45.3% under IOU and 45.1% under SB models in 2029, before decreasing steadily to about 35% in 2045. Under the co-op model, patronage capital is anticipated to grow steadily – debt-to-capital ratio is expected to fall to about 70% in 2041. Figure 8 shows how leverage ratios are forecast to change with each ownership model and the different scenarios.

The utility and the regulator must evaluate whether this change increases the financial risk of the firm enough to impact its borrowing costs. Likewise, diluting the returns to equity under the fixed approach may also impact the utility's share price and ability to raise capital. A comprehensive analysis of the most effective approach to raise the capital necessary for the planned capex is beyond the scope of this project; a potential "compromise" solution between the two approaches could be to allow the capital to vary within a set band (e.g., 55%-60% equity-to-capital ratio) by altering the combination of debt and equity capital raised.

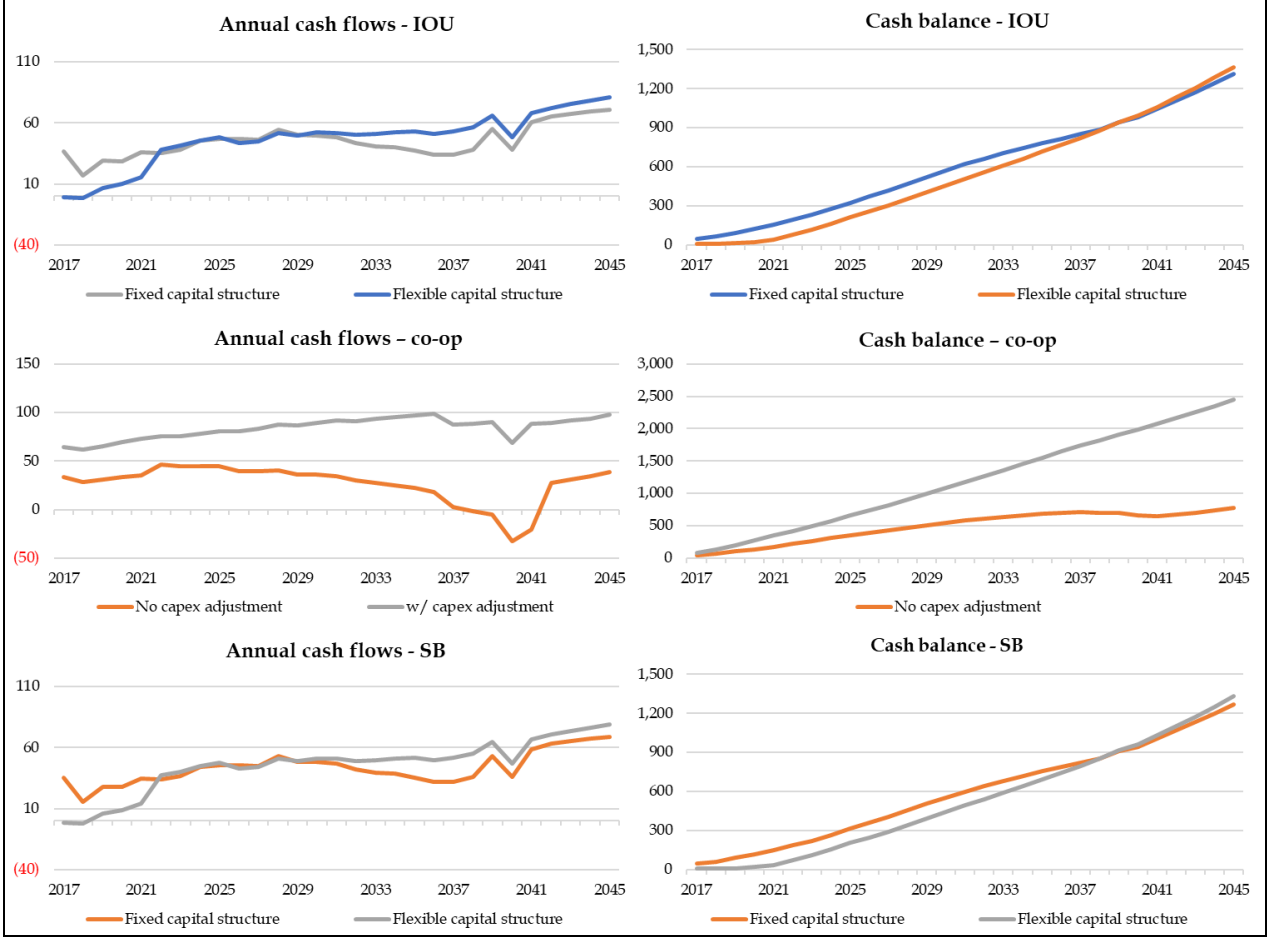
Figure 8. Honolulu County – projected leverage ratios by ownership model



5.2 Hawaii County

5.2.1 Cash flows

Figure 9. Projected cash flows and balances by ownership model – Hawaii County ($MM, nominal)



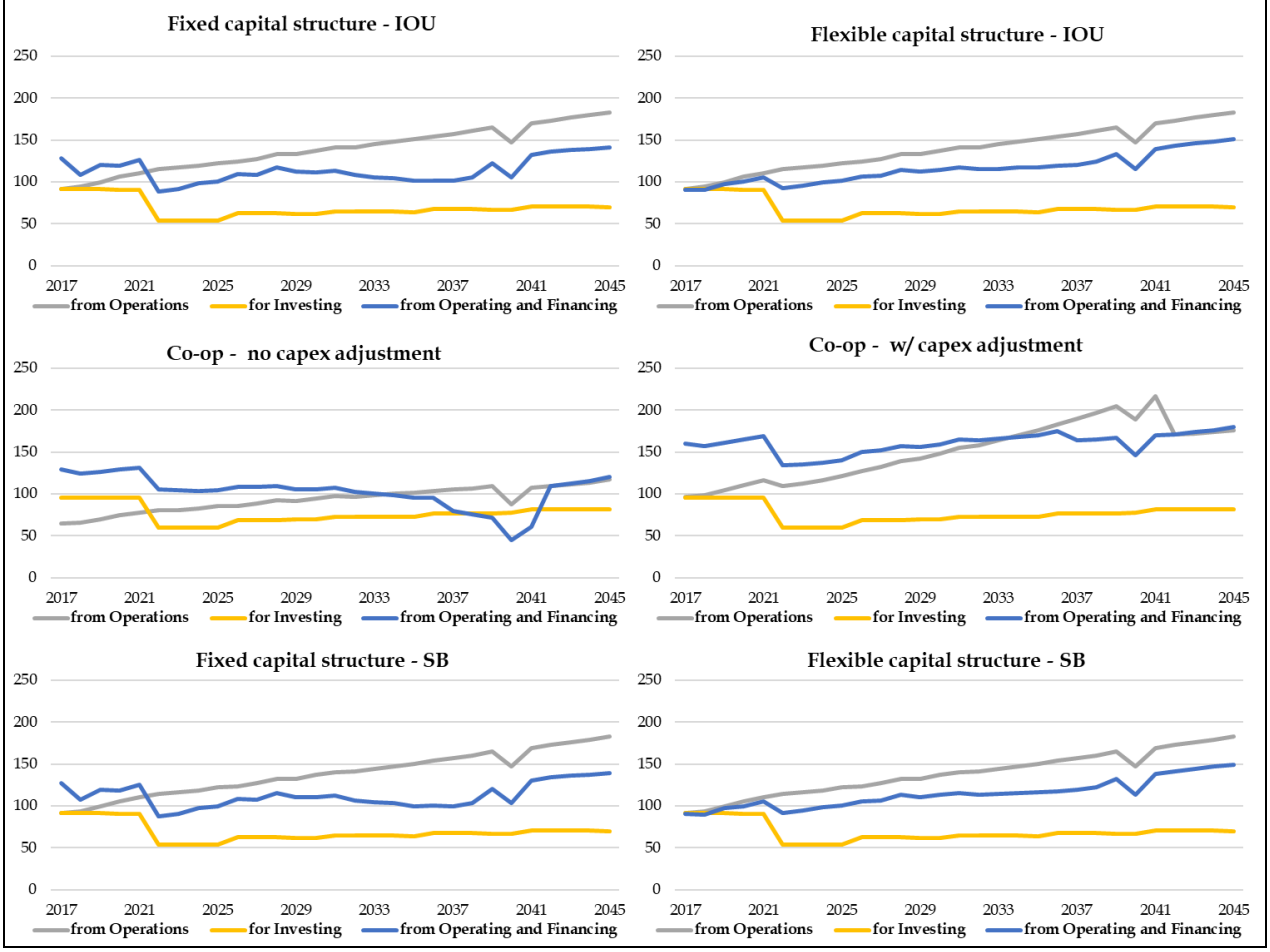
The IOU and SB models have almost identical estimated cash flows because of the underlying utility structure of an IOU in all three cases. Annual cash flow forecasts are highest under the co-op model with capex adjustment included and lowest under co-op without the adjustment. Cash balances are also expected to grow steadily except for the co-op model without capex adjustment, suggesting a more efficient use of capital. Figure 9 shows the projected annual cash flows and cumulative cash balances in Hawaii County by ownership model.

5.2.2 Cash flows – source and use

The fixed and flexible capital approaches show that estimated cash flows are similar in Hawaii County for IOU and SB models. This is because capex needs decline after 2021 and can be met through projected cash from operations. Figure 10 presents how the different models and scenarios are expected to generate cash flows (from operating and financing) to meet investment

needs. The IOU and SB models, as well as the co-op model with capex adjustment, generate sufficient cash flows from operations to cover investment needs. The co-op model without adjustment for capex requires additional financing initially to cover investments but generates sufficient cash flows from 2022 onwards.

Figure 10. Projected sources and use of cash – Hawaii County ($MM, nominal)



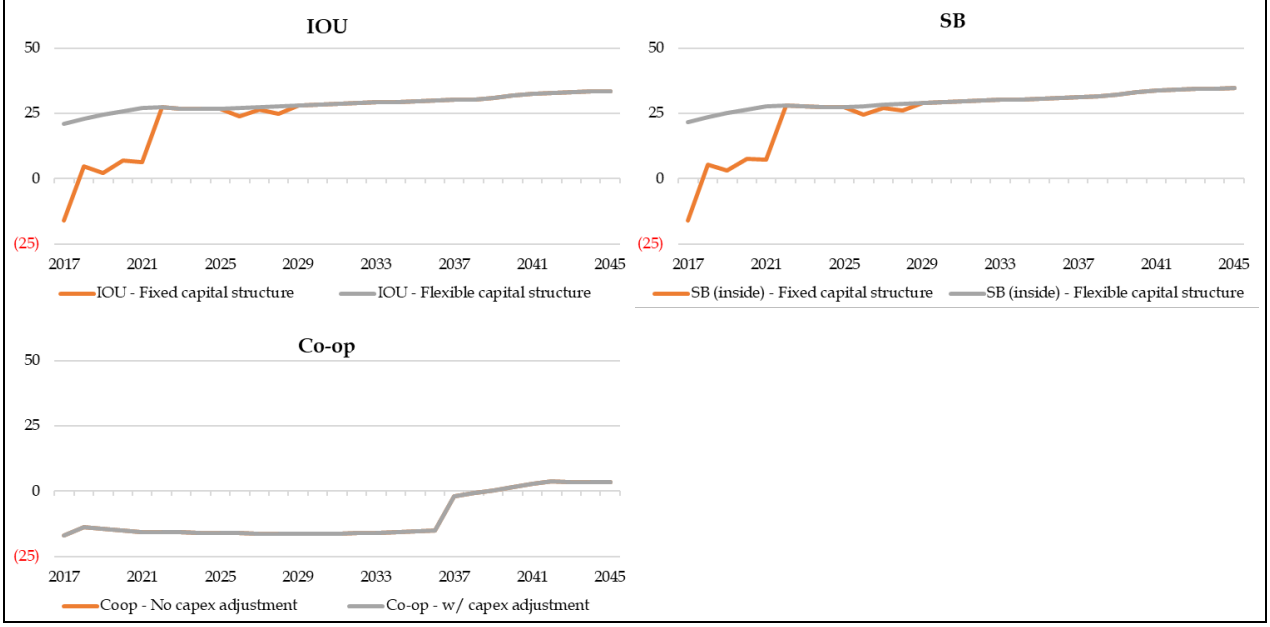
5.2.3 Returns on equity

The SB model is expected to generate 2% to 5% higher net cash flows to equity than the IOU model for most years of the forecast horizon, under both flexible and fixed capital structure scenarios. This result is driven by higher projected net income, resulting in higher dividends to shareholders, and lower amounts of capital raised under the fixed capital structure scenario. For both IOU and SB models, the flexible capital structure approach is expected to produce higher cash flows to equity – 69% higher for IOU and 64% higher for SB in NPV terms, as summarized in the table below.

Projected NPV of net cash flows to equity (9.5% discount rate)	Fixed capital structure	Flexible capital structure
Status Quo	$138 MM	$234 MM
Single Buyer	$147 MM	$241 MM
	Capex adjustment scenario	**No capex adjustment scenario**
Co-op	($136 MM)	($136 MM)

Projected cash flows to equity are at similar levels under IOU and SB models because the capex requirements of a SB is barely significant compared to the utility's capex. Net cash flows to equity are expected to be the same beyond 2030 under both fixed and flexible capital structure scenarios for IOU and SB models, as Figure 11 shows. However, it is important to note that these cash flows are distributed among a larger equity capital based under the fixed capital structure scenario, thus resulting in the lower NPV as seen in the table.

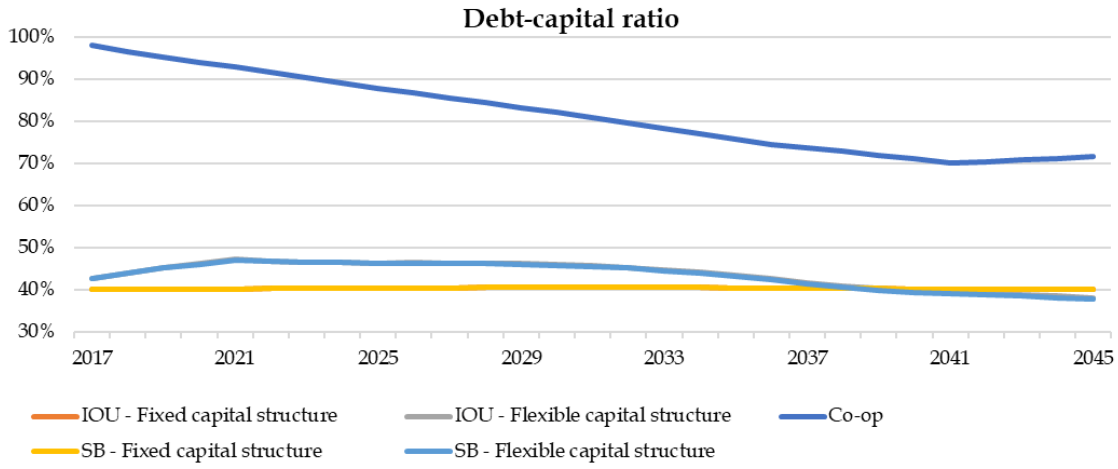
Figure 11. Projected net cash flows to equity – Hawaii County ($MM, nominal)



5.2.4 Leverage ratio

The fixed capital structure approach for IOU and SB models keep leverage ratios consistently around the current 40% levels. Using a flexible approach, leverage ratios are expected to rise to about 48% under IOU and SB models in 2021, before decreasing to about 40% in 2045. The co-op model is projected to build equity gradually – debt-to-capital ratio is projected to fall to about 70% in 2041. Figure 12 shows how leverage ratios are projected to change with each ownership model and different scenarios.

Figure 12. Hawaii County – projected leverage ratios by ownership model



5.3 Maui County

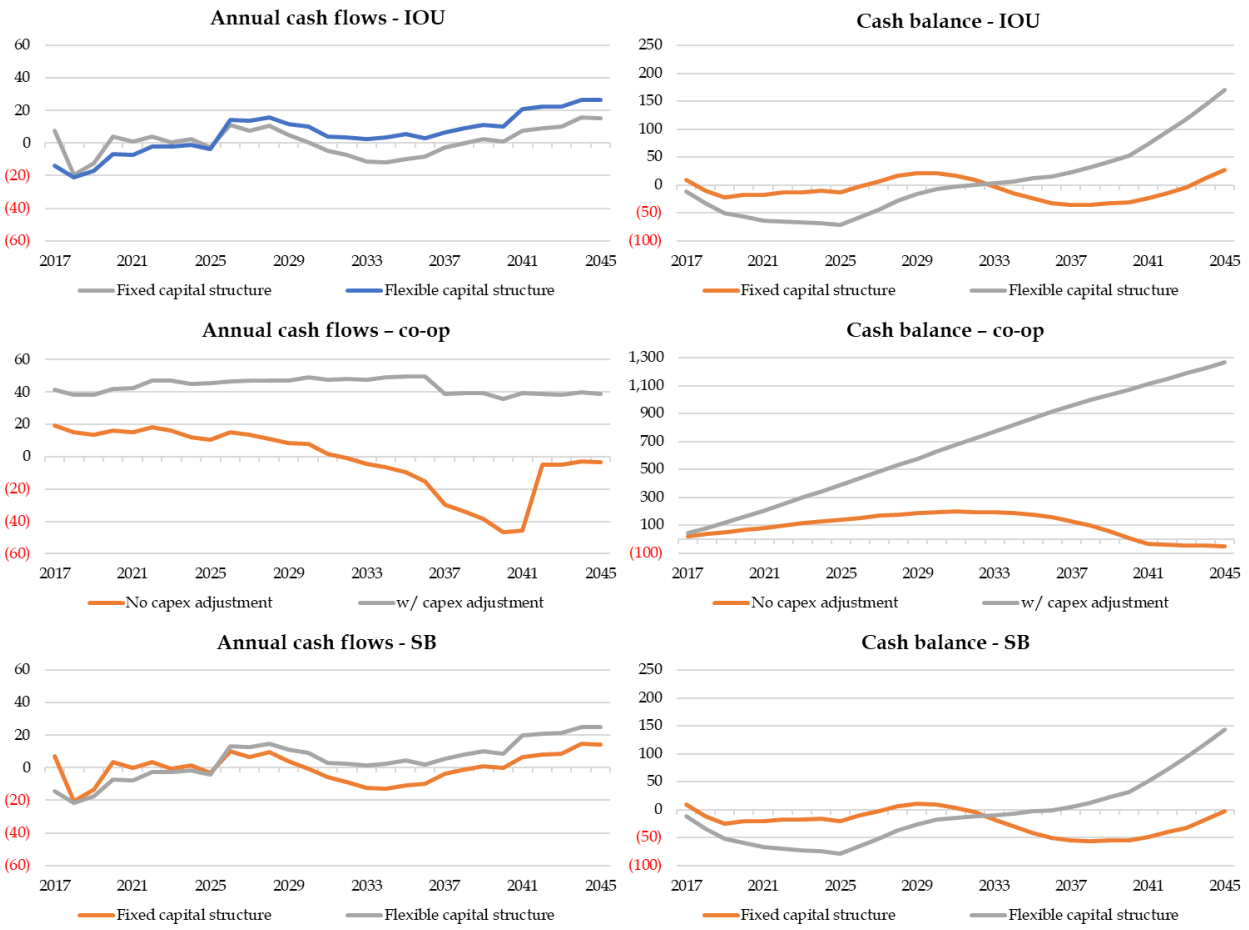
5.3.1 Cash flows

The IOU and SB models in Maui County are forecast to result in negative cash flows and cash balances for most of the years in the forecast horizon. The cash balances under the flexible capital structure scenario are expected to remain negative until 2038 in the IOU model and 2038-2039 in the two SB models. Under the fixed capital structure scenario in the IOU model, projected cash balances are less negative initially and become positive by the late 2020s but fall below zero again in the 2030s; cash balances remain negative throughout under the SB Outside model. The forecasts indicate that fixed capital structure scenario results in negative cash balances for more years of the forecast horizon than the flexible capital structure scenario.

Cash flows and cash balances are projected to be highest under the co-op model in the capex adjustment scenario. Cash balances under the no capex adjustment scenario are expected to become negative from 2041. Figure 13 shows the projected annual cash flows and cumulative cash balances in Maui County by ownership model.

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Figure 13. Projected cash flows and balances by ownership model – Maui County ($MM, nominal)

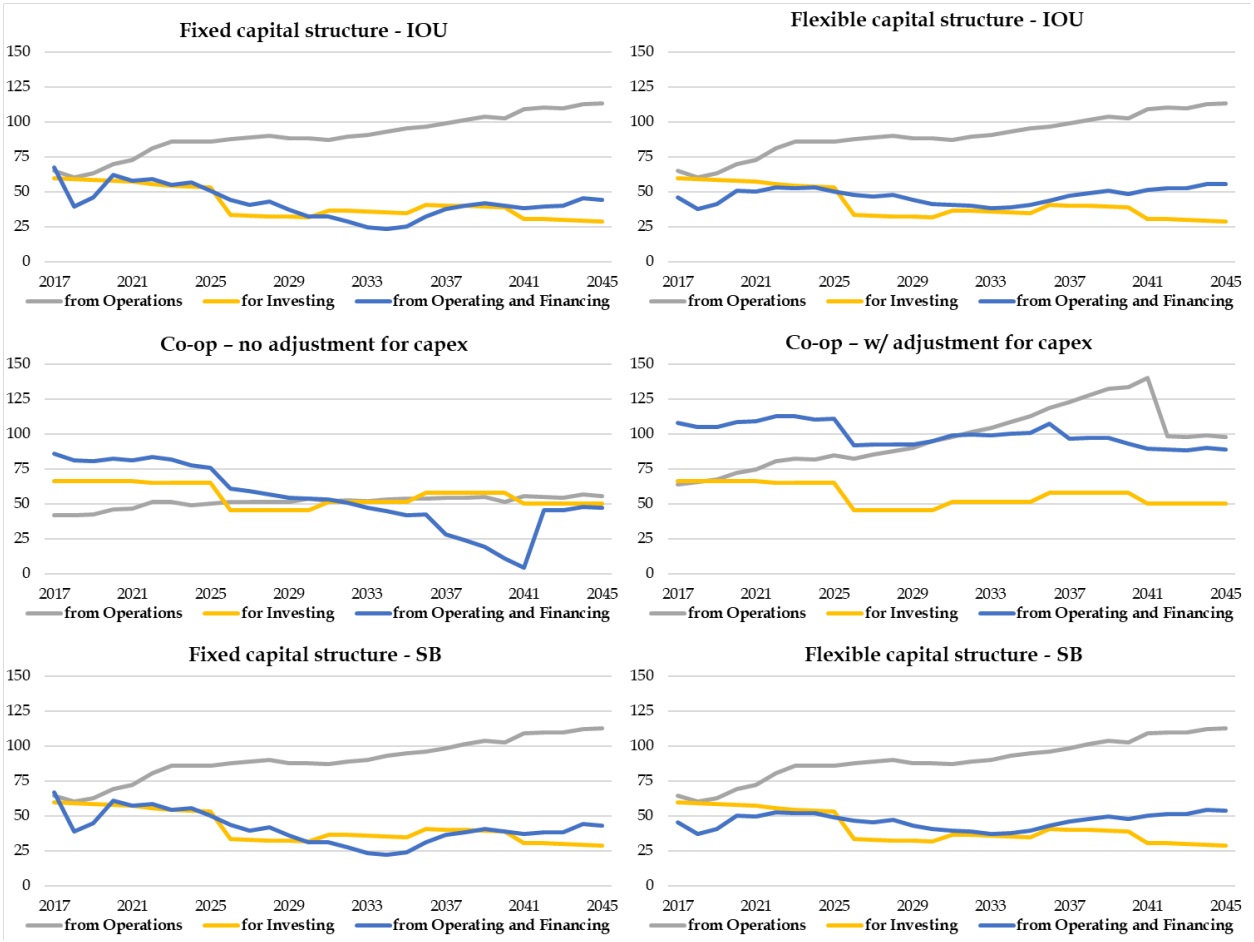


5.3.2 Cash flows – source and use

Negative cash balances in Maui County are an issue under IOU and IOU-based SB models because financing activities are forecast to generate negative cash flows throughout the forecast horizon – i.e., the utility's payments for debt service and dividend issuance are higher than the capital it raises. This is due to the high historical dividend payout ratio (relative to net income). As shown clearly in Figure 14, operating activities are projected to generate sufficient cash to meet planned capex, but the cash available after covering for financing needs is insufficient to cover investment needs in most years.

The co-op model in the capex adjustment scenario is expected to have sufficient cash flows from operating and financing activities to cover capex. In the no capex adjustment scenario, the utility is projected to generate sufficient cash flows to cover capex until 2031, after which its annual cash flows are expected to become negative; consequently, cash balances eventually become negative from 2041. Between 2032 and 2040, the utility uses up its cash balances to cover the annual shortfall in cash flow; this is indicated by the declining cash balance from 2032 in the co-op model under the no capex adjustment scenario in Figure 13.

Figure 14. Projected sources and use of cash – Maui County ($MM, nominal)



5.3.3 Returns on equity

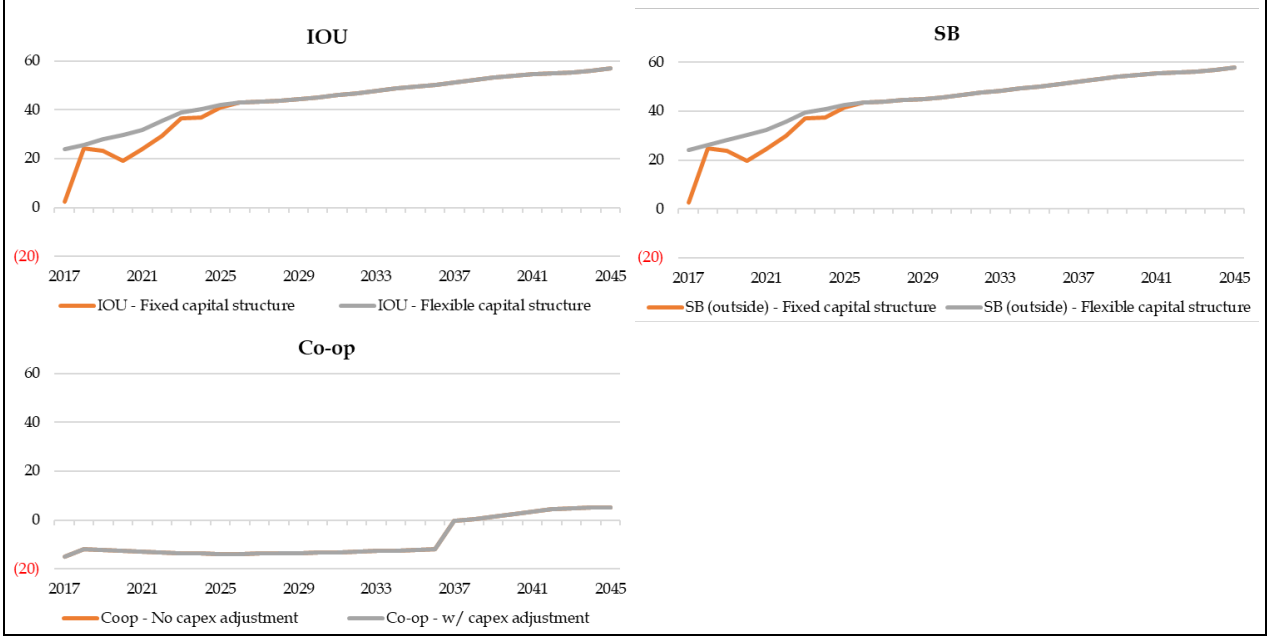
The SB model is expected to generate 1% to 4% higher net cash flows to equity than the IOU model every year, under both flexible and fixed capital structure scenarios. This is driven by higher projected net income, resulting in higher dividends to shareholders, and lower amounts of capital raised under the fixed capital structure scenario. For both IOU and SB models, the flexible capital structure approach is expected to produce 15% higher cash flows to equity in NPV terms, as summarized in the table below.

As in Hawaii County, Maui County's projected cash flows to equity are at similar levels under IOU and SB models. Net cash flows to equity are expected to be the same beyond 2025 under both fixed and flexible capital structure scenarios for IOU and SB models, as Figure 15 shows. Under the fixed capital structure scenario for both IOU and SB models, the utilities raise about $60 million in equity capital by 2025.

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Projected NPV of net cash flows to equity (9.5% discount rate)	Fixed capital structure	Flexible capital structure
Status Quo	$290 MM	$334 MM
Single Buyer	$296 MM	$339 MM
	Capex adjustment scenario	**No capex adjustment scenario**
Co-op	($113 MM)	($113 MM)

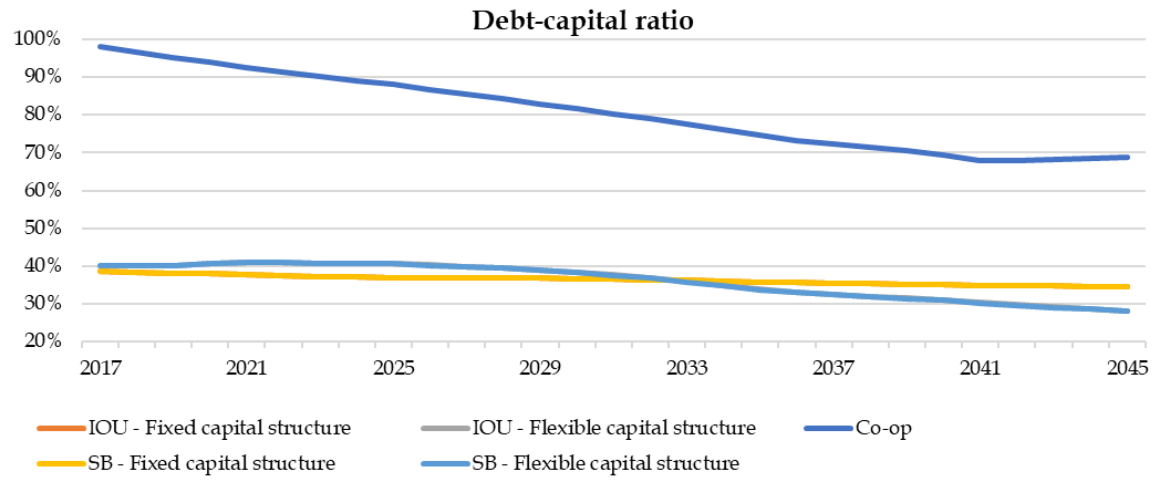
Figure 15. Projected net cash flows to equity – Maui County ($MM, nominal)



5.3.4 Leverage ratio

Leverage ratios are expected to decrease from about 39% to 35% under the IOU and SB models in Maui County in the fixed capital structure approaches; the decrease is sharper in the flexible capital structure approach – from 40% to 29%. Under the co-op model, the share of equity is expected to grow steadily until leverage ratio falls to about 68% in 2041. Figure 16 shows the projected evolution of leverage ratios under each ownership model and scenario.

Figure 16. Maui County – projected leverage ratios by ownership model



5.4 Kauai County

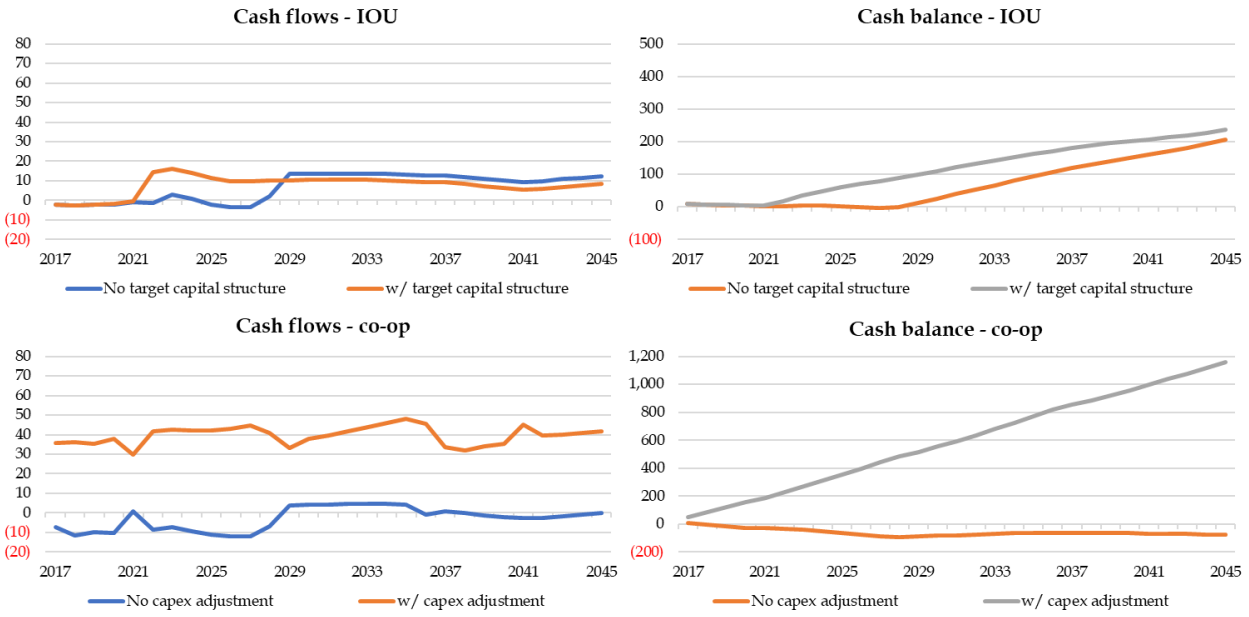
The incumbent utility in Kauai County is KIUC, an electric co-op. The SB models are also assumed to operate with a co-op utility. As described in the assumptions for Tasks 1.6.1 and 1.6.3, moving to SB models from a co-op is expected not to reduce purchased power costs further. As a result, the cash flows for co-op and SB models in Kauai County are virtually identical.

5.4.1 Cash flows

Annual cash flow forecasts are highest under the co-op model in the capex adjustment scenario and lowest under no capex adjustment scenario for the co-op model. Cash balances and expected grow steadily in the IOU model under both fixed and flexible capital structure scenarios after an initial transition period. Under the co-op model, cash balances are projected to remain negative after 2018 in the no capex adjustment scenario; in the capex adjustment scenario, cash balances are forecast to grow consistently to $1.2 billion in 2045. These forecasts suggest that determining revenue requirements using the capex adjustment initially (up to 2022) and without it thereafter would provide KIUC with sufficient cash on hand and keep rates lower in the long term. Figure 17 shows the projected annual cash flows and cumulative cash balances in Kauai County for IOU and co-op models.

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617-933-7225
gabriel@londoneconomics.com

Figure 17. Projected cash flows and balances by ownership model – Kauai County ($MM, nominal)

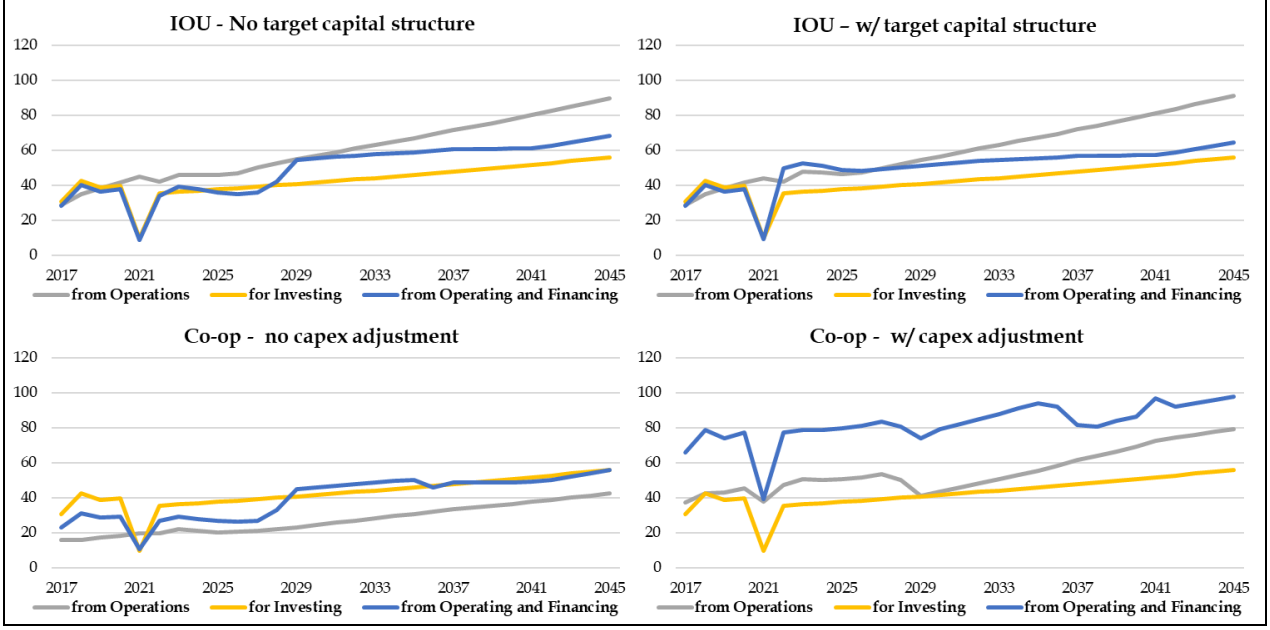


5.4.2 Cash flows – source and use

The cash balance under a co-op model in the capex adjustment scenario is expected to keep growing because cash generated is projected to be substantially higher than capex needs; in the alternate no capex adjustment scenario, the co-op is forecast to generate insufficient cash to cover its planned capex during most years of the forecast horizon. As shown in Figure 18, the blue line indicated cash from operating, and financing are substantially higher than the yellow line indicating investment needs in the capex adjustment scenario but lower for most years in the no capex adjustment scenario.

After the transition to an IOU model, the cash flows are estimated to be similar under both the target capital structure and flexible capital structure scenarios for the successor IOU after the transition period. The analysis assumes a transition period of 5 years; therefore, the utility is expected to generate additional capital between 2022 and 2029 in the target capital structure scenario.

Figure 18. Projected sources and use of cash – Kauai County ($MM, nominal)



5.4.3 Returns to equity

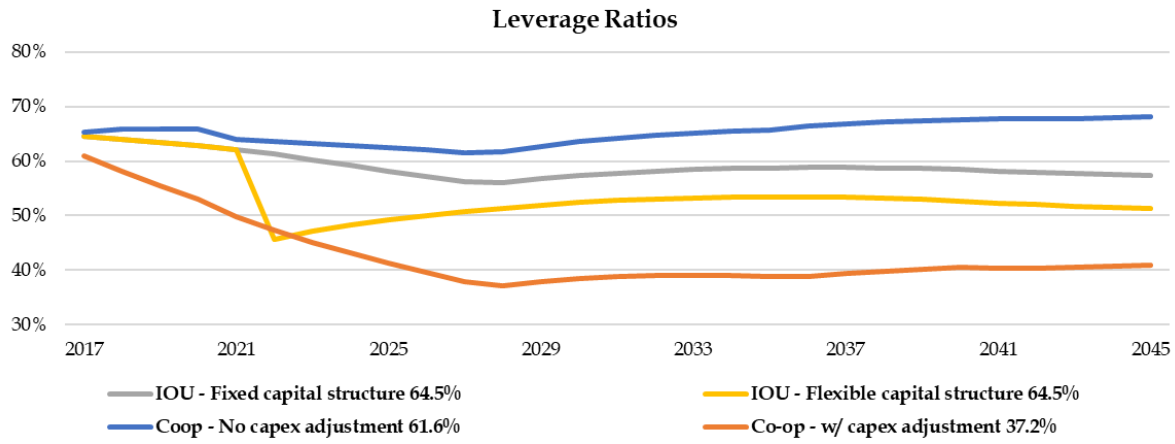
The IOU model is expected to generate the highest cash flows to equity under the flexible capital structure scenario; NPV of cash flows to equity in the target capital structure scenario is projected to be 27% lower. Likewise, the capex adjustment scenario is foreseen to place a six-fold higher burden on equity holders (the ratepayers) compared to the no capex adjustment scenario.

Projected NPV of net cash flows to equity (8% discount rate)	Capex adjustment scenario	No capex adjustment scenario
Status Quo (co-op)	($198 MM)	($33 MM)
	Flexible capital structure	**Target capital structure**
IOU	$125 MM	$91 MM

5.4.4 Leverage ratio

Leverage ratios are not expected to change significantly under the co-op model in the no capex adjustment scenario; in the capex adjustment scenario, the share of equity is forecast to grow sharply until leverage ratio falls to about 37% in 2028. In the flexible capital structure scenario for the IOU model, the equity-capital ratio is forecasted to increase steadily until 2028 and stabilize thereafter. Under a target capital structure scenario, a jump in the share of equity is expected after the transition period after which it is projected to remain stable. This uptick in the share of equity can be seen as a dip in the leverage ratio in Figure 19.

Figure 19. Kauai County – projected leverage ratios by ownership model



6 Appendix A: Scope of work to which this deliverable responds

1.6.2 Analysis of how each ownership model would affect cash flows. CONTRACTOR shall provide an analysis describing the cash flows of each model, including an overview of the accounting differences between ownership models (accrual vs. cash basis) and the treatment of 1) operations and maintenance expense; 2) taxes; 3) financing capital improvements; 4) depreciation; and 5) return on invested capital. CONTRACTOR shall include a summary of how net revenues are distributed.

DELIVERABLE FOR TASK 1.6.2. CONTRACTOR shall provide its conclusions and all work related to an analysis of how each ownership model would affect cash flows. CONTRACTOR shall include discussion of accrual versus cash accounting and the treatment of topics such as operations and maintenance expenses, taxes, financing capital improvements, depreciation, and return on invested capital; and how net revenues are distributed. CONTRACTOR shall explain conceptually why these differences exist and illustrate the differences with simple examples that are consistent across all ownership models. CONTRACTOR shall provide an MS Word document, with MS Excel spreadsheets and supporting documents. CONTRACTOR shall submit deliverable for TASK 1.6.2 to the STATE for approval.

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Comparison of projected average retail rates under each ownership model

prepared for the Hawaii Department of Business, Economic Development & Tourism ("DBEDT") by London Economics International LLC

October 19, 2018

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This document, Task 1.6.4, is one of several working papers issued as part of this engagement. It provides a matrix comparing the projected system average retail rates under each ownership model through 2045 for an average residential, commercial, and industrial customer. In general, the estimated rates follow the pattern of growth in overall revenue requirement for each utility and ownership model but do not increase as fast as the revenue requirement since there is also growth in load and number of customers.

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List of acronyms

AED Method	Average-Excess Demand Method
Co-op	Cooperative
DBEDT	Hawaii Department of Business, Economic Development, and Tourism
HECO	Hawaiian Electric Company
HEI	Hawaiian Electric Industries Inc.
HELCO	Hawaii Electric Light Company
IOU	Investor-Owned Utility
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company
NARUC	National Association of Regulatory Utility Commissioners
NARUC Manual	NARUC Electric Utility Cost Allocation Manual
NCD Method	Non-Coincident Demand Method
O&M	Operations and Maintenance
PR Method	Peak Responsibility Method
PUC	Hawaii Public Utilities Commission
SB	Single Buyer
TOU	Time-of-Use

1 Executive Summary

London Economics International LLC, together with Meister Consultants Group (the "Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which corresponds to Task 1.6.4 in the project scope of work, provides a matrix comparing the estimated system average retail rates under each ownership model through 2045 for an average residential, commercial, and industrial customer. Furthermore, this memo illustrates the projected average consumption level for the different customer classes and demonstrates how the average system rate and the aggregate bill may change through 2045 for each ownership model.

1.1 Rate structure for utilities in the State of Hawaii

In the State of Hawaii, as is typical of the electricity industry, electricity rates vary among different customer classes. The Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Ltd. ("MECO"), collectively referred to as the "HECO Companies" in this memo, and the Kauai Island Utility Cooperative ("KIUC") have similar ratemaking procedures, including functionalization, classification, and allocation of costs necessary to render service, which then inform how rates are calculated for each customer class from the overall revenue requirement. Customer classes include residential, commercial (or general service), large power service, and other (street lighting, electric vehicles, etc.), and each class may include sub-classes. This memo focuses on the residential, commercial, and large power customer classes.

1.2 Rate estimates for all utilities and ownership models per customer class

In order to calculate electricity rates under the various ownership models through to 2045, the Project Team relied on the load forecast for each county in the State (Task 1.5.2) as well as the revenue requirement forecast for each county under the different ownership models (Task 1.6.3). Furthermore, the Project Team used the historical cost allocation factors, reflected in historical average rates for each utility and customer class, to estimate future rates for typical residential, commercial, and large power users.

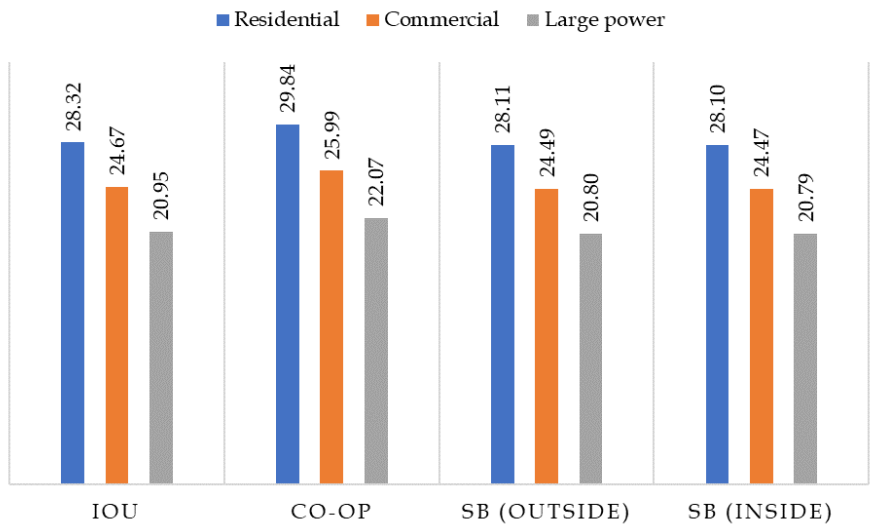
Of note is that the rates follow the pattern of growth in overall revenue requirement for each utility and ownership model, but do not grow as fast as the revenue requirement given the flat to moderate increase in load and number of customers. The Project Team also notes that the differences in rates between ownership models are predominantly driven by their differences in revenue requirements (as discussed in Task 1.6.3), as load forecasts do not vary between the models.

The average rates presented in this section correspond to the average over the forecast horizon of annual rates, converted from nominal dollars into constant 2017 dollars.

1.2.1 HECO projected average rates

On average, the Single Buyer ("SB") models are projected to provide the lowest average rate from 2018 to 2045 across all the customer classes. Over the forecast horizon, average rates for HECO residential customers in Honolulu County are anticipated to range from 28.1 cents/kWh under the SB models, to 28.3 and 29.8 cents/kWh respectively for the investor-owned utilities ("IOU") and cooperative ("co-op") models. Commercial and large power rates are similarly impacted, with the SB models showing lower average rates than the other models, and the co-op model resulting in the highest rates. These results are illustrated in Figure 1.

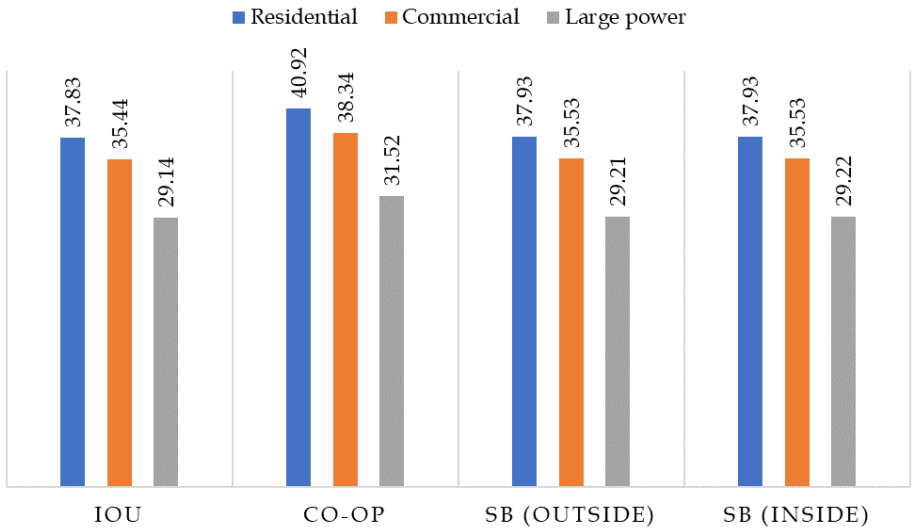
Figure 1. Projected average rates over forecast horizon in Honolulu County for each ownership model (2017 cents/kWh)



1.2.2 HELCO projected average rates

In Hawaii County, the status quo is expected to provide the lowest average electricity rates among the models reviewed across the customer classes. The HELCO average rates for residential customers over the forecast horizon are anticipated to be the highest under the co-op model around 40.9 cents/kWh, followed by 37.9 cents/kWh under the SB models, and 37.8 cents/kWh under the IOU model. Commercial and large power rates are similarly impacted. These results are illustrated in Figure 2.

Figure 2. Projected average rates over forecast horizon in Hawaii County for each ownership model (2017 cents/kWh)



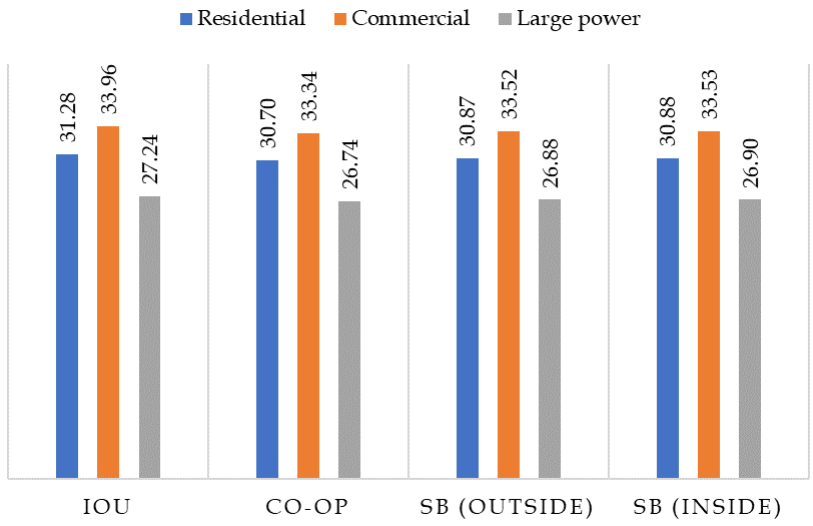
1.2.3 MECO projected average rates

For Maui County, the Project Team conducted separate analyses to evaluate the impact on rates from ownership change on both a county-wide basis and separately for each island (Maui, Lanai, and Molokai). A county-wide change in ownership model would allow the islands to share the fixed costs associated with the SB models. For the co-op model, however, both approaches would have a similar impact on rates since MECO's overall valuation was allocated to each island in the same proportion under both approaches. The approach is described further in Section 4.2.3.

1.2.3.1 MECO projected average rates – county-wide ownership model change

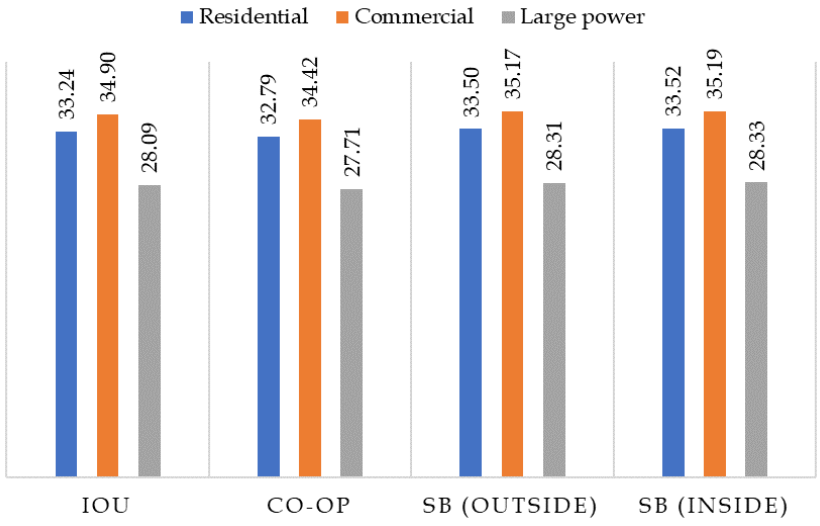
The co-op model is expected to provide the lowest average rates on all three islands of Maui County. This is the case for all the customers classes including residential, commercial, and large power users. On the island of Maui, average rates for MECO residential customers over the forecast horizon are anticipated to be around 30.7 cents/kWh under the co-op model, 30.9 cents/kWh under the SB models, and slightly higher at 31.3 cents/kWh for the IOU model. Commercial and large power rates are similarly impacted; results are illustrated in Figure 3.

Figure 3. Projected average rates over forecast horizon on the island of Maui for each ownership model (2017 cents/kWh)



On the island of Lanai in Maui County, average rates for MECO residential customers over the forecast horizon are anticipated to be lowest under the co-op model at around 32.8 cents/kWh. Average rates for MECO residential customers over the forecast horizon are slightly higher under the IOU and SB models at around 33.2 cents/kWh and 33.5 cents/kWh, respectively. Commercial and large power rates mimic a similar pattern, as shown in Figure 4.

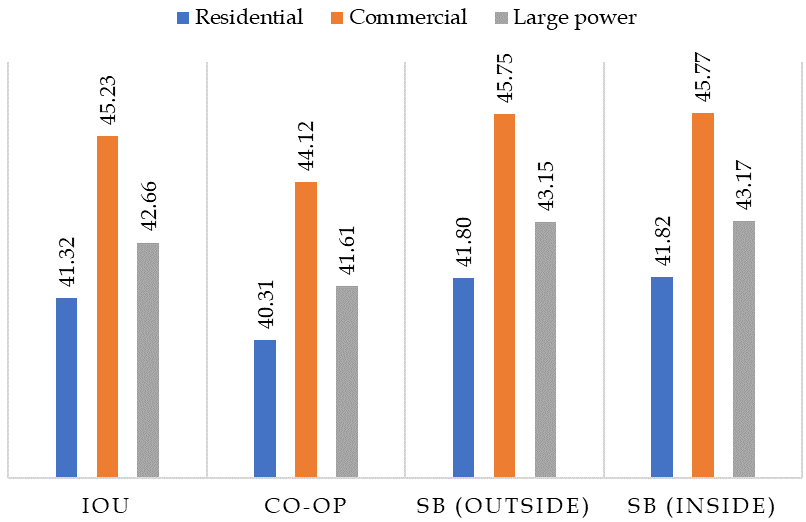
Figure 4. Projected average rates over forecast horizon on the island of Lanai for each ownership model (2017 cents/kWh)



Lastly, on the island of Molokai in Maui County, average rates over the forecast horizon for MECO residential customers are anticipated to be lowest under the co-op model at around 40.3

cents/kWh. Under the IOU and SB models, average forecasted rates for residential customers from 2018 to 2045 are higher at around 41.3 cents/kWh and 41.8 cents/kWh, respectively. On average, commercial rates are highest over the forecast horizon, followed by large power rates. Nonetheless, both commercial and large power rates are similarly impacted; these results are shown in Figure 5.

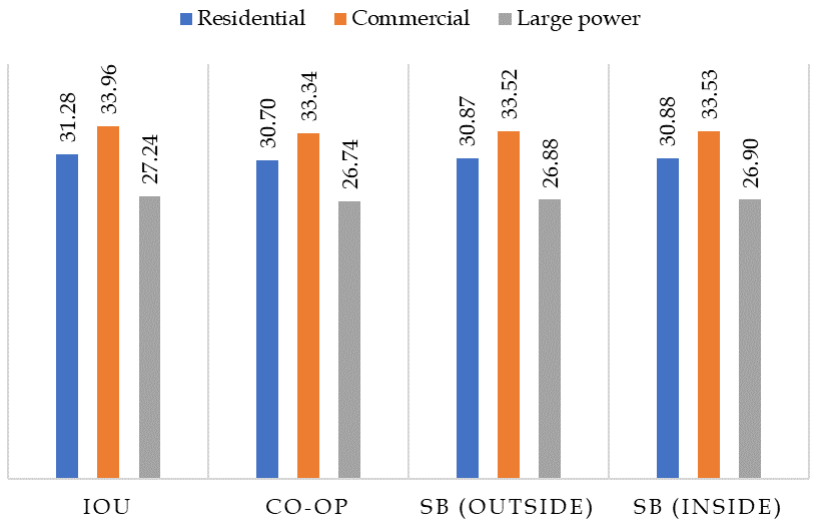
Figure 5. Projected average rates over forecast horizon on the island of Molokai for each ownership model (2017 cents/kWh)



1.2.3.2 MECO projected average rates – ownership model change by island

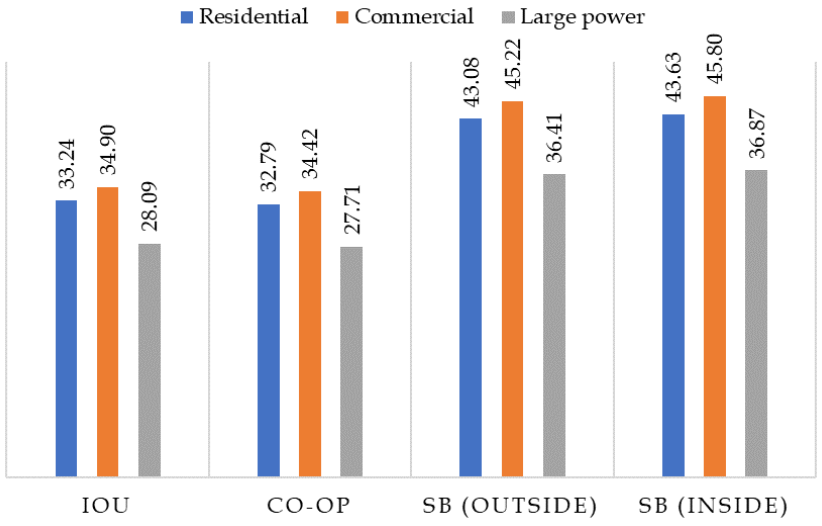
The co-op model is expected to provide the lowest average rates on all three islands of Maui County but the SB models are projected to significantly raise average rates on the islands of Lanai and Molokai. This is case for all the customers classes including residential, commercial, and large power users.On the island of Maui in Maui County, average rates for MECO residential customers over the forecast horizon are anticipated to be around 30.7 cents/kWh under the co-op model, and slightly higher at 30.9 cents/kWh and 31.3 cents/kWh for the SB and IOU models, respectively. Commercial and large power rates are similarly impacted; results are illustrated in Figure 6.

Figure 6. Projected average rates over forecast horizon on the island of Maui for each ownership model (2017 cents/kWh)



On the island of Lanai in Maui County, average rates for MECO residential customers over the forecast horizon are anticipated to be highest under the SB (inside) model at around 43.6 cents/kWh. Average rates for MECO residential customers over the forecast horizon are relatively lower under the IOU and co-op models at around 33.2 cents/kWh and 32.8 cents/kWh, respectively. Commercial and large power rates mimic a similar pattern, as shown in Figure 7.

Figure 7. Projected average rates over forecast horizon on the island of Lanai for each ownership model (2017 cents/kWh)

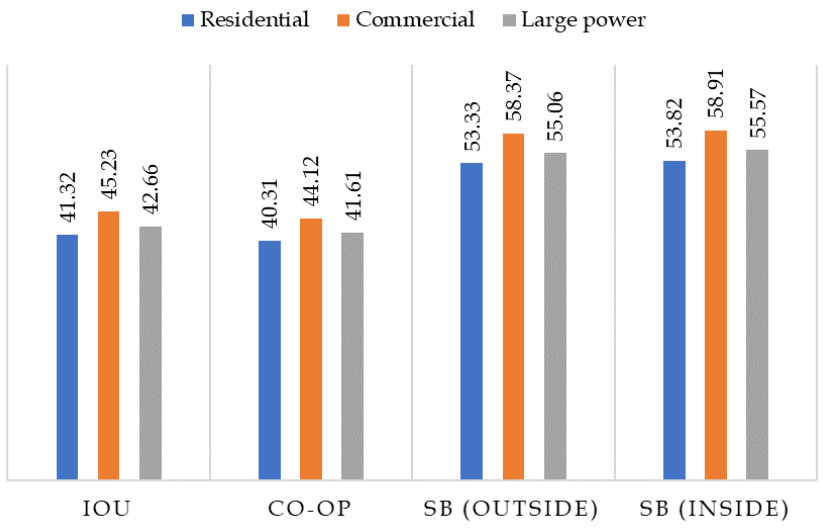


Lastly, on the island of Molokai in Maui County, average rates over the forecast horizon for MECO residential customers are anticipated to be lowest under the co-op model at around 40.3

cents/kWh and slightly higher under the IOU model at 41.3 cents/kWh, respectively. Under the SB models, average forecasted rates for residential customers from 2018 to 2045 are higher than that of the IOU and co-op models, at around 53.8 cents/kWh and 53.3 cents/kWh under the SB (inside) and SB (outside) models, respectively. On average, commercial rates are highest over the forecast horizon, followed by large power rates. Nonetheless, both commercial and large power rates are similarly impacted; these results are shown in Figure 8.

The SB models are expected to lower rates on the island of Maui but raise rates substantially on both Lanai and Molokai because of the smaller sizes of the latter islands. On Maui, the reduced costs of procuring power from IPPs is expected to outweigh the incremental expenses from the SB's operations. But Lanai and Molokai are both small enough that the administrative and capital expenditures needed for SB operations represent a much larger proportion of their operating expenses and cannot be offset by reduced power supply expenses.

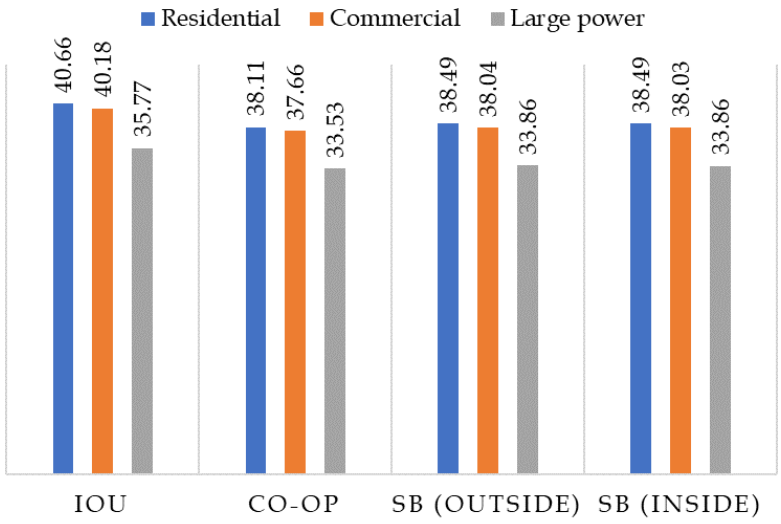
Figure 8. Projected average rates over forecast horizon on the island of Molokai for each ownership model (2017 cents/kWh)



1.2.4 KIUC projected average rates

Finally, in Kauai County, the co-op is expected to provide the lowest average rates for all the customers classes. The average rates over the forecast horizon for KIUC residential customers are anticipated to be the highest under the IOU model, at around 40.7 cents/kWh, followed by approximately 38.5 cents/kWh under the SB models, and 38.1 cents/kWh under the co-op model. Commercial and large power rates, too, are similarly impacted, with the highest projected average rates found under the IOU model and the lowest under the co-op model. These results are illustrated in Figure 9.

Figure 9. Projected average rates over forecast horizon in Kauai County for each ownership model (2017 cents/kWh)



1.3 Summary of ownership model changes on rates

The overall impact of a change in ownership model on residential rates varies significantly by county. A co-op model is expected to increase average rates, relative to the status quo, on Honolulu and Hawaii counties but lower them on Maui County. The SB models are expected to result in lower average rates than the status quo IOU in Honolulu County and the island of Maui, but higher elsewhere. These results are summarized below in Figure 10.

Figure 10. Impact of ownership changes on average residential rates (2018 - 2045)

Change of the Ownership Model	Honolulu County	Hawaii County	Maui County	Kauai County
Move to a co-op model	↑ 5.3%	↑ 8.2%	↓ -1.8%	
Move to a Single Buyer within the utility model	↓ -0.7%	↑ 0.3%	↓ -1.3%	↑ 1.0%
Move to a Single Buyer outside the utility model	↓ -0.8%	↑ 0.3%	↓ -1.3%	↑ 1.0%
Move to an IOU model				↑ 6.7%

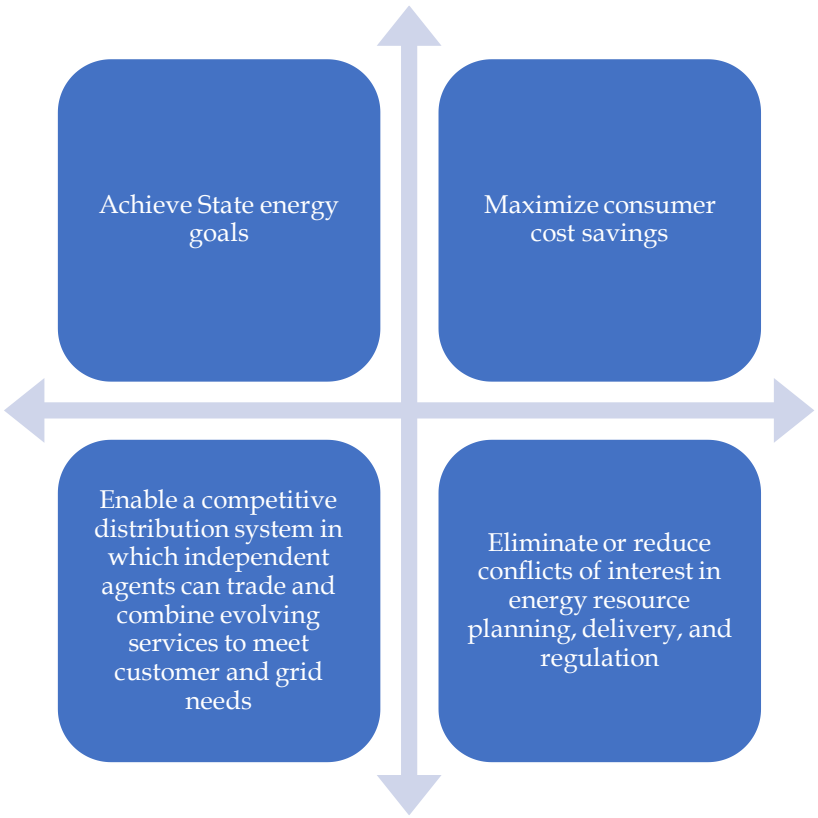
Maui County – county-wide ownership model change	Maui	Lanai	Molokai
Move to a co-op model	↓ -1.8%	↓ -1.4%	↓ -2.5%
Move to a Single Buyer within the utility model	↓ -1.3%	↑ 0.8%	↑ 1.2%
Move to a Single Buyer outside the utility model	↓ -1.3%	↑ 0.8%	↑ 1.2%

Maui County – ownership model change by island	Maui	Lanai	Molokai
Move to a co-op model	↓ -1.8%	↓ -1.4%	↓ -2.5%
Move to a Single Buyer within the utility model	↓ -1.3%	↑ 29.6%	↑ 29.1%
Move to a Single Buyer outside the utility model	↓ -1.3%	↑ 31.2%	↑ 30.3%

2 Introduction and scope

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the State legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. LEI, through a competitive sealed proposals procurement,[1] was contracted to perform this study.[2]

Figure 11. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

The goal of the project is to assess the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[3] listed in Figure 11. The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the State. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory

[1] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[2] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[3] House Bill No. 1700 Relating to the State Budget.

models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[4]

2.1 Role of this deliverable relative to others in the project

This deliverable corresponds to Task 1.6.4 in the project scope of work. It includes a matrix comparing the projected system average retail rates under each ownership model through 2045 for an average residential, commercial, and industrial customer. Furthermore, this memo illustrates the average consumption level for the different customer classes and shows how the average system rate and the aggregate bill may change through 2045 for each ownership model.

2.2 Future refinements

As noted earlier, this deliverable is subject to further improvement and modification as the project moves forward or as more information is made available to the Project Team.

[4] Hawaii Contract No. 65595. Scope of Services.

3 Current electricity rates in the State of Hawaii

In the State of Hawaii, as is typical of the electricity industry, electricity rates vary among different customer classes. The HECO Companies and KIUC have similar ratemaking procedures, including functionalization, classification, and allocation of costs necessary to render service, which then inform how rates are calculated for each customer classes. In each of the steps, appropriate bases and factors are developed based on detailed analysis and modeling.

3.1 Rate structure

Both HELCO and MECO have five rate classes, including "R" Residential, "G" Small Power Use Business, "J" Medium Power Use Business, "P" Large Power Use Business, and "F" Street Lighting. HECO, in addition, has another rate class called "DS" Large Power Directly Served Service. The descriptions of the applicability of each rate classes under HECO Companies are listed below:[5]

- Schedule "R" (Residential Service): *applicable to residential lighting, heating, cooking, air conditioning and power in a single-family dwelling unit metered and billed separately by the Company. This schedule does not apply where a residence and business are combined;*

- Schedule "G" (General Service Non-Demand): *applicable to general light and/or power loads less than or equal to 5000 kilowatt-hours per month, and less than or equal to 25 kilowatts, and supplied through a single meter;*

- Schedule "J" (General Service Demand): *applicable to general light and/or power loads which exceed 5000 kilowatt-hours per month or exceed 25 kilowatts three times within a twelve-month period but are less than 300 kilowatts per month, and supplied through a single meter*;

- Schedule "P" (Large Power Service): *applicable to large light and/or power loads equal or greater than 300 kilowatts, supplied and metered at a single voltage and delivery point;* and,

- Schedule "DS" (Large Power Directly Served Service):[6] *applicable to large light and/or power loads equal or greater than 300 kilowatts, supplied and metered at a single voltage and delivery point and served directly from a substation. Customers who are eligible for Schedule DS may elect to be served under any other schedule for which they are eligible.*

The HECO Companies' definitions of Schedule "F" are slightly different, as described below:

- Schedule "F" (HECO: Public Street Lighting, Highway Lighting and Park and Playground Floodlighting): *applicable only to public street and highway lighting, and public outdoor park and playground floodlighting service where the customer owns, maintains, and*

[5] HECO Companies. *Rate & Regulations*. Website. <https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/hawaiian-electric-rates>. Access Date: March 8, 2018.

[6] As mentioned above, the Schedule DS is only applicable to HECO (on the Island of Oahu).

operates the lighting fixtures and interconnecting circuits and conversion equipment. This rate applies to gaseous discharge lighting (Mercury Vapor) provided the regulator is corrected to power factor equivalent to the addition of one (1) KVAR of capacitors for each kW of nameplate rating of the regulator. Under this schedule energy shall be supplied and metered at a nominal voltage of 2400 volt or more, as specified by the Company, except as set forth below under Special Terms and Conditions;

- Schedule "F" (HELCO: Street Light Service): *applicable only to all-night service for street and highway lighting where the customer owns, maintains, and operates the lighting fixtures and all circuits and appurtenances on the customer's side of the delivery point. The service voltage shall be the available distribution voltage at the point of delivery;* and,

- Schedule "F" (MECO: Public Street Lighting): *applicable to public street and highway lighting service supplied on the Island of Maui / Lanai/ Molokai where the Company owns, maintains and operates the street lighting facilities.*

Similarly, KIUC has eight rate classes, including Schedule "D" Residential, Schedule "G" Small Commercial, Schedule "J" Large Commercial, Schedule "L" Large Power (Primary), Schedule "P" Large Power (Secondary), Schedule "NEM PILOT", Schedule "Q" Modified – Cogenerators, and Schedule "SL" Street Lighting. Among them, Schedule "NEM PILOT" and Schedule "Q" are energy credits payment rate to customers ($ per kWh). The thresholds that KIUC uses to separate the commercial rate classes are different from those of HECO Companies, as described below:[7]

- Schedule "G" (General Light & Power Service, Small Commercial): *not greater than 30 kW demand and 10,000 kWh use per month*;

- Schedule "J" (General Light & Power Service, Large Commercial): *greater than 30 kW and less than 100 kW demand or 10,000 kWh per month*;

- Schedule "L" (Large Power, Primary): *demand greater than 100 kW – metered on primary side of meter*; and,

- Schedule "P" (Large Power, Secondary): *demand greater than 100 kW – metered on secondary side of meter*.

For the HECO Companies, the current rates for Residential and Small Power Use Business are mainly based on energy consumption. In addition, there is a customer charge ($ per customer per month) and a Green Infrastructure Fee ($ per customer per month) added to all bills. In addition to these, rates for Medium Power Use Business, Large Power Use Business, and Large Power Use Business, Directly Served include a demand charge ($ per kW), as well.

[7] KIUC. *Energy Rate Adjustment Clause: Rate Data Sheet*. Effective Date: March 1, 2018. Website. <http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/rates/2018%20Rate%20Data.pdf>.

Moreover, the HECO Companies provide an optional Time-of-Use ("TOU") pilot rate program for Schedule R/ G/ J/ P rate classes.[8] This enables customers to save money if they shift their energy use away from high-demand on-peak hours that are at a higher rate.[9] The HECO Companies' average rates for each rate class in 2016 are shown in Figure 12.

Figure 12. HECO Companies: average price of electricity (2016 average cents/kWh)

Rate Schedule	HECO	HELCO	MECO			Average
			Maui	Molokai	Lanai	
"R" Residential	26.07	31.52	28.49	32.71	33.52	30.46
"G" Small Power Use Business	27.08	36.51	31.96	39.45	38.58	34.72
"J" Medium Power Use Business	22.03	27.65	27.37	31.26	35.86	28.83
"P" Large Power Use Business	20.15	24.28	24.81	24.68	31.91	25.17
"DS" Large Power Use Business, Directly Served	18.08	N/A	N/A	N/A	N/A	18.08
"F" Street and Park Lighting	22.96	31.08	25.66	30.00	32.65	28.47

Note: These numbers are derived by dividing the total revenue by the total kWh sold for each category during the year.
Source: HECO Companies. Rates and Regulations – Average price of electricity. Website. <https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/average-price-of-electricity>. Access Date: March 9. 2018.

Similarly, KIUC calculates rates based on customer charges and energy consumption for Residential and Small Commercial, but also includes a demand charge for Large Commercial and Large Power (Primary and Secondary). Moreover, KIUC also has a pilot TOU rate program for Residential and limited to approximately 300 residential customers who are duly selected to participate in the program.[10] Figure 13 shows KIUC's average rate for each rate class in 2016.

Figure 13. KIUC: average price of electricity (2016 average cents/kWh)

Rate Schedule	KIUC
Residential	34.03
Commercial	33.62
Large Power	30.06
Street Lighting	49.48
Irrigation	16.60

Note: These figures are derived by dividing the total revenue by the total kWh sold for each category during the year.
Source: KIUC. "KIUC Miscellaneous Data 2012-2016." Annual Report to the PUC (December 31, 2016). PDF page 47.

[8] Participation is voluntary. Only HELCO and MECO (not HECO) have Time-of-Use rate schedule for Schedule P.

[9] HECO Companies. *Time-of-Use Program*. Website. <https://www.hawaiianelectric.com/save-energy-and-money/time-of-use-program>. Access date: March 8, 2018.

[10] KIUC. *Schedule "TOU-S"*. Website. <http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/tariffs/tariff1-tou-s.pdf>. Access Date: March 8, 2018.

3.2 The HECO Companies' rate calculation methodology

Under the cost of service mechanism, the Public Utilities Commission ("PUC") determines the total annual revenues required by the utilities to cover both its expenses and the opportunity to earn a fair return on its investments. Then, each of the cost components of the revenue requirement is allocated to customer classes as a function of cost to provide service to each customer class.

The HECO Companies use a cost of service study tool to determine the cost responsibility of different rate classes for ratemaking purpose. There are two types of cost studies - one based on the embedded or accounting costs, and the other based on marginal energy costs. Both of them reflect the costs of providing service. However, the embedded cost of service study focuses on the categorization and allocation of total utility costs to various rate classes, while the marginal cost study determines the change in the utility's costs due to a unit change in kilowatts, kilowatt-hours or number of customers served by the utility.[11] Since the marginal cost study is less related to costs allocation among customer classes, the HECO Companies rely on an embedded cost of service study.

All the costs incurred in providing electric service to customers are incorporated in the embedded cost of service study, including the estimates of operation and maintenance expenses, depreciation expenses, taxes, plant costs, and return on capital.[12] Three major steps are involved in the embedded cost of service study methodology, as shown in Figure 14, namely:[13]

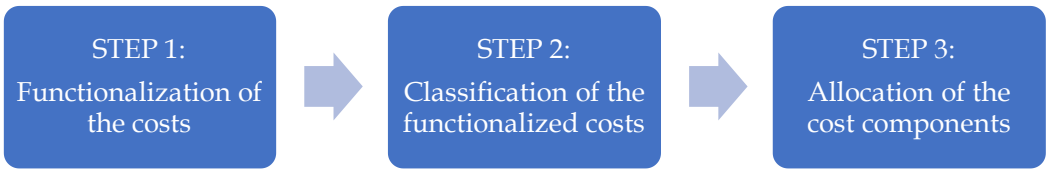
1. *functionalization of costs and rate base items into the major operating functions of production, transmission, and distribution;*

2. *classification of the functionalized costs into the three cost components of energy-related costs, demand-related costs, and customer-related costs; and,*

3. *allocation of the cost components to the different rate classes.*

Each step will be discussed in detail below.

Figure 14. Key steps in the cost of service study methodology



[11] HECO. "Cost of Service Studies". *HECO 2017 Test Year: Direct Testimonies and Exhibits Book 10*. Page 7-8.

[12] Ibid.

[13] Ibid, page 10.

3.2.1 Step 1: Functionalization of costs to production, transmission, and distribution functions

The costs are functionalized by using different methods. For some cost items, the HECO Companies use the National Association of Regulatory Utility Commissioners ("NARUC") Uniform System of Accounts.[14] For those costs associated with plant-in-service, most of the operation and maintenance expenses can be functionalized by account number analysis.[15] Other costs, including those related to general plant, administrative and general expenses, taxes, and return on capital, are not recorded by functional accounts and are not directly assigned to the major functions.[16] The HECO Companies categorize these general type costs by analyzing their characteristics or by using an appropriate functionalization base.[17]

Figure 15 illustrates the functionalization of costs for HECO, HELCO, and MECO by showing the NARUC Accounts in 2016. In general, administrative and general operations represent almost a third of costs, with production (operations and maintenance) generally being the other substantial costs category for the utilities.

Figure 15. Functionalization of costs: HECO, HELCO and MECO (O&M Expense by NARUC Account in 2016)

NARUC Account: HECO	Labor (Direct and On-cost)	% of Labor Total	Non-Labor (Direct and On-cost)	% of Non-Labor Total	Total = Labor + Non-Labor	% of Labor + Non-Labor Total
Production Operations	20,255,836	18.1%	17,843,502	18.1%	38,099,338	18.1%
Production Maintenance	16,026,407	14.3%	14,160,695	14.4%	30,187,102	14.3%
Transmission Operation	3,959,693	3.5%	3,516,725	3.6%	7,476,418	3.6%
Transmission Maintenance	2,889,938	2.6%	2,589,248	2.6%	5,479,186	2.6%
Distribution Operation	11,776,756	10.5%	10,353,455	10.5%	22,130,211	10.5%
Distribution Maintenance	6,489,207	5.8%	5,774,534	5.9%	12,263,741	5.8%
Customer Accounts	11,888,508	10.6%	10,060,958	10.2%	21,949,466	10.4%
Customer Services	5,485,670	4.9%	4,783,855	4.9%	10,269,525	4.9%
A&G Operation	32,998,793	29.5%	29,078,235	29.6%	62,077,028	29.5%
A&G Maintenance	238,575	0.2%	206,501	0.2%	445,076	0.2%
Grand Total	***112,009,383***	***100.0%***	***98,367,708***	***100.0%***	***210,377,091***	***100.0%***

[14] Ibid, page 12.

[15] Ibid, page 12.

[16] Ibid, page 12.

[17] Ibid, page 12.

NARUC Account: HELCO	Labor	% of Labor Total	Non-Labor	% of Non-Labor Total	Total = Labor + Non-Labor	% of Labor + Non-Labor Total
Production	9,422,884	49.9%	12,224,556	21.5%	21,647,440	28.5%
Transmission	1,733,146	9.2%	3,456,033	6.1%	5,189,179	6.8%
Distribution	3,390,208	17.9%	10,259,878	18.0%	13,650,086	18.0%
Customer Accounts	49,098	0.3%	9,476,008	16.6%	9,525,106	12.6%
Customer Services	409,449	2.2%	444,143	0.8%	853,592	1.1%
A&G	3,885,797	20.6%	21,091,376	37.0%	24,977,173	32.9%
Grand Total	***18,890,582***	***100.0%***	***56,951,994***	***100.0%***	***75,842,576***	***100.0%***

NARUC Account: MECO - Maui	Labor (Direct and On-cost)	% of Labor Total	Non-Labor (Direct and On-cost)	% of Non-Labor Total	Total = Labor + Non-Labor	% of Labor + Non-Labor Total
Production Operations	7,012,645	37.4%	5,208,193	12.1%	12,220,838	19.7%
Production Maintenance	4,488,968	23.9%	7,940,103	18.4%	12,429,071	20.1%
Transmission Operation	597,579	3.2%	955,073	2.2%	1,552,652	2.5%
Transmission Maintenance	340,552	1.8%	1,546,484	3.6%	1,887,036	3.0%
Distribution Operation	1,874,262	10.0%	1,858,444	4.3%	3,732,706	6.0%
Distribution Maintenance	1,597,243	8.5%	2,494,307	5.8%	4,091,550	6.6%
Customer Accounts	203,470	1.1%	5,505,920	12.8%	5,709,390	9.2%
Customer Services	423,851	2.3%	3,300,833	7.7%	3,724,684	6.0%
A&G Operation	2,211,479	11.8%	14,152,737	32.8%	16,364,216	26.4%
A&G Maintenance	16,998	0.1%	180,696	0.4%	197,694	0.3%
Grand Total	***18,767,047***	***100.0%***	***43,142,790***	***100.0%***	***61,909,837***	***100.0%***

NARUC Account: MECO - Lanai	Labor (Direct and On-cost)	% of Labor Total	Non-Labor (Direct and On-cost)	% of Non-Labor Total	Total = Labor + Non-Labor	% of Labor + Non-Labor Total
Production Operations	634,734	53.0%	364,164	25.2%	998,898	37.8%
Production Maintenance	353,810	29.5%	720,397	49.9%	1,074,207	40.7%
Transmission Operation	-	0.0%	-	0.0%	-	0.0%
Transmission Maintenance	-	0.0%	-	0.0%	-	0.0%
Distribution Operation	47,957	4.0%	39,389	2.7%	87,346	3.3%
Distribution Maintenance	61,967	5.2%	(31,820)	-2.2%	30,147	1.1%
Customer Accounts	91,989	7.7%	141,701	9.8%	233,690	8.8%
Customer Services	-	0.0%	271	0.0%	271	0.0%
A&G Operation	7,656	0.6%	208,642	14.5%	216,298	8.2%
A&G Maintenance	-	0.0%	-	0.0%	-	0.0%
Grand Total	***1,198,113***	***100.0%***	***1,442,744***	***100.0%***	***2,640,857***	***100.0%***

NARUC Account: MECO - Molokai	Labor (Direct and On-cost)	% of Labor Total	Non-Labor (Direct and On-cost)	% of Non-Labor Total	Total = Labor + Non-Labor	% of Labor + Non-Labor Total
Production Operations	687,676	61.7%	455,431	16.7%	1,143,107	29.8%
Production Maintenance	190,935	17.1%	922,540	33.9%	1,113,475	29.0%
Transmission Operation	11,256	1.0%	25,823	0.9%	37,079	1.0%
Transmission Maintenance	-	0.0%	46,822	1.7%	46,822	1.2%
Distribution Operation	50,445	4.5%	50,381	1.8%	100,826	2.6%
Distribution Maintenance	137,739	12.4%	378,221	13.9%	515,960	13.4%
Customer Accounts	29,302	2.6%	354,791	13.0%	384,093	10.0%
Customer Services	-	0.0%	2,691	0.1%	2,691	0.1%
A&G Operation	1,404	0.1%	451,841	16.6%	453,245	11.8%
A&G Maintenance	5,326	0.5%	35,577	1.3%	40,903	1.1%
Grand Total	***1,114,083***	***100.0%***	***2,724,118***	***100.0%***	***3,838,201***	***100.0%***

Note: A&G stands for "Administration and General"

Source: HECO. 2017 Test Year Rate Case (Docket 2016-0328). O&M Expense by Account Block by NARUC Account. HECO-WP-201C. Page 4 of 12. HELCO. 2016 Test Year Rate Case (Docket 2015-0170). O&M Expense by NARUC Account. HELCO-WP-101. Page 4 of 8. MECO. 2018 Test Year Rate Case (Docket 2017-0150). O&M Expense by Island by Block of Accounts by NARUC Account. MECO-WP-101. Page 9 of 10.

3.2.2 Step 2: Classification of functionalized costs into energy-, demand-, and customer-related costs

Then, functionalized costs are further classified based on what causes them to be incurred. This helps to facilitate the allocation to the various rate classes based on measurable service characteristics, such as kWh consumption, kW demand, and number or type of customers connected to the system.[18] Other costs that are not directly associated with these measurements, such as taxes, are related to revenues or payroll. The HECO Companies allocate revenue-related costs directly to the various rate classes based on the revenues generated from each rate class or by the allocated O&M labor expense.[19] Following the NARUC utility cost allocation rationale, the production function costs are classified into demand and energy components; the transmission function costs are classified to demand components; and the distribution function costs are classified to demand and customer components.[20]

Figure 16 summarizes the ratios of costs allocated to demand, energy, and customer for each utility in HECO Companies most recent proposed rate cases. The repartition varies somewhat between the different utilities, reflecting the different mixes of customer types in the counties of Hawaii State.

Figure 16. Ratios of costs allocated to demand, energy, and customer for HECO, HELCO, and MECO (based on Minimum System Method)

HECO	Demand Costs	Energy Costs	Customer Costs	Total Costs
Schedule R	20.42%	22.14%	71.90%	26.38%
Schedule G	5.17%	4.66%	12.44%	5.64%
Schedule J	31.64%	28.37%	14.29%	28.31%
Schedule DS	15.69%	18.83%	0.12%	15.68%
Schedule P	26.38%	25.48%	1.13%	23.43%
Schedule F	0.71%	0.52%	0.13%	0.55%

HELCO	Demand Costs	Energy Costs	Customer Costs	Total Costs
Schedule R	30.34%	35.07%	71.32%	37.98%
Schedule G	10.49%	8.70%	18.72%	10.96%
Schedule J	35.47%	31.37%	7.49%	29.92%
Schedule P	23.22%	24.46%	2.22%	20.72%
Schedule F	0.48%	0.40%	0.25%	0.41%

[18] Ibid, page 12.

[19] Ibid, page 12.

[20] Ibid, page 13 - 14.

MECO - Maui	Demand Costs	Energy Costs	Customer Costs	Total Costs
Schedule R	25.73%	32.00%	56.12%	33.42%
Schedule G	7.79%	7.53%	14.79%	8.64%
Schedule J	30.08%	26.30%	18.28%	26.37%
Schedule P	36.28%	33.78%	9.92%	31.19%
Schedule F	0.12%	0.39%	0.90%	0.37%

MECO - Lanai	Demand Costs	Energy Costs	Customer Costs	Total Costs
Schedule R	22.65%	26.60%	46.26%	26.74%
Schedule G	5.35%	5.13%	13.70%	5.85%
Schedule J	30.45%	25.35%	19.12%	26.60%
Schedule P	44.01%	42.69%	7.67%	40.51%
Schedule F	-2.45%	0.23%	13.25%	0.30%

MECO - Molokai	Demand Costs	Energy Costs	Customer Costs	Total Costs
Schedule R	29.55%	33.03%	52.92%	34.01%
Schedule G	20.28%	13.05%	19.87%	15.92%
Schedule J	33.56%	29.52%	15.62%	29.32%
Schedule P	15.95%	23.03%	8.46%	19.42%
Schedule F	0.65%	1.37%	3.13%	1.32%

Note: These numbers are rounded so the total may not equal to 100.00%.

Source: HECO. 2017 Test Year Rate Case (Docket 2016-0328). Summary of Cost Components By Rate Class at Proposed Rates, Cost of Service at Proposed Based on Minimum System Method, Base Case – No Schofield Generation Station. HECO-3003. Page 2 of 4. HELCO. 2016 Test Year Rate Case (Docket 2015-0170). Summary of Cost Components By Rate Class at Proposed Rates, Cost of Service at Proposed Based on Minimum System Method, HEP IPP-Owned at Proposed. HELCO-2203. Page 2 of 4. MECO. 2018 Test Year Rate Case (Docket 2017-0150). Summary of Cost Components By Rate Class at Proposed Rates, Cost of Service at Proposed Based on Minimum System Method, With Existing Depreciation Rates. MECO-2303/2305/2037. Page 2 of 4.

3.2.3 Step 3: Allocation of the cost components to the different rate classes

Allocation factors, including energy allocation factors, demand allocation factors, customer-related costs allocation factors, are used in the third step. HECO, HELCO, and MECO use the same categories of allocation factors as shown in Figure 17 below.

Figure 17. Allocation factors for HECO, HELCO, and MECO (based on Minimum System Method, unit: %)

HECO	Schedule R	Schedule G	Schedule J	Schedule DS	Schedule P	Schedule F	Total
Demand Allocation Factors:							
Average-Excess Demand	25.006	5.699	27.879	16.984	23.736	0.696	100.000
Class Peak Demand	30.391	6.978	33.4560	0.0000	28.317	0.858	100.000
Composite NCD	44.020	7.559	31.449	0.000	16.880	0.092	100.000
Energy Allocation Factors:							
Gross Input	22.370	4.690	28.307	18.686	25.422	0.525	100.000
Customer Allocation Factors:							
Primary Lines	84.119	11.069	4.455	0.000	0.225	0.132	100.000
Secondary Lines	87.454	9.288	3.080	0.000	0.155	0.023	100.000
Transformers	32.642	39.777	24.218	0.000	3.363	0.000	100.000
Services	87.950	8.455	2.932	0.387	0.201	0.075	100.000
Meter	72.329	9.502	16.612	0.098	0.797	0.662	100.000
Cust Acct Fct	86.102	9.954	3.605	0.014	0.179	0.146	100.000
Bad Debt	55.450	12.010	19.770	0.000	12.770	0.000	100.000
Cust Serv Fct	64.710	5.011	28.814	0.110	1.268	0.087	100.000
Avg Cust	88.900	8.356	2.465	0.011	0.129	0.139	100.000

HELCO	Schedule R	Schedule G	Schedule J	Schedule P	Schedule F	Total
Demand Allocation Factors:						
Average-Excess Demand	35.889	8.709	31.052	23.932	0.417	100.000
Class Peak Demand	43.900	9.277	28.475	17.750	0.599	100.000
Composite NCD	55.482	9.923	26.249	7.901	0.445	100.000
Energy Allocation Factors:						
Gross Input	35.245	8.664	31.26	24.429	0.402	100.000
Customer Allocation Factors:						
Primary Lines	80.371	15.805	3.401	0.204	0.218	100.000
Secondary Lines	83.096	14.118	2.420	0.141	0.225	100.000
Transformers	77.810	16.525	4.709	0.744	0.211	100.000
Services	80.059	16.121	3.370	0.232	0.217	100.000
Meter	68.801	13.638	15.091	2.284	0.187	100.000
Cust Acct Fct	79.828	16.023	3.636	0.238	0.274	100.000
Bad Debt	64.150	14.680	11.000	10.160	0.010	100.000
Cust Serv Fct	21.410	9.463	37.137	31.940	0.050	100.000
Avg Cust	84.456	13.286	1.922	0.107	0.229	100.000

MECO - Maui Division	Schedule R	Schedule G	Schedule J	Schedule P	Schedule F	Total
Demand Allocation Factors:						
Average-Excess Demand	37.391	9.530	24.865	27.548	0.665	100.000
Class Peak Demand	36.928	9.346	25.047	28.040	0.639	100.000
Composite NCD	49.821	9.033	25.272	15.302	0.572	100.000
Energy Allocation Factors:						
Gross Input	32.232	7.564	26.234	33.575	0.395	100.000
Customer Allocation Factors:						
Primary Lines	79.753	15.35	4.223	0.369	0.305	100.000
Secondary Lines	83.497	12.902	3.025	0.257	0.319	100.000
Transformers	77.757	16.863	5.071	0.013	0.297	100.000
Services	70.611	10.241	17.593	1.285	0.270	100.000
Meter	83.029	12.154	2.846	1.653	0.317	100.000
Cust Acct Fct	78.760	14.518	5.804	0.604	0.314	100.000
Bad Debt	71.070	17.350	11.560	0.000	0.020	100.000
Cust Serv Fct	21.410	14.240	32.360	31.940	0.050	100.000
Avg Cust	85.503	11.589	2.383	0.198	0.327	100.000

MECO - Lanai Division	Schedule R	Schedule G	Schedule J	Schedule P	Schedule F	Total
Demand Allocation Factors:						
Average-Excess Demand	32.152	5.285	23.490	38.616	0.456	100.000
Class Peak Demand	32.688	5.301	23.324	38.216	0.471	100.000
Composite NCD	53.035	6.006	28.780	11.737	0.443	100.000
Energy Allocation Factors:						
Gross Input	26.965	5.133	25.097	42.492	0.313	100.000
Customer Allocation Factors:						
Primary Lines	82.110	12.539	4.804	0.328	0.218	100.000
Secondary Lines	84.381	11.664	3.507	0.224	0.224	100.000
Transformers	81.645	12.791	5.347	0.000	0.217	100.000
Services	69.127	9.374	20.246	1.069	0.184	100.000
Meter	74.164	14.352	9.443	1.843	0.197	100.000
Cust Acct Fct	79.747	13.239	6.318	0.477	0.219	100.000
Bad Debt	99.810	0.180	0.010	0.000	0.000	100.000
Cust Serv Fct	21.410	14.235	32.365	31.940	0.050	100.000
Avg Cust	85.503	11.256	2.843	0.171	0.227	100.000

MECO - Molokai Division	Schedule R	Schedule G	Schedule J	Schedule P	Schedule F	Total
Demand Allocation Factors:						
Average-Excess Demand	36.663	13.119	23.656	24.725	1.837	100.000
Class Peak Demand	37.089	13.140	22.967	24.913	1.892	100.000
Composite NCD	42.674	12.851	21.937	21.203	1.335	100.000
Energy Allocation Factors:						
Gross Input	33.158	12.946	29.333	23.182	1.381	100.000
Customer Allocation Factors:						
Primary Lines	78.348	16.657	4.151	0.582	0.262	100.000
Secondary Lines	81.653	14.668	3.002	0.403	0.273	100.000
Transformers	76.757	17.964	5.023	0.000	0.256	100.000
Services	68.346	11.827	17.612	1.986	0.228	100.000
Meter	66.599	21.623	8.388	3.167	0.222	100.000
Cust Acct Fct	76.880	16.445	5.521	0.888	0.266	100.000
Bad Debt	99.680	0.320	0.000	0.000	0.000	100.000
Cust Serv Fct	5.000	15.000	40.000	40.000	0.000	100.000
Avg Cust	83.277	13.725	2.411	0.309	0.278	100.000

Note: "NCD" stands for Non-Coincident Demand
Source: HECO. 2017 Test Year Rate Case (Docket 2016-0328). Cost of Service at Proposed Based on Minimum System Method. HECO-3003. Page 4 of 4. HELCO. 2016 Test Year Rate Case (Docket 2015-0170). Cost of Service at Proposed Based on Minimum System Method HEP IPP-Owned at Proposed. HELCO-2203. Page 4 of 4. MECO. 2018 Test Year Rate Case (Docket 2017-0150). Cost of Service at Proposed Based on Minimum System Method With Existing Depreciation Rates. MECO-2303/2305/2037. Page 4 of 4.

For demand cost allocation, there are three main methods, including Average-Excess Demand Method ("AED Method"), Peak Responsibility Method ("PR Method"), and Non-Coincident Demand Method ("NCD Method"). The HECO Companies use the AED Method to allocate the production and transmission demand costs, as it considers the "*classes' demand requirements, energy consumption, and system load factor in allocating the demand costs*, and thereby results in *more stable results*."[21] But for the distribution demand costs, HECO Companies use the NCD Method as "*the distribution facilities are sized to serve the maximum diversified demand at these services levels regardless of the system peak load*."[22]

The energy allocation factors are based on the kWh sales forecasts for each rate class and adjusted for line losses.[23]

Customer-related costs are determined by the number and/or type of customers. The weighting factors reflect differences in "*service phase, service voltage, metering requirements, and complexity of meter reading, billing, and accounting services.*"[24]

Finally, the allocation factors are used to allocate each cost component to the different rate classes. The demand allocation factor is used to allocate demand-related cost components to the different rate classes based on the kW demand of each class. The energy allocation factor is used to allocate energy-related cost component to the different rate classes based on the classes' kWh

[21] Ibid, page 17.

[22] Ibid, page 18.

[23] Ibid, page 15.

[24] Ibid, page 15.

consumption. The customer allocation factor is used to allocate customer-related cost component to different rate classes based on "*the number of customers in each rate class, weighted to reflect the differences in various customer-related services and/or activities*."[25]

As a result, HECO Companies proposed an equal percentage increase in revenues at current effective rates for each rate class in its filings.[26]

3.3 KIUC's rate calculation methodology

KIUC uses the embedded cost approach (same as the HECO Companies) for the cost of service analysis, including the functionalization, classification, and allocation of revenue requirement.

In the functionalization process, the components of revenue requirement were assigned to production, transmission or distribution functions. For instance, in the test year 2010, revenue requirement was 71% production-related, 7% transmission-related, and 22% distribution-related.[27]

Then, in the classification process, the functionalized revenue requirement is further divided into demand-related, energy-related, and customer-related categories. The approach is consistent with the framework in January 1992 *NARUC Electric Utility Cost Allocation Manual* ("NARUC Manual"). Based on the approach in the NARUC Manual, production-related costs are either classified as demand-related or energy-related costs. Demand-related costs are further classified into base demand-related and peak demand-related costs. The ratios for classification are determined based on an analysis of each unit's projected operation during test year. For instance, in the test year 2010, the fixed demand-related costs for the steam generator at the Port Allen plant were classified 69% to base demand and 31% to peak demand;[28] the capital investment costs for the Stork-Wartsila diesel generators (Units 6-9) at the Port Allen plant were classified 53% to base demand and 47% to peak demand; while the breakdown of total capital investment costs for other units was 68% base demand and 32% peak demand.[29] Transmission-related costs are all classified as base demand-related, and all distribution network costs are classified as demand-related, while some distribution costs related to service drops, meters, customer accounts, etc. are classified as customer-related. In all, revenue requirement for the test year 2010 was 48% demand-

[25] Ibid, page 15.

[26] Ibid, page 10; HELCO. *2016 Test Year Rate Case (Docket 2015-0170) Book 8*. Executive Summary. PDF page 330; MECO. *2018 Test Year Rate Case (Docket 2017-0150) Book 9*. Executive Summary. PDF page 170.

[27] Ibid, PDF page 224.

[28] Ibid, PDF page 225.

[29] Ibid, PDF page 226.

related, 45% energy-related, and 7% customer-related.[30] Figure 18 summarizes the functionalization and classification of Cost of Service for KIUC in 2010.

Figure 18. KIUC functionalization and classification of the cost of service (2010)

Description	Demand	%	Energy	%	Customer	%	Total	%
Production	$ 35,268,510	36%	$ 61,774,224	64%	$ -	0%	$ 97,042,734	100%
Transmission	$ 9,875,574	100%	$ -	0%	$ -	0%	$ 9,875,574	100%
Distribution	$ 20,773,114	69%	$ -	0%	$ 9,396,373	31%	$ 30,169,487	100%
Total Cost of Service	***$ 65,917,198***	***48%***	$ 61,774,224	***45%***	$ 9,396,373	***7%***	$137,087,795	***100%***

Note: The Project Team found the 2010 cost of service functionalization and classification data as the most updated one that is publicly available

Source: KIUC. Exhibit KIUC 10: Testimony of Robert L. O'Brien (Docket No. 2009-0050, Volume 2). PDF page 254.

Finally, in the allocation process, classified portions of the revenue requirement are allocated to customer classes. The average and excess demand method or non-coincident peak method is used to allocate demand-related costs. Energy-related production costs are allocated on a per-kWh basis. And customer-related costs are "*either directly assigned to customer classes or allocated to customer classes based on the number of customers or weighted number of customers in each class.*"[31] To allocate demand-related costs, the average and excess demand method is used for allocating demand-related production and transmission costs, while the non-coincident peak method is used for allocating demand-related distribution costs.[32] The demand allocation factors are calculated using each customer class' projected average demand level and non-coincident peak demand level. The load analysis is also used to develop the energy allocation factors which represent customer classes' projected share of annual energy sold and adjusted for an allocation of expected system losses in a test year.

Figure 19 shows the allocation factors that were developed based on both coincident and non-coincident peak demand levels for each of KIUC customer classes. Customer allocation factors consist of two types – unweighted customer allocation factor, and weighted customer allocation factor. The unweighted factor is developed based on the projected number of customers in each class, while the weighted factor is an adjustment to the unweighted factor for the relative service level requirements for each customer class. The weighted customer allocation factors are used for the costs of meters, meter operating and maintenance costs, customer programs, and meter reading costs, etc.[33] As a result, the revenue requirement of the test year 2010 allocated to each customer class is shown in Figure 20.

[30] Ibid, PDF page 227.

[31] Ibid, PDF page 227.

[32] Ibid, PDF page 228.

[33] Ibid, PDF page 229.

Figure 19. KIUC allocation factors (2010)

Allocation Factor	Res (D)	General L&P (G)	General L&P (J)	Large Power (P)	Large Power (L)	Irrigation	Street Lighting	Total
CP	42.3%	13.1%	11.4%	23.5%	9.1%	0.0%	0.7%	100%
6CP	44.5%	12.6%	10.9%	21.9%	9.1%	0.3%	0.7%	100%
12CP	44.3%	12.5%	10.8%	21.9%	9.5%	0.4%	0.7%	100%
NCP	41.0%	14.4%	11.8%	19.3%	8.1%	5.0%	0.5%	100%
6NCP	41.5%	15.2%	11.8%	19.4%	8.3%	3.3%	0.6%	100%
12NCP	42.0%	15.3%	11.9%	19.5%	8.5%	2.2%	0.6%	100%
Energy Sales	35.4%	13.6%	12.7%	26.0%	11.5%	0.3%	0.6%	100%
Energy Requirement	35.4%	13.6%	12.7%	26.1%	11.4%	0.3%	0.6%	100%

Note: "CP" stands for coincident peak, "NCP" stands for non-coincident peak.
Source: KIUC. Exhibit KIUC 10: Testimony of Robert L. O'Brien (Docket No. 2009-0050, Volume 2). PDF page 206.

Figure 20. Revenue requirement allocation to each customer class (2010)

Schedule D	Schedule G	Schedule J	Schedule P	Schedule L	Schedule SL	Irrigation
Residential	General Light and Power Service	General Light and Power Service	Large Power Secondary Service	Large Power Primary Service	Street Lighting Schedule	Irrigation
41%	14%	12%	22%	9%	1%	1%

Source: KIUC. Exhibit KIUC 10: Testimony of Robert L. O'Brien (Docket No. 2009-0050, Volume 2). PDF page 230.

3.4 Role of Hawaii PUC in ratemaking

According to the Hawaii Revised Statues Chapter 269-16, all rates, schedules, rules, and practices made or charged by public utilities shall be filed with the Hawaii PUC. The PUC is required to issue its decision as expeditiously as possible, and before nine months from the date, the public utility filed its completed application.[34] As part of the regulatory framework, the PUC has adopted the cost of service mechanism, decoupling mechanism, and earnings sharing mechanism. These mechanisms will be further explained and examined in Task 2 Regulatory Models and Task 3 Additional Analyses. It is worth noting that the rate design methodology described above was included and approved by the PUC in the most recent rate cases of KIUC (Docket 2009-0050), HECO (Docket 2016-0328) and HELCO (Docket 2015-0170).[35]

[34] HRS 269-16.

[35] Interim rate order approved for HELCO. Revised one-step interim rate increase authorized, effective 2/16/18 for HECO.

4 Forecast of electricity rates under various ownership models

In order to calculate the electricity rates under the different ownership models through to 2045, the Project Team relied on the load forecast for the various counties (Task 1.5.2) as well as the revenue requirement forecast for each county under the different ownership models (Task 1.6.3). Furthermore, the Project Team used the historical cost allocation factors, reflected in historical average rates for each utility and customer class, to estimate future rates for typical residential, commercial, and large power users.

4.1 Methodology to estimate future rates

The Project Team first used historical 2016 data from the utilities' annual reports to the PUC to calculate the ratios of electricity sales, electricity revenues, and number of customers per customer class for each of the utilities in the State of Hawaii, as illustrated in Figure 22.

- The electricity sales ratio represents the share of electricity sales (in MWh) for each customer class;
- The electricity revenues ratio represents the share of electricity revenues (in dollars) for each customer class; and
- The average number of customers ratio represents the ratio of customers for each customer class.

As a first step, the Project Team divided the load forecast for each utility into a forecast of energy sales for each class of customer. In order to do this, the Project Team applied the historical electricity sales ratios per customer class illustrated in Figure 22 to the load forecast for each utility that was created as part of Task 1.5.2.

As a second step, the Project team divided the forecast of revenue requirements for each county and each ownership model into revenue requirements for each class of customer. For this task, the Project Team used the electricity revenues ratios illustrated in Figure 22.

Figure 21. Elements of estimated projected rates

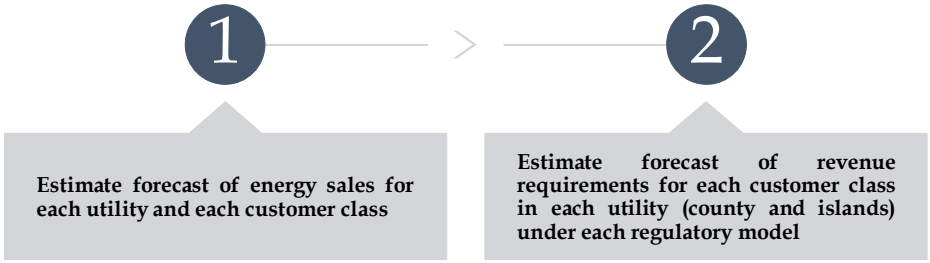


Figure 22. Historical distribution of electricity sales, electricity revenues, and the average number of customers per customer classes for utilities in the State of Hawaii

Customer class	HECO			HELCO		
	Electricity sales ratio	Electricity revenues ratio	Avg. nb. of customers ratio	Electricity sales ratio	Electricity revenues ratio	Avg. nb. of customers ratio
Residential	23.7%	28.1%	88.9%	36.2%	39.3%	84.5%
Commercial	32.0%	33.0%	10.6%	39.3%	40.1%	15.1%
Large Power	43.7%	38.3%	0.1%	24.2%	20.3%	0.1%
Other	0.5%	0.6%	0.4%	0.3%	0.3%	0.2%

Customer class	MECO - Maui Island			MECO - Lanai Island		
	Electricity sales ratio	Electricity revenues ratio	Avg. nb. of customers ratio	Electricity sales ratio	Electricity revenues ratio	Avg. nb. of customers ratio
Residential	32.9%	33.6%	85.5%	25.2%	26.7%	85.6%
Commercial	31.8%	35.2%	14.0%	29.4%	32.7%	14.0%
Large Power	34.8%	30.9%	0.2%	45.0%	40.3%	0.2%
Other	0.5%	0.4%	0.3%	0.4%	0.3%	0.2%

Customer class	MECO - Molokai Island			KIUC		
	Electricity sales ratio	Electricity revenues ratio	Avg. nb. of customers ratio	Electricity sales ratio	Electricity revenues ratio	Avg. nb. of customers ratio
Residential	35.5%	34.1%	83.2%	37.3%	39.1%	77.2%
Commercial	43.3%	45.5%	16.2%	25.8%	26.7%	12.5%
Large Power	19.2%	19.1%	0.3%	36.3%	33.4%	0.3%
Other	2.0%	1.3%	0.3%	0.6%	0.9%	9.9%

Notes: The electricity sales, electricity revenues, and average number of customers ratios are based on 2016 values for the HECO Companies and KIUC, with the exception of MECO revenue ratios by island due to unavailability of information. Consequently, the electricity revenues ratios for the three islands (i.e., Maui, Lanai, Molokai) were estimated based on 2018 electric revenues by island at present rates. Therefore, it is assumed that 2016 revenue ratios by rate class were approximately equivalent to the revenue ratios by rate class in 2018; Nb = Number.

Source: HECO, HELCO, MECO, and KIUC annual reports to the PUC; MECO 313, 402 Docket No. 2017-0150.

4.2 Forecast of rates

Using the annual revenue requirement per customer class calculated in step one, divided by the annual electricity sales per customer class calculated in step two, the Project Team created estimates of average electricity rates per customer class for each utility and each ownership model. The resulting rates are illustrated in Figure 23 through Figure 40 for HECO, HELCO, MECO, and KIUC.

Of note is that rates follow the pattern of growth in overall revenue requirement for each utility and ownership model, but do not grow as fast as the revenue requirement given the flat to moderate growth in load and number of customers. Further, the differences in rates between ownership models are driven by the differences in revenue requirements, as load forecasts do not vary between the models.

Finally, in order to illustrate the impact of rate changes on the customers, the Project Team calculated average customer charges for each customer class, county, and ownership model by dividing the appropriate revenue requirement by the average number of customers in each class.

4.2.1 HECO

The SB models are expected to provide slightly lower average electricity rates in Honolulu County, while the co-op is anticipated to have higher average electricity rates than the IOU. Over the forecast horizon, average rates for HECO residential customers in Honolulu County are anticipated to range from 28.1 cents/kWh under the SB models, to 28.3 and 29.8 cents/kWh respectively for the IOU and co-op models. Commercial and large power rates are similarly impacted, with the SB model showing lower average rates than the other models, and the co-op mode3l resulting in the highest rates. These results are illustrated in Figure 23.

Note that in order to calculate these average rates over the forecast horizon, the Project Team converted the forecast rates from nominal dollars into constant 2017 dollars, before averaging all values over the forecast horizon (i.e., 2018 to 2045).

Figure 23. Projected average rates over forecast horizon in Honolulu County for each ownership model

2017 cents/kWh	IOU	Co-op	SB (outside)	SB (inside)
Residential	28.3	29.8	28.1	28.1
Commercial	24.7	26.0	24.5	24.5
Large power	21.0	22.1	20.8	20.8
Other	25.8	27.2	25.6	25.6

Similarly, Figure 24 illustrates the average impact, over the forecast horizon and considering the average consumption of each class of customer that the various ownership models would have on monthly customer bills. These figures are shown in constant 2017 dollars.

Figure 24. Projected average monthly bill over forecast horizon in Honolulu County for each ownership model

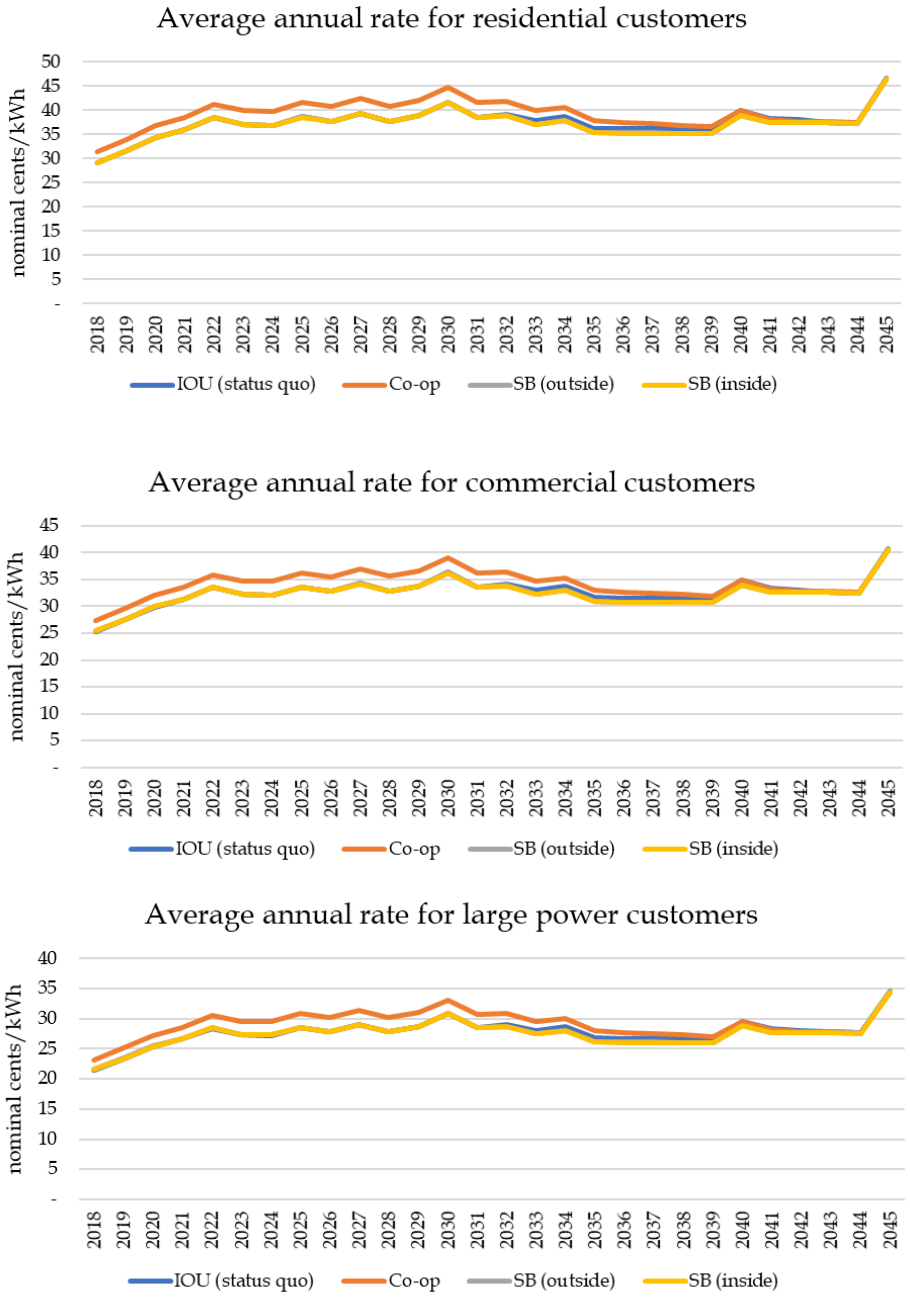
2017 dollars	IOU	Co-op	SB (outside)	SB (inside)
Residential	$ 121	$ 127	$ 120	$ 120
Commercial	$ 1,188	$ 1,253	$ 1,180	$ 1,179
Large power	$ 102,588	$ 108,190	$ 101,880	$ 101,837
Other	$ 576	$ 608	$ 572	$ 572

The trends in projected average annual rates under various ownership models are similar for residential, commercial, and large power customers in Honolulu County in that they show a general increasing trend throughout the forecast horizon. The average year-on-year growth in forecasted average annual rates for all three customer types from 2018 is 2.0%, 2.0%, 1.9%, and 1.9% for the IOU, co-op, SB (outside), and SB (inside) models, respectively.[36] Figure 25 illustrates

[36] Note that in order to calculate these average growth rates over the forecast horizon, the Project Team calculated the annual growth rates between all years through to 2045, before averaging all values over the forecast horizon.

the trend in rates for residential, commercial, and large power customers in Honolulu County (values are in nominal dollars).

Figure 25. Projected average annual rates forecast for HECO under various ownership models



4.2.2 HELCO

In Hawaii County, the IOU is expected to have the lowest average rates across all the customer classes, although the SB models are not too far behind. Over the forecast horizon, average rates

for HELCO residential customers in Hawaii County are anticipated to be on approximately the same level under the IOU and SB models at around 37.8 to 37.9 cents/kWh, respectively, and slightly higher at 40.9 cents/kWh for the co-op model. Commercial and large power rates are similarly impacted, with the IOU and SB models showing lower average rates, and the co-op model resulting in the highest rates. These results are illustrated in Figure 26.

Note that to calculate these average rates over the forecast horizon, the Project Team converted the forecast rates from nominal dollars into constant 2017 dollars, before averaging all values over the forecast horizon.

Figure 26. Projected average rates over forecast horizon in Hawaii County for each ownership model

2017 cents/kWh	IOU	Co-op	SB (outside)	SB (inside)
Residential	37.8	40.9	37.9	37.9
Commercial	35.4	38.3	35.5	35.5
Large power	29.1	31.5	29.2	29.2
Other	37.3	40.4	37.4	37.4

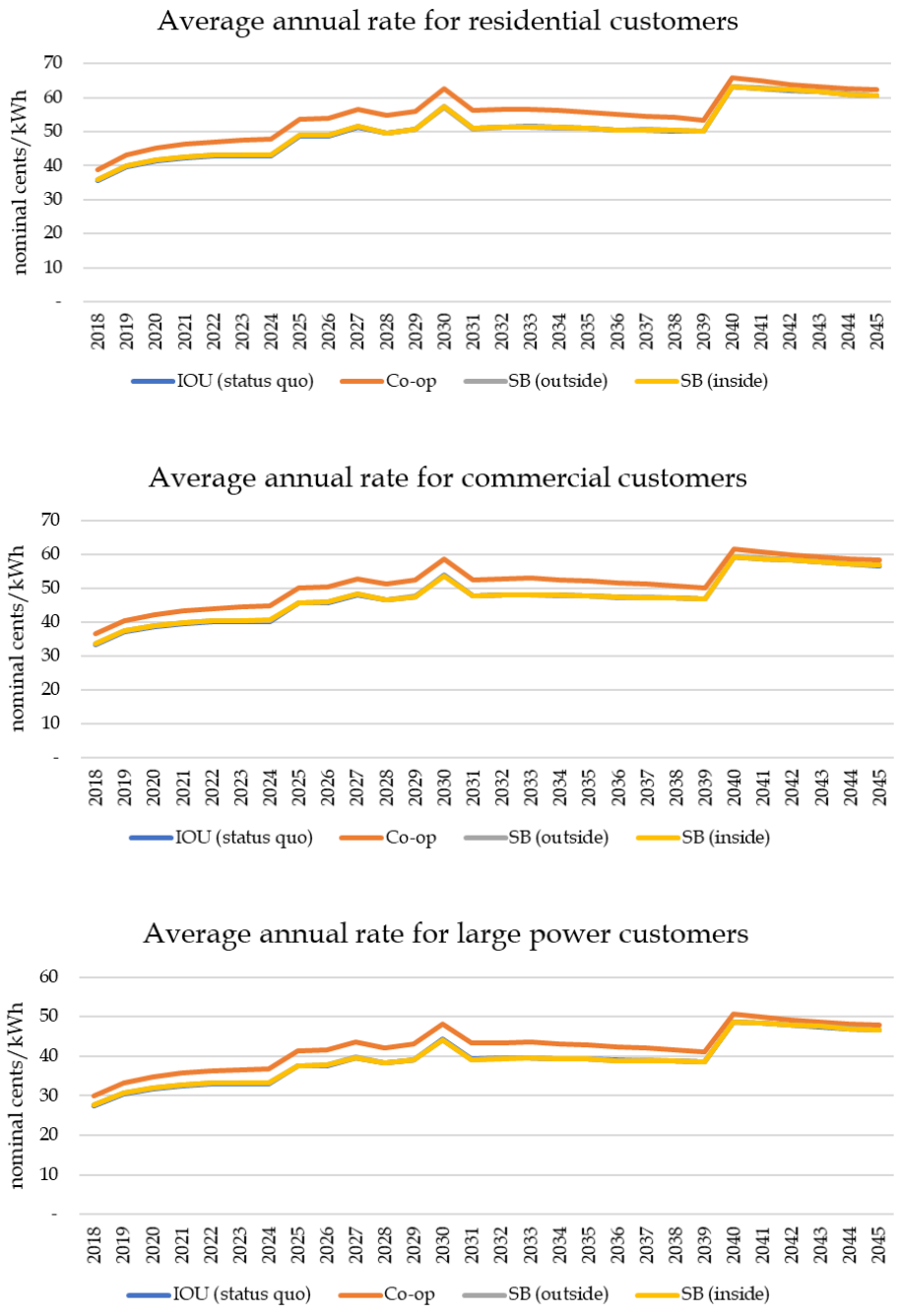
Similarly, Figure 27 illustrates the average impact, over the forecast horizon and considering the average consumption of each class of customer, that the various ownership models would have on monthly customer bills. These figures are shown in constant 2017 dollars.

Figure 27. Projected average monthly bill over forecast horizon in Hawaii County for each ownership model

2017 dollars	IOU	Co-op	SB (outside)	SB (inside)
Residential	$ 139	$ 151	$ 140	$ 140
Commercial	$ 791	$ 856	$ 793	$ 793
Large power	$ 56,406	$ 61,061	$ 56,563	$ 56,565
Other	$ 443	$ 480	$ 444	$ 444

Overall, the trends in projected average annual rates under various ownership models are similar for residential, commercial, and large power customers in Hawaii County in that they show a general increasing trend throughout the forecast horizon. The average year-on-year growth in forecasted average annual rates for all three customer types from 2018 through 2045 are 2.2%, 1.9%, 2.2%, and 2.2% for the IOU, co-op, SB (outside), and SB (inside) models, respectively. Figure 28 illustrates the trend in rates for residential, commercial, and large power customers in Hawaii County (values are in nominal dollars).

Figure 28. Projected average annual rates forecast for HELCO under various ownership models



4.2.3 MECO

For Maui County, the Project Team conducted separate analyses to evaluate the impact on rates from ownership change on both a county-wide basis and separately for each island (Maui, Lanai, and Molokai). A county-wide change in ownership model would result in a single SB, whether

within or outside the utility, for all three islands. The Team allocated the costs associated with the SB's operations to each island based on their current share of MECO's rate base. However assuming an ownership change by island, the Team assumed that an SB would be established on each island. For the transition to a co-op model, there was no difference between the two approaches since MECO's acquisition cost was allocated to each island in the same proportion under both approaches.

4.2.3.1 Maui

On the island of Maui, the SB models are anticipated to provide the lowest average rates for residential, commercial, and large power users for all the islands. The Team projects this to be the case whether the transition to a new ownership model happens by island or at a county-wide level. Island-specific vs. county-wide transition do not impact the forecasted rates under the co-op model because the acquisition costs are assumed to be the same regardless.

Due to the large size of the island of Maui relative to Lanai and Molokai, an island-by-island transition and county-wide transition are both expected to have similar impact on rates on Maui island. More specifically, the average rates for residential customers under the SB models after an island-specific transition are around 30.9 cents/kWh; after a county-wide transition, average residential rates are around 30.8 cents/kWh under an independent SB model and 30.5 cents/kWh under a ring-fenced SB. Average rates are slightly higher at 31.3 cents/kWh and 30.7 cents/kWh for the IOU and co-op models, respectively. Commercial and large power rates are similarly impacted, with the SB models showing lower average rates, and the IOU and co-op models resulting in slightly higher average rates. These results are illustrated in Figure 29.

Note that in order to calculate these average rates over the forecast horizon, the Project Team converted the forecast rates from nominal dollars into constant 2017 dollars, before averaging all values over the forecast horizon.

Figure 29. Projected average rates over forecast horizon on the island of Maui for each ownership model

2017 cents/kWh	IOU	Co-op	SB (outside)	SB (inside)
		MECO-wide transition		
Residential	31.3	30.7	30.8	30.5
Commercial	34.0	33.3	33.5	33.1
Large power	27.2	26.7	26.9	26.6
Other	21.7	21.3	21.4	21.2
		Island-specific transition		
Residential	31.3	30.7	30.9	30.9
Commercial	34.0	33.3	33.5	33.5
Large power	27.2	26.7	26.9	26.9
Other	21.7	21.3	21.4	21.4

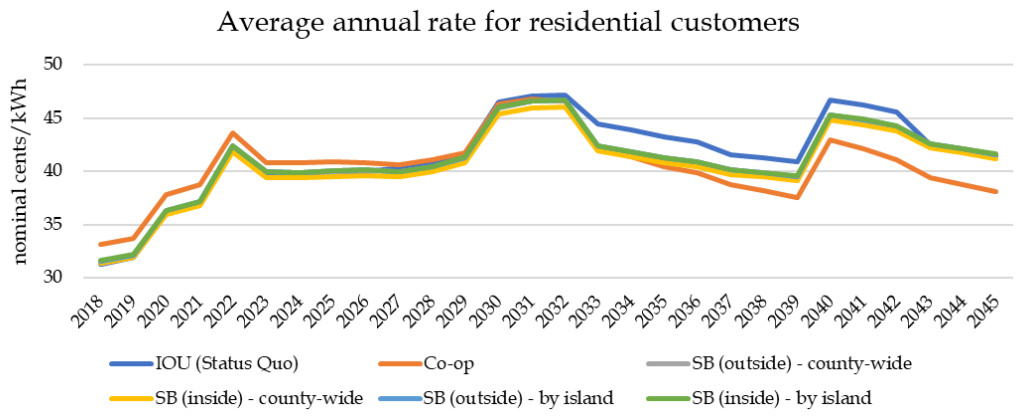
Similarly, Figure 30 illustrates the average impact, over the forecast horizon and considering the average consumption of each class of customer, that the various ownership models would have on monthly customer bills. These figures are shown in constant 2017 dollars.

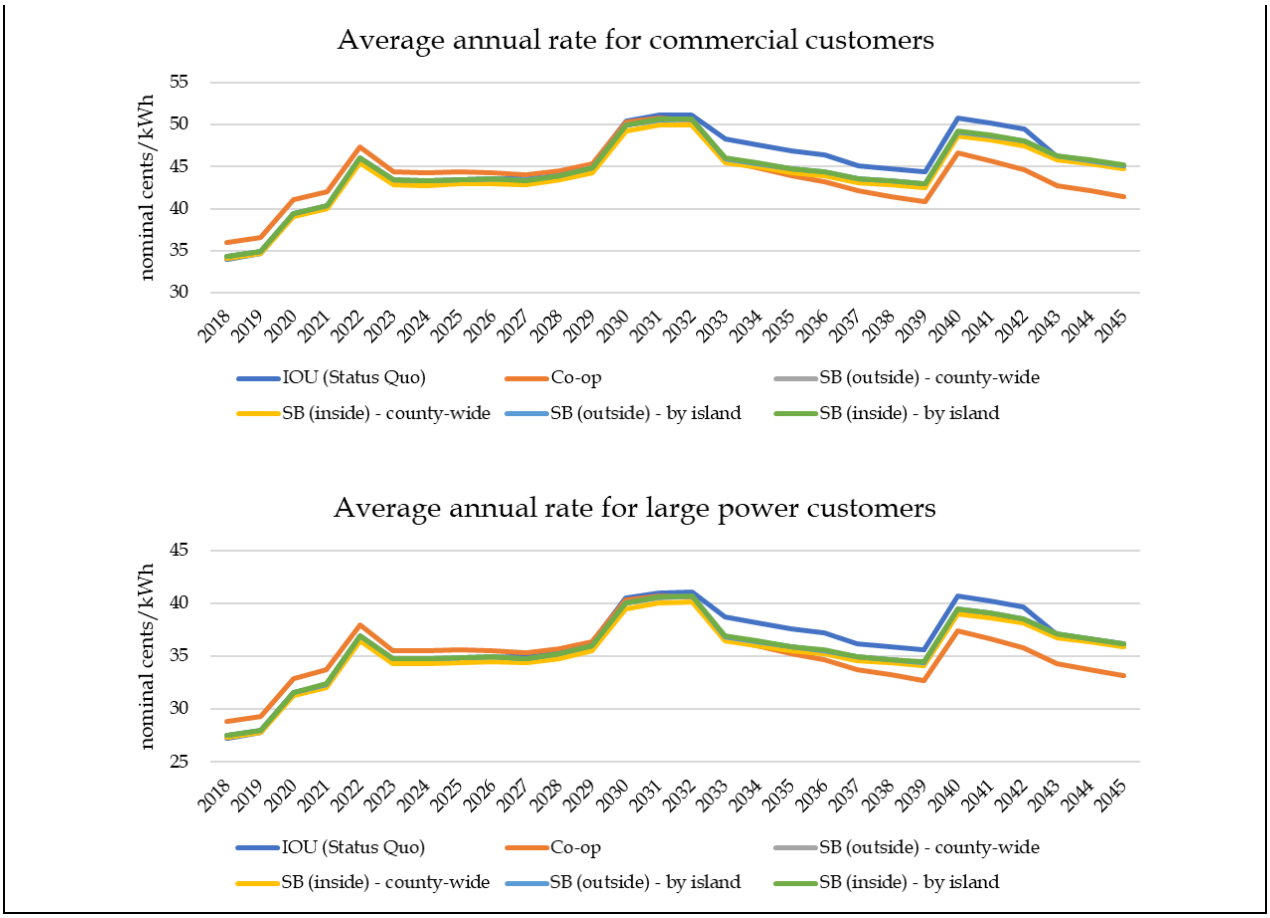
Figure 30. Projected average monthly bill over forecast horizon on the island of Maui for each ownership model

2017 dollars	IOU	Co-op	SB (outside)	SB (inside)
		MECO-wide transition		
Residential	$ 159	$ 156	$ 157	$ 155
Commercial	$ 1,017	$ 998	$ 1,003	$ 993
Large power	$ 59,564	$ 58,460	$ 58,753	$ 58,148
Other	$ 474	$ 465	$ 468	$ 463
		Island-specific transition		
Residential	$ 159	$ 156	$ 157	$ 157
Commercial	$ 1,017	$ 998	$ 1,004	$ 1,004
Large power	$ 59,564	$ 58,460	$ 58,790	$ 58,819
Other	$ 474	$ 465	$ 468	$ 468

The trends in projected average annual rates under various ownership models are similar for residential, commercial, and large power customers on the island of Maui in that they show a general increasing trend throughout the forecast horizon. The average year-on-year growth in forecasted average annual rates for all three customer types from 2018 through 2045 is 0.7% for the co-op model and 1.2% for all other ownership models. Figure 31 illustrates the trend in rates for different customer classes in Maui (values are in nominal cents per kWh).

Figure 31. Projected average annual rates forecast for the island of Maui under various ownership models





4.2.3.2 Lanai

The status quo IOU model is projected to have the lowest average rates Lanai. Over the forecast horizon, average rates for MECO residential customers on the island of Lanai are anticipated to be around 33.2 cents/kWh under the status quo and slightly higher at 33.5 cents/kWh and 32.8 cents/kWh under the SB models with county-wide transition and co-op model, respectively. Rates are expected to be significantly higher under the SB models if they are established separately on each island – 43.1 cents/kWh and 43.6 cents/kWh under the independent and ring-fenced SB models, respectively. The higher projected rates are driven by the high fixed costs of establishing an SB relative to the overall size of Lanai's system. Commercial and large power rates are similarly impacted, with the IOU model showing lower average rates, and the SB and co-op models resulting in higher average rates. These results are illustrated in Figure 32.

Note that in order to calculate these average rates over the forecast horizon, the Project Team converted the forecast rates from nominal dollars into constant 2017 dollars, before averaging all values over the forecast horizon.

Figure 32. Projected average rates over forecast horizon on the island of Lanai for each ownership model

2017 cents/kWh	IOU	Co-op	SB (outside)	SB (inside)
MECO-wide transition				
Residential	33.2	32.8	33.5	33.5
Commercial	34.9	34.4	35.2	35.2
Large power	28.1	27.7	28.3	28.3
Other	23.1	22.8	23.3	23.3
Island-specific transition				
Residential	33.2	32.8	43.1	43.6
Commercial	34.9	34.4	45.2	45.8
Large power	28.1	27.7	36.4	36.9
Other	23.1	22.8	30.0	30.4

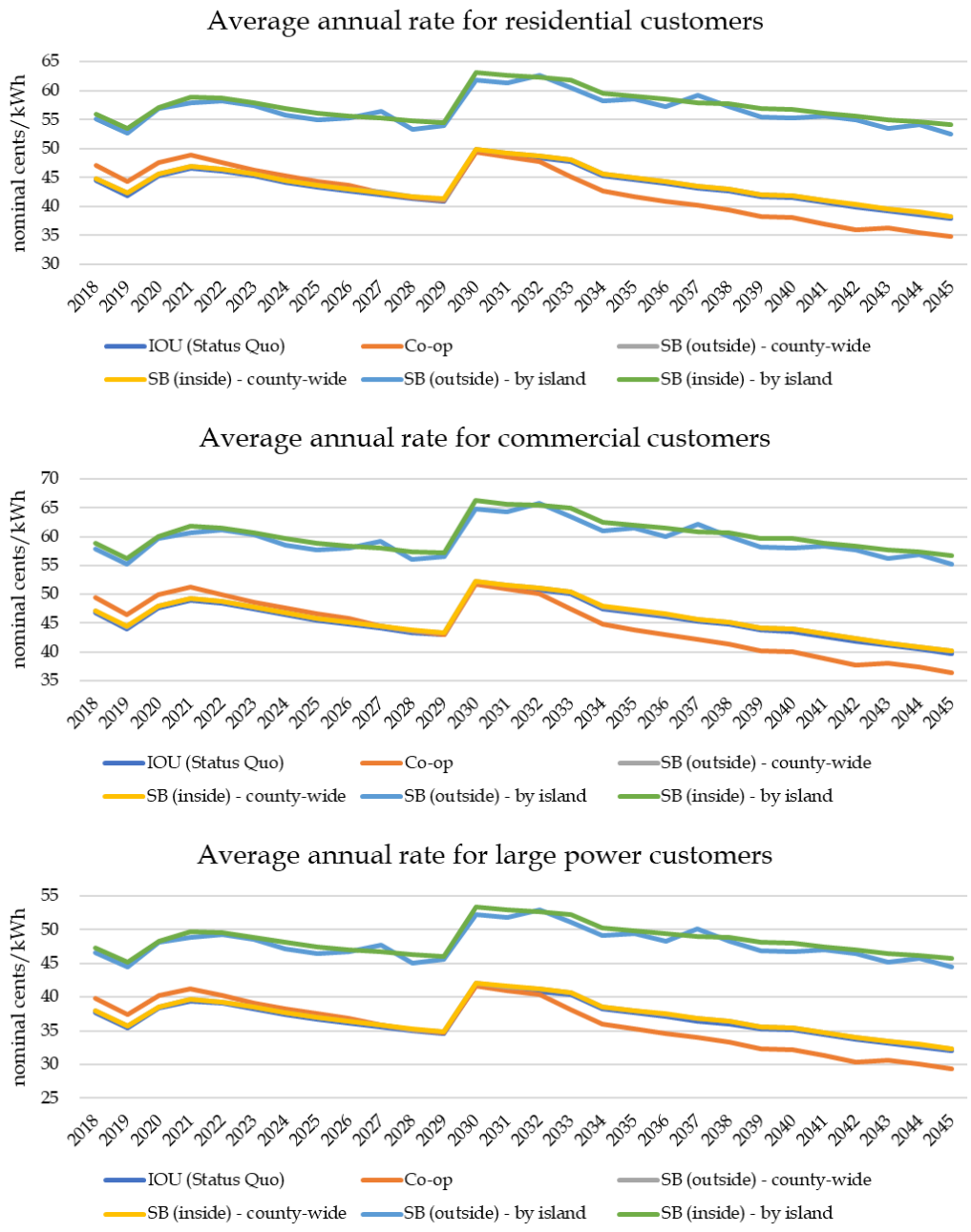
Similarly, Figure 33 illustrates the average impact, over the forecast horizon and considering the average consumption of each class of customer, that the various ownership models would have on monthly customer bills. These figures are shown in constant 2017 dollars.

Figure 33. Projected average monthly bill over forecast horizon on the island of Lanai for each ownership model

2017 dollars	IOU	Co-op	SB (outside)	SB (inside)
MECO-wide transition				
Residential	$ 129	$ 127	$ 130	$ 130
Commercial	$ 963	$ 949	$ 971	$ 971
Large power	$ 96,276	$ 94,906	$ 97,034	$ 97,080
Other	$ 546	$ 539	$ 551	$ 551
Island-specific transition				
Residential	$ 129	$ 127	$ 168	$ 170
Commercial	$ 963	$ 949	$ 1,248	$ 1,264
Large power	$ 96,276	$ 94,906	$ 124,801	$ 126,400
Other	$ 546	$ 539	$ 708	$ 717

The trends in projected average annual rates under various ownership models are similar for residential, commercial, and large power customers on the island of Lanai in that they demonstrate a general decreasing trend throughout the forecast horizon. The average year-on-year growth in forecasted average annual rates for all three customer types from 2018 to 2045 are approximately -1.0% under the co-op model, -0.5% under the IOU and county-wide SB models, and -0.1% under the island-specific SB models. Figure 34 illustrates the trend in rates for residential, commercial, and large power customers in Lanai (values are in nominal dollars).

Figure 34. Projected average annual rates forecast for the island of Lanai under various regulatory models



4.2.3.3 Molokai

In Molokai, ownership change is expected to raise the electricity rates on average for all customer classes reviewed, relative to the status quo. Over the forecast horizon, average rates for MECO residential customers on the island of Molokai are anticipated to be around 41.3 cents/kWh under

the IOU model, 40.8 cents/kWh for the co-op, and 41.8 cents/kWh for the county-wide SB models. For a separate SB established on Molokai, residential rates are forecasted to be significantly higher due to the small size of Molokai relative to the fixed costs of SB operations – 53.3 cents/kWh and 53.8 cents/kWh under the SB models (outside and inside, respectively). Commercial and large power rates are similarly impacted, with the status quo model showing lower average rates, and the SB and co-op models resulting in higher average rates. These results are illustrated in Figure 35.

Note that in order to calculate these average rates over the forecast horizon, the Project Team converted the forecast rates from nominal dollars into constant 2017 dollars, before averaging all values over the forecast horizon.

Figure 35. Projected average rates over forecast horizon on the island of Molokai for each ownership model

2017 cents/kWh	IOU	Co-op	SB (outside)	SB (inside)
		MECO-wide transition		
Residential	41.3	40.3	41.8	41.8
Commercial	45.2	44.1	45.7	45.8
Large power	42.7	41.6	43.2	43.2
Other	29.0	28.3	29.3	29.4
		Island-specific transition		
Residential	41.3	40.3	53.3	53.8
Commercial	45.2	44.1	58.4	58.9
Large power	42.7	41.6	55.1	55.6
Other	29.0	28.3	37.4	37.8

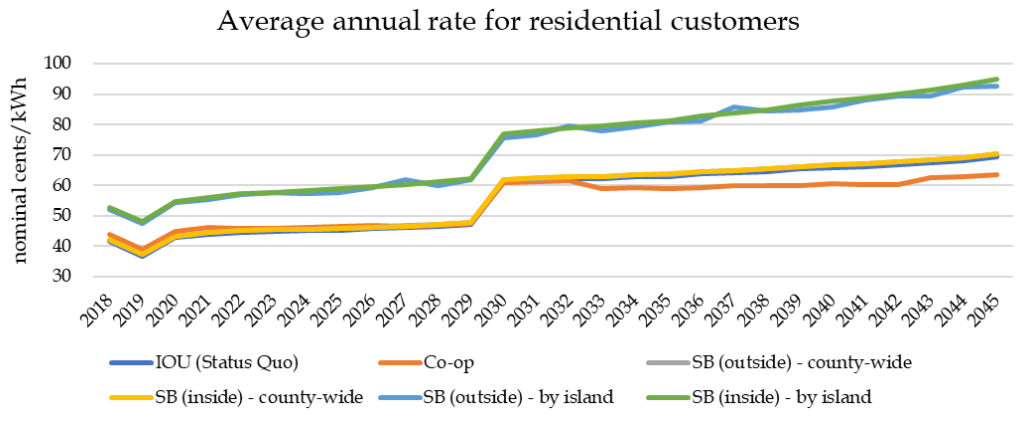
Similarly, Figure 36 illustrates the average impact, over the forecast horizon and considering the average consumption of each class of customer, that the various ownership models would have on monthly customer bills. These figures are shown in constant 2017 dollars.

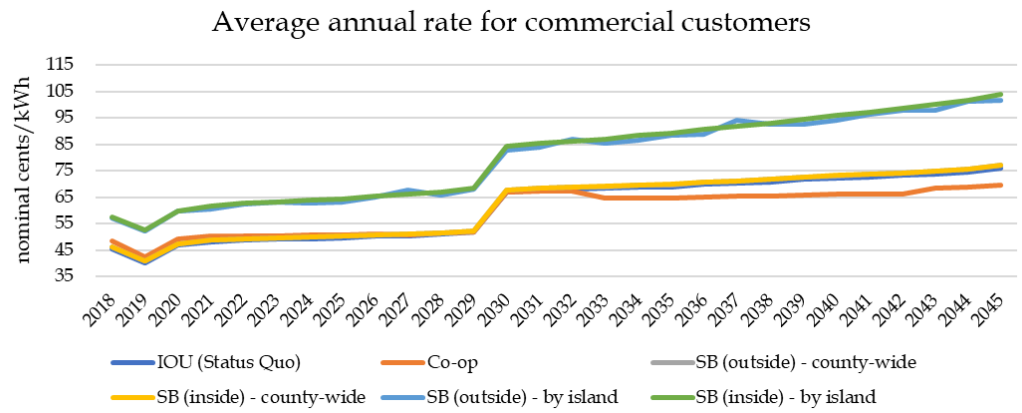
Figure 36. Projected average monthly bill over forecast horizon on the island of Molokai for each ownership model

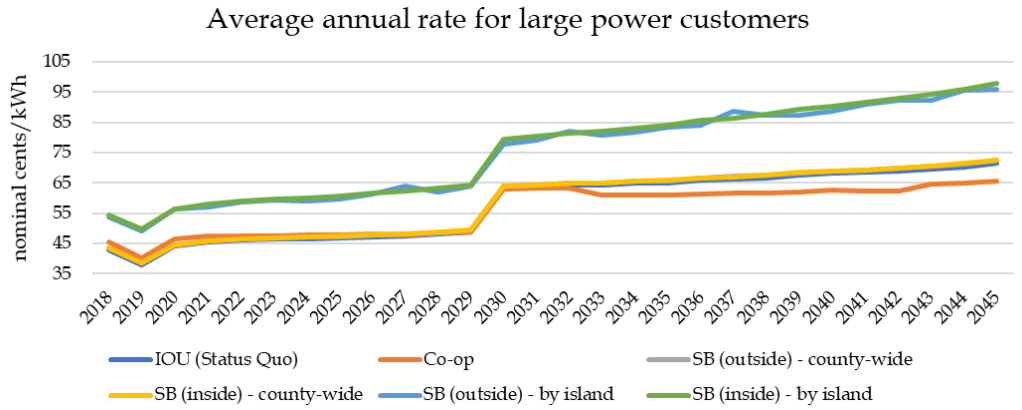
2017 dollars	IOU	Co-op	SB (outside)	SB (inside)
MECO-wide transition				
Residential	$ 94	$ 92	$ 95	$ 95
Commercial	$ 642	$ 630	$ 649	$ 649
Large power	$ 15,580	$ 15,302	$ 15,757	$ 15,765
Other	$ 1,084	$ 1,064	$ 1,096	$ 1,097
Island-specific transition				
Residential	$ 94	$ 92	$ 121	$ 122
Commercial	$ 642	$ 630	$ 827	$ 834
Large power	$ 15,580	$ 15,302	$ 20,066	$ 20,248
Other	$ 1,084	$ 1,064	$ 1,396	$ 1,409

The trends in projected average annual rates under various ownership models are similar for residential, commercial, and large power customers on the island of Molokai in that they demonstrate a general increasing trend throughout the forecast horizon. The average year-on-year growth in forecasted average annual rates for all three customer types from 2018 to 2045 are approximately 1.6% under a co-op model, 2.1% under the IOU and county-wide SB models, and 2.3% under the island-specific SB models. Figure 37 illustrates the trend in rates for residential, commercial, and large power customers in Molokai (values are in nominal dollars).

Figure 37. Projected average annual rates forecast for the island of Molokai under various regulatory models







4.2.4 KIUC

Over the forecast horizon, average rates for KIUC residential customers are anticipated to be the lowest under the co-op model, at approximately 38.1 cents/kWh, followed by the slightly higher average rates under the SB models at around 38.5 cents/kWh, and 40.7 cents/kWh under the IOU model. Commercial and large power rates are similarly impacted, with the co-op model resulting in lowest average rates, and the IOU model resulting in the highest average rates. These results are illustrated in Figure 38.

Note that in order to calculate these average rates over the forecast horizon, the Project Team converted the forecast rates from nominal dollars into constant 2017 dollars, before averaging all values over the forecast horizon.

Figure 38. Projected average rates over forecast horizon in Kauai County for each ownership model

2017 cents/kWh	IOU	Co-op	SB (outside)	SB (inside)
Residential	40.7	38.1	38.5	38.5
Commercial	40.2	37.7	38.0	38.0
Large power	35.8	33.5	33.9	33.9
Other	57.7	54.1	54.6	54.6

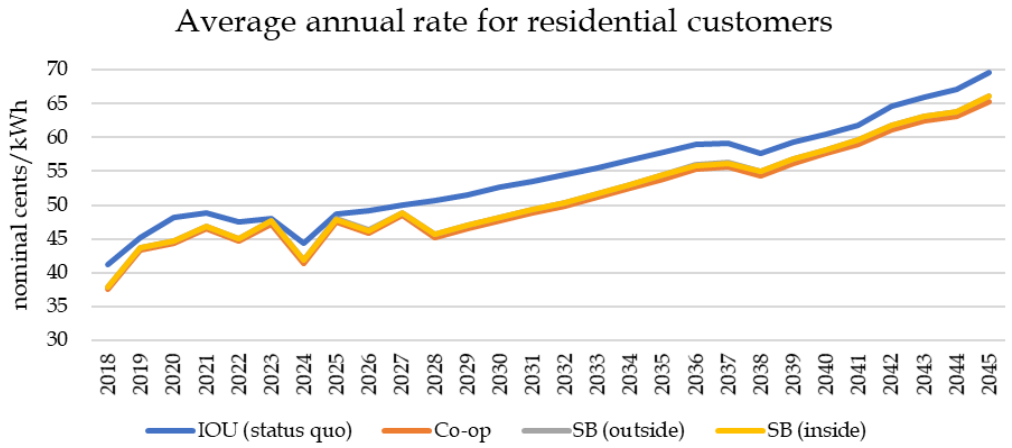
Similarly, Figure 39 illustrates the average impact, over the forecast horizon and considering the average consumption of each class of customer, that the various ownership models would have on monthly customer bills. These figures are shown in constant 2017 dollars.

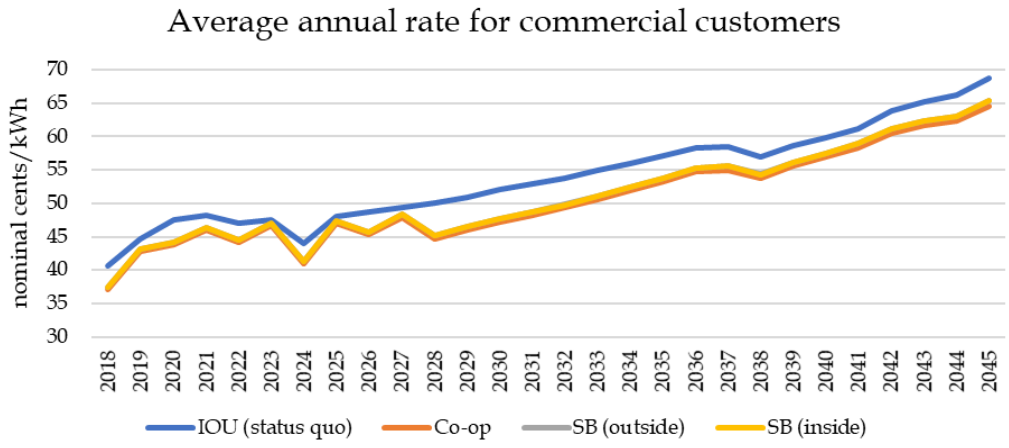
Figure 39. Projected qverage monthly bill over forecast horizon in Kauai County for each ownership model

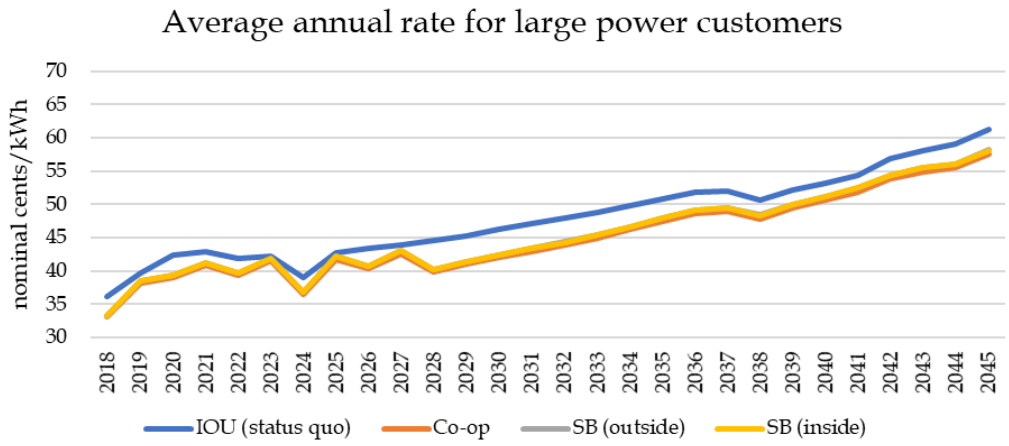
2017 dollars	IOU	Co-op	SB (outside)	SB (inside)
Residential	$ 167	$ 156	$ 158	$ 158
Commercial	$ 703	$ 659	$ 665	$ 665
Large power	$ 33,765	$ 31,644	$ 31,957	$ 31,950
Other	$ 30	$ 28	$ 28	$ 28

Overall, the trends in projected average annual rates under various ownership models are similar for residential, commercial, and large power customers in Kauai County in that they show a general increasing trend throughout the forecast horizon. The average year-on-year growth in forecasted average annual rates for all three customer types from 2018 through 2045 are 2.0% for the IOU model, and 2.2% each for the co-op, SB (outside), and SB (inside) models, respectively. Figure 40 illustrates the trend in rates for residential, commercial, and large power customers in Kauai County (values are in nominal dollars).

Figure 40. Projected average annual rates forecast for KIUC under various ownership models




Average annual rate for commercial customers
nominal cents/kWh
70
65
60
55
50
45
40
35
30
2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
IOU (status quo)
Co-op
SB (outside)
SB (inside)


Average annual rate for large power customers
nominal cents/kWh
70
65
60
55
50
45
40
35
30
2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
IOU (status quo)
Co-op
SB (outside)
SB (inside)

5 Appendix A: Scope of work to which this deliverable responds

Task 1.6.4 Matrix comparing system average retail rates under each ownership model through 2045 for an average residential, commercial, and industrial customer.

CONTRACTOR shall forecast system average retail rates through 2045 using the revenue requirement from 1.6.3. Provide a matrix comparison of forecasted retail rates under each ownership model.

DELIVERABLE FOR TASK 1.6.4. CONTRACTOR shall provide its conclusions and all work related to converting the revenue requirement each year into a fixed and variable rate component that is consistent with Hawaii's current rate structure. CONTRACTOR shall compare for each category of customer an assumed average consumption level, and how the average system rate or aggregate bill may change through 2045 for each ownership model. CONTRACTOR shall provide an MS Excel file with rates under each ownership model for an average residential, commercial, and industrial customer through 2045 and a PowerPoint summary, providing a comparison of these options. CONTRACTOR shall submit deliverable for TASK 1.6.4 to the STATE for approval.

6 Appendix B: List of works consulted

HECO. "Cost of Service Studies". *HECO 2017 Test Year: Direct Testimonies and Exhibits Book 10*. Page 7-8.

HECO Companies. *Rate & Regulations*. Website. <https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/hawaiian-electric-rates>. Access Date: March 8, 2018.

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KIUC. *Schedule "TOU-S"*. Website. <http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/tariffs/tariff1-tou-s.pdf>. Access Date: March 8, 2018.

Economic Evaluation of Ownership and Operation for Each Ownership Model

prepared for Hawaii Department of Business, Economic Development & Tourism ("DBEDT") by London Economics International LLC

April 3, 2018

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This document, Task 1.6.5, is one of several working papers issued as part of this engagement. It provides an overview of the options for financing capital expenditures associated with four ownership models: Investor-Owned Utility ("IOU"), an electric cooperative ("co-op"), an independent Single Buyer ("SB") outside of the utility, and a ring-fenced SB within the IOU.

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List of acronyms

CFC	Cooperative Finance Corporation
DBEDT	Hawaii Department of Business, Economic Development, and Tourism
DCF	Discounted Cash Flow
FFB	Federal Financing Bank
HECO	Hawaiian Electric Company
HEI	Hawaiian Electric Industries Inc.
HELCO	Hawaii Electric Light Company
IOU	Investor-Owned Utility
IPA	Illinois Power Agency
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company
NCSC	National Cooperative Services Corporation
O&M	Operations and Maintenance
OPA	Ontario Power Authority
PUC	Hawaii Public Utilities Commission
REDG	Rural Economic Development Grant
ROE	Return on Equity
RUS	Rural Utilities Service
SB	Single Buyer
TIER	Times Interest Earned Ratio
TNB	Tenaga Nasional Berhad
USDA	United States Department of Agriculture
WACC	Weighted Average Cost of Capital

1 Executive Summary

London Economics International LLC, together with Meister Consultants Group (the "Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which corresponds to Task 1.6.5 in the project scope of work, provides an evaluation of the options for financing capital expenditures associated with four ownership models: Investor-Owned Utility ("IOU"), an electric cooperative ("co-op"), an independent Single Buyer ("SB") outside of the utility, and a ring-fenced SB within the IOU.

1.1 IOU

IOUs usually finance capital expenditures through a combination of debt (short- and long-term) and equity (e.g., stock). Debt financing is when a firm obtains capital through the sale of debt instruments to investors, may they be individuals and/or institutions. Said individuals and/or institutions, in return, are promised the rebalance of debt plus interest. Conversely, equity financing is when a firm obtains capital through the sale of shares, or essentially ownership interest. The sum of the cost of equity and debt financing represent a company's cost of capital, and the cost of capital represents the minimum returns a firm must make to satisfy all providers of capital.

1.2 Co-ops

Similar to an IOU, a co-op can finance capital expenditures through debt or equity. However, the sources and costs of acquiring capital are different for a co-op than for an IOU. The co-op entity's members may contribute equity to the purchase of assets, for instance. A co-op's margins in any year can be referred to as patronage capital, and each member's patronage capital account represents his/her portion of ownership in the co-op. Depending on the co-op's financial status, the co-op may return a proportion of the patronage capital to members as checks or bill credits, thereby considered as retired patronage capital. The remaining amount remains credited to members' accounts but is invested on the grid, representing the equity capital provided by co-op members. Conversely, the co-op utility may choose to leverage debt as rural electric co-ops have access to low-interest loans to fund acquisitions of other utilities through both public and private sources.

1.3 Single Buyer

As introduced in the deliverable for Task 1.1.1, there are many variations of the Single Buyer ("SB") approach. It can be set up as a stand-alone, not-for-profit entity, or as part of an independent system operator ("ISO"). Alternatively, the utility itself can also take on the role.

With appropriate safeguards to assure that it is operating in a fair and transparent manner, the SB entity can be embedded within the utility. This approach entails setting up a new legal entity to serve as the SB within the utility, which would be appropriately ring-fenced from other utility

operations. The ring-fencing mechanism would allow the SB to take on the responsibility for the management of reliability planning and electricity procurement services.

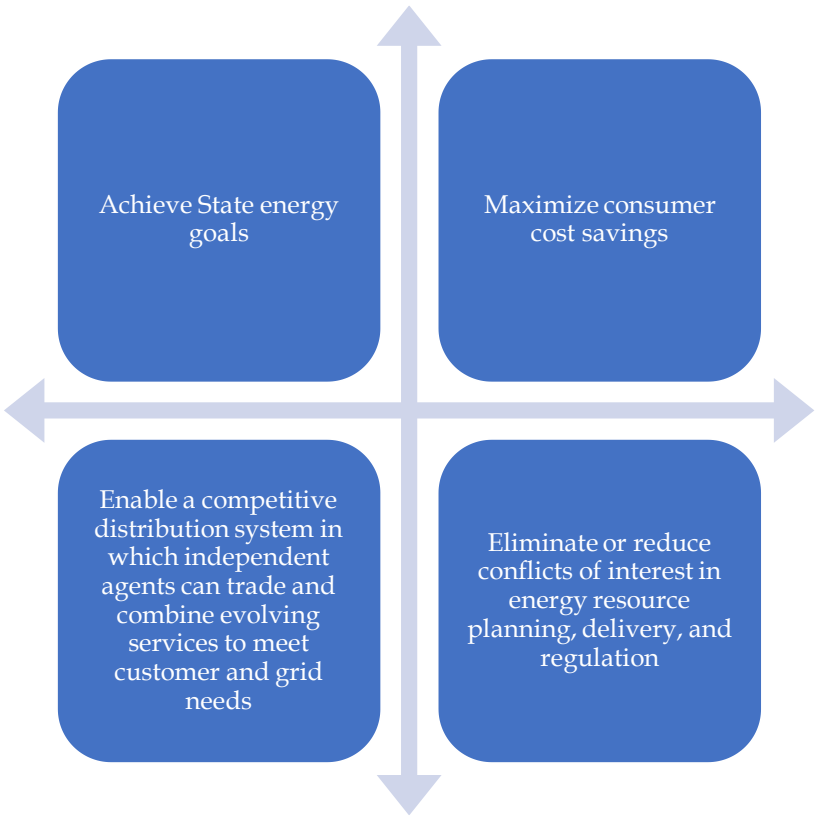
To finance the day-to-day operations, the SB revenue requirement would be combined with that of the utility and consequently recovered through electricity rates. The SB would thus be able to recover its costs related to power procurement and to its operations.

In the case of an SB outside of the utility, it is required to set up a separate entity which is not associated with the utility. The SB's revenue requirement would be recovered from fees assessed on consumers' electricity bills to be able to finance its day-to-day operations. These fees would need to be approved by the Public Utility Commission. Alternatively, if set up as a government agency, the SB operations can be financed through funds appropriated by the legislature.

2 Introduction and scope

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. LEI, through a competitive sealed proposals procurement,[1] was contracted to perform this study.[2]

Figure 1. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[3] listed in Figure 1. The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory

[1] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[2] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[3] House Bill No. 1700 Relating to the State Budget.

models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[4]

This deliverable corresponds to Task 1.6.5 in the project scope of work. It identifies potential financing mechanisms for each ownership model studied, which are Investor-Owned Utility ("IOU"), co-op, and Single Buyer ("SB" - both inside or outside the utility). This document also includes a discussion of the cost and availability of each identified financing mechanism

[4] Hawaii Contract No. 65595. Scope of Services.

3 Major cost components of electric utilities

As introduced in the Task 1.4.2 report, major cost components for an electric utility are comprised of capital costs and operating and maintenance ("O&M") costs. Since utilities need to raise capital in order to pay for capital expenditures, these costs can be further subdivided into the utility's expenditure on purchasing or replacing assets, and the cost of financing this spending.

Capital expenditures can take many forms. For instance, the acquisition by a utility or parent company of assets from another entity needs to be financed. The purchase price would depend on a mutually agreed-upon valuation of the assets and transaction costs. Additionally, the purchase price and terms would need to be approved by the PUC. Financing the acquisition is typically dependent on financing mechanisms available to the acquiring party (such as IOU, co-op, etc.), and independent of the ownership structure of the former asset owners.

Capital expenditures can also accrue without a change in ownership of utility assets, for instance through investments in:

- new electric plant infrastructure (production, transmission, or distribution);
- fuel, materials, or supplies inventory;
- various regulatory assets; or
- any other type of investment that is amortized over multiple years.

On the other hand, O&M costs are expenses for day-to-day operations of the utility and are comprised of costs associated for instance to:

- the operations and maintenance of assets;
- employee compensation and benefits;
- fuel and purchased power;
- administrative expenses; or
- taxes.

O&M expenditures are not financed. These costs are passed directly on to consumers so that they are paid for on an annual basis from revenues from power sales. In a rate case, the PUC typically determines and authorizes parameters such as the total yearly revenues required by the utility to cover expenses and obtain a fair return on equity, such that the revenue requirement forms the basis to determine rates. This is discussed in detail in Task 1.6.1 working paper.

Rate cases typically include allowances for working capital, in addition to the valuation, to ensure sufficient liquidity for the financing of day-to-day operations. Working capital refers to the difference between current assets and current reliabilities; the value represents the capital that is required for short-term items (e.g., cash, inventories) needed on a day-to-day basis. The calculation is based on the average lag between accounts payable, or expenditures (e.g., employee compensation, fuel costs, maintenance, etc.), and accounts receivable, or the amount of sales billed to customers (i.e., payments that have yet to be made).

4 Investor-Owned Utilities

IOUs are electricity providers that can be publicly traded or privately held. Since an IOU's management reports to a board of directors that carry a fiduciary duty to its shareholders, the mission of an IOU is to optimize the return on investment for said shareholders. For instance, the parent company of HECO, HELCO, and MECO ("the HECO Companies"), Hawaiian Electric Industries, Inc. ("HEI"), is an IOU that is traded on the New York Stock Exchange ("NYSE"), with 50% of its shares held by institutions.[5]

Examples of IOU ownership structures include:

- publicly traded IOU or utility holding company;
- private equity or other private investor group;
- acquisition by a private entity and operating as a Benefit Corporation ("B-Corporation").[6]

4.1 Financing options

IOUs usually finance capital expenditures through a combination of debt (short- and long-term) and equity (e.g., stock), subject to PUC approval. Simply put, debt financing is when a firm obtains capital through the sale of debt instruments to investors, may they be individuals and/or institutions. Said individuals and/or institutions, in return, are promised the rebalance of debt plus interest. Conversely, equity financing is when a firm obtains capital through the sale of shares, or essentially ownership interest. The sum of the cost of equity and debt financing represent a company's cost of capital, and the cost of capital represents the minimum returns a firm must make to satisfy all providers of capital.

With debt, because the lender does not have a claim to equity in the business, debt does not dilute the owner's ownership interest in the company. The lender is entitled only to repayment of the agreed-upon principal of the loan plus interest and has no direct claim on future profits of the business. It does, however, provide certainty of payment to the lender (absent any default). Returns on equity, however, are not guaranteed and can only occur after debt repayment obligations are met. As such it is riskier, and therefore carries an expectation of a higher return. However, the larger a company's debt-equity ratio, the riskier the company is considered by lenders and investors. Accordingly, a business is limited as to the amount of debt it can carry.

4.2 Debt financing

The cost of debt is driven by several factors, such as market conditions, the term of the loan, and the IOU's cost of credit. The cost of credit is based on determinations by credit rating agencies such as Moody's, Standard & Poor's ("S&P"), or Fitch Group. These rating agencies are private-sector companies that issue credit ratings for large-scale borrowers (e.g., companies or

[5] Hawaiian Electric Industries, Inc. *Institutional Ownership*. Website.
<http://www.nasdaq.com/symbol/he/institutional-holdings>.

[6] It is also possible that HEI could choose to attain B-Corporation certification without an external acquisition.

governments) as a means of scoring the borrower's ability to repay its loans.[7] As a consequence, these scorecards can affect how much borrowers are charged for debts they issue. The credit scores, ranging from AAA (the best credit rating) to D (the worst in S&P and Fitch ratings, with C as the worst in Moody's ratings), are assessed based a variety of parameters. S&P, for instance, for their Corporate Rating Analysis, uses a combination of business risk and financial risk parameters that are ultimately used to arrive at a Corporate Credit Rating.[8] Business risk factors include country risk, industry characteristics, company position, or profitability/peer group comparisons. Financial risk factors include accounting, governance/risk tolerance/ financial policy score, cash flow adequacy, capital structure/asset protection score, and liquidity/short-term factors score.[9] As an example, Figure 2 provides an overview of various comparable utilities (generally based on generation capacity and sales) credit ratings, including that of the HECO Companies' parent HEI.

Figure 2 HECO Companies' parent and comparable utilities average cost of debt, 2015-2018

Utility name	Generation capacity (MW)	Location	Moody's Credit Rating	Average cost of debt
ALLETE, Inc.	1,932	WI, MN	A3	3.9%
Alliant Energy Corp. (Wisconsin Power and Light)	2,481	WI	A2	5.2%
Avista Corp.	1,862	MT, ID, WA	Baa1	5.7%
El Paso Electric Co.	2,080	NM, TX	Baa1	6.3%
Great Plains Energy, Inc. (Greater Missouri Operations Co.)	2,074	MO	Baa1	4.2%
Northwestern Corp.	1,249	WY, SD, MT	A3	3.5%
PNM Resources (Public Service Co. of NM)	2,481	NM	Baa3	5.0%
Westar Energy Inc.	2,481	KS	Baa1	5.0%
Wisconsin Energy Corp. (Wisconsin Public Service)	2,481	WI	A3	6.3%
Hawaiian Electric Industries	**1,669**	**HI**	**Baa2**	**5.2%**

Source: Credit Rating from Moody's (Accessed 2018). Generation capacity from 10-K forms or annual reports for all utilities and does not include IPP generation capacity. Average cost of debt from SNL (Accessed March 2018) and LEI Analysis.

As illustrated in Figure 2, the cost of debt for comparable utilities range from 3.5% to 6.3%. It is important to mention that in addition to the credit rating, the average cost of debt depends on several other factors such as market conditions when the debt was contracted, as well as the term of the loan.

In 2014, HECO entered into a revolving non-collateralized credit agreement with a syndicate of nine financial institutions to create the Hawaiian Electric Facility, increasing its line of credit to

[7] BBC. *What is a rating agency?* October 20, 2014. Web. March 15, 2018. <http://www.bbc.com/news/10108284>

[8] Katz, L.F., Latin America Ratings, Standard & Poor's. *Rating Agencies and Their Methodologies.* Seminar, Senior Bank Supervisors from Emerging Economies, World Bank/IMF/Federal Reserve System. Washington D.C. October 21, 2008.

[9] Ibid.

$200 million from $175 million.[10] The facility was created to support the issuance of or repay short-term debt, make loans, as well as for capital expenditures, working capital, and general corporate purposes. All HECO Companies can draw from the facility so long as the debt-to-capital ratio does not exceed 65% for HECO or 42% each for MECO and HELCO.[11]

4.3 Equity financing

Because equity is raised via the sale of common or preferred stock shares, the cost of equity is determined by the conditions of the market and the perceived risk associated with the firm. Put differently, it is determined by the average expected return on investment, which in turn is influenced by the market risk. The market risk serves as an indicator of potential losses for the investor; sources can vary but include changes in interest rates, recessions, natural disasters, and political instability. The cost of equity can be determined using the Capital Asset Pricing Model ("CAPM"), a formula that uses the total average market return and a beta[12] value of a stock to identify the expected rate of return. The market return can be estimated by a market index such as the Dow Jones Industrial Average of the S&P 500.

A company has added value if its return on equity ("ROE") is greater than the cost of equity. In terms of the risk of regulated versus unregulated utilities, regulated utilities typically present lower ROEs due to their higher certainty of revenues (lower risk) when compared to owners of merchant assets.

In this regard, it is also crucial to highlight the difference between a public company and a private company. A public company is one that has issued an Initial Public Offering ("IPO") and is henceforth publicly traded in one or more stock exchanges. Conversely, a private company is one that is owned privately and thus does not have its shares traded on public exchanges or have shares issued through an IPO. In this regard, the HECO Companies' parent HEI is publicly traded, and thus, equity is obtained from stock.

As illustrated in Figure 3, the average ROE for comparable utilities ranges from 9.3% to 10.0%, which is higher than the average cost of debt. HEI has the lowest debt-to-equity ratio of the list at approximately 71%, which contributes to it having the highest average WACC at 8.3%.

In a rate case, the PUC typically determines and authorizes parameters such as the total annual revenues required by the utility to cover expenses and obtain a fair return on equity, such that

[10] Hawaiian Electric Industries, Inc. *Form 10-K: Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.* 2016.
<http://www.hei.com/Cache/1500096268.PDF?O=PDF&T=&Y=&D=&FID=1500096268&iid=1031123>

[11] Ibid.

[12] Beta is a measure of the volatility, or systematic risk, of a security (or portfolio) in comparison to the market as a whole.

the revenue requirement forms the basis to determine rates.[13] These decisions are typically made based on estimates submitted by the utility, and upon assessing the utility's and intervener's views of the company's capital structure.[14]

Figure 3 HECO Companies' and comparable utilities' capital structures, 2015-2018

Utility name	Debt-to-equity ratio	Average cost of debt	Average ROE	Average WACC
ALLETE, Inc.	85.8%	3.9%	9.3%	7.1%
Alliant Energy Corp. (Wisconsin Power and Light)	91.6%	5.2%	10.0%	7.9%
Avista Corp.	100.0%	5.7%	9.5%	7.6%
El Paso Electric Co.	106.8%	6.3%	9.7%	7.7%
Great Plains Energy, Inc. (Greater Missouri Operations Co.)	82.4%	4.2%	9.9%	7.7%
Northwestern Corp.	86.5%	3.5%	10.0%	7.2%
PNM Resources (Public Service Co. of NM)	101.6%	5.0%	9.6%	7.2%
Westar Energy Inc.	88.3%	5.0%	10.0%	8.0%
Wisconsin Energy Corp. (Wisconsin Public Service)	98.1%	6.3%	10.0%	8.2%
Hawaiian Electric Industries	**71.9%**	**5.2%**	**9.5%**	**8.3%**

Source: SNL (Accessed March 2018); Hawaiian Electric Industries Annual Report (2017); LEI analysis

Note: ROEs of Great Plains Energy Inc., Northwestern Corporation, and Westar Energy Inc. are present case ROEs requested by the company; all three utilities' rate cases involved settlements and as such, ROEs authorized by the commission are unavailable.

The HECO Companies source approximately 42% and 57% of their capital from long-term debt and common stock, respectively.[15] HECO serves as the guarantor for its subsidiaries' special purpose revenue bonds, their respective notes issued, and trust preferred securities.[16] HECO would presumably withdraw this guarantee if MECO or HELCO changed ownership, which could impact their borrowing costs.

[13] Hawaiian Electric Company. *Key Performance Metrics: Financial*. Web. March 10, 2018. <https://www.hawaiianelectric.com/about-us/key-performance-metrics/financial>

[14] Ibid.

[15] Details regarding the HECO Companies' capital structure (i.e. the proportion of debt and equity) as of December 31, 2016 can be found in Task 1.4.2, Figure 2.

[16] HECO. *Annual Report of the Hawaiian Electric Company to the Public Utilities Commission, State of Hawaii, for the year ending December 31, 2016.* May 2017, page 109.1.

5 Cooperative

Under a cooperative ("co-op") ownership model, the utility would effectively be owned by its members, who are typically its customers, and is incorporated under the laws of the state under which it operates. Unlike IOUs, co-op utilities lack a profit motive and allow greater customer control over the utility. When a co-op has net earnings, they are returned to its members based on each member's capital contribution, or patronage. Furthermore, rural electric co-ops are considered non-profit corporations and hence exempt from federal taxes under IRS 501(c)(12), if at least 85% of their annual income comes from members. A co-op can be defined by three important organizational and operational principles:[17]

1. **Democratic control** – It must periodically hold democratically conducted meetings and elections for officers, on a one member, one vote basis;

2. **Operation at cost** – All excess operating revenues are allocated among members; and

3. **Subordination of capital** – It should ensure that shareholders or equity investors who control capital are not the ones also controlling capital or receiving most of the pecuniary benefits.

The Kauai Island Utility Cooperative ("KIUC"), providing electric service on the island of Kauai, is an example of a co-op operating in Hawaii; it became Hawaii's first and only electric co-op when it purchased the utility from Citizens Communications Company ("Citizens"). As detailed in Task 1.4.2, the major cost components of a co-op are comprised of non-recurring and recurring costs. Non-recurring costs include setup, legal, and regulatory costs, acquisition costs, and personnel and organizational transition costs, whereas recurring costs include the cost of capital, taxes, and regulatory costs. Considering the cost components of a co-op and under the assumption that the acquiring entity is also a co-op, LEI discusses the available means to finance capital expenditures of a co-op utility in the following sections.

5.1 Financing options

Similar to an IOU, a co-op can finance capital expenditures through debt or equity. However, the sources and costs of acquiring capital are different for a co-op than for an IOU. The co-op entity's members may contribute equity to the purchase of assets, for instance. As mentioned earlier, a co-op's margins in any year can be referred to as patronage capital. Each member's patronage capital account represents his/her portion of ownership in the co-op. Each year, margins are allocated as credits based on the members' electricity usage in that year. Depending on the co-op's financial status, the co-op may return a proportion of the patronage capital to members as checks or bill credits, thereby considered as retired patronage capital. The remaining amount remains credited to members' accounts but is invested on the grid, representing the equity capital provided by co-op members.

[17] Co-op Law. *Rural Electric Cooperatives (REC)*. Web. March 10, 2018. < http://www.co-oplaw.org/co-op-basics/types/energy-cooperatives/>

Conversely, the co-op utility may choose to leverage debt – a likely pathway for cooperatives given their access to low-cost debt.

5.2 Debt financing

With regards to debt, rural electric co-ops can often utilize low-interest loans to fund acquisitions of other utilities through both public and private sources. Public sources include the United States Department of Agriculture's ("USDA") Rural Utilities Service ("RUS"), while private sector sources include the National Rural Utilities Cooperative Finance Corporation ("CFC") and the National Cooperative Services Corporation ("NCSC"). RUS loans currently account for less than 40% of total co-op financing in the US, whereas over 60% of financing is generated from private sector sources such as CFC and NCSC; nonetheless, RUS loans serve as a vital source of funding for co-ops.[18]

The RUS Electric Program provides loans that aid in financing the maintenance, expansion, and upgrades of electric infrastructure (i.e., distribution, transmission, and generation facilities) in rural areas, as well as funding for demand-side management, energy efficiency, and conservation schemes, and on- and off-grid renewable systems.[19] The RUS Electric Program has approximately 700 borrowers in 46 states, with a loan portfolio of about $46 billion.[20] The RUS Electric Program's functional structure is comprised of three offices: the Office of Loan Origination and Approval ("OLOA"), the Office of Portfolio Management and Risk Assessment (OPMRA"), and the Office of Policy, Outreach, and Standards ("OPOS"). Loan products include the following:[21, 22]

1. **Hardship Loans** – These loans may be used by rural applicants in economically distressing situations, or those recovering from an unavoidable event (e.g., natural disasters), and are offered at a 5% interest rate for up to 35 years;

2. **Municipal Rate Loans** – Interest rates are based on the rates available in the municipal bond market, but borrowers are required to seek supplemental financing for 30% of their capital requirements;

3. **Treasury Rate Loans** – Interest rates at the prevailing market rates for US Treasuries; and

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[18] *Co-op Law. Rural Electric Cooperatives ("RECS").* Web. March 5, 2018. <http://www.co-oplaw.org/co-op-basics/types/energy-cooperatives/#Government_Programs_and_Financial_Support>

[19] USDA. *Electric Programs*. Web. March 5, 2018. <https://www.rd.usda.gov/programs-services/all-programs/electric-programs>

[20] Ibid.

[21] USDA. *Electric Infrastructure Loan & Loan Guarantee Program.* Web. March 5, 2018. <https://www.rd.usda.gov/programs-services/electric-infrastructure-loan-loan-guarantee-program>

[22] USDA. *Rural Utilities Loan Interest Rates.* Web. March 5, 2018. <https://www.rd.usda.gov/programs-services/services/rural-utilities-loan-interest-rates>

4. **Guaranteed Loans –** The Federal Financing Bank ("FFB"), an instrument of the Treasury Department, provides the loans, which are guaranteed by RUS. The interest rates on guaranteed loans are based on the market rate for a US Treasury of the same maturity, plus 0.125%.

The Rural Economic Development Loan & Grant ("REDLG") program is also one other government lending scheme that provides zero-interest loans and grants through electric cooperatives, with local businesses as the ultimate recipients of said loans and grants.[23] The REDLG program is applicable to rural areas and towns with populations of 50,000 or less. The applying entity must be a former RUS borrower who has borrowed, repaid, or pre-paid a loan; a nonprofit utility that is eligible to receive aid from the Rural Development Electric or Telecommunications program; or a current Rural Development Electric or Telecommunication Program borrower.[24] Electric co-ops may receive grants of up to $300,000 from the USDA to establish revolving loan funds ("RLF") for the provision of loans for local businesses that generate or retain rural employment.[25] The on-lending entity receives said funds for 10 years at a 0% interest rate and is required to match 20% of grant funding.[26] Local businesses repay the co-op, and upon termination of the RLF, the co-op repays USDA.[27]

The RUS also offers High Energy Cost Grants that aid retail or power supply providers in eligible rural areas. These include state and local government entities, federally recognized Tribes and Tribal entities, non-profits, and for-profit businesses. As per the USDA, eligible areas are areas in the United States, U.S. Territories, or areas legally eligible for the USDA RUS Programs that have an annual average household energy cost 275% greater than the national average under the benchmarks in the Notice of Solicitation of Applications ("NOSA").[28,29] Said grants can be used by electric co-ops for the acquisition, construction, or improvement of generation, transmission, and distribution facilities; renewable energy facilities (e.g., solar, wind, hydropower, and biomass technologies) for on- or off-grid electric power generation, for instance; and backup or emergency

[23] USDA. "Rural Economic Development Loan & Grant Program." Web. March 5, 2018. <https://www.rd.usda.gov/programs-services/rural-economic-development-loan-grant-program>

[24] Ibid.

[25] Ibid.

[26] Ibid.

[27] Ibid.

[28] "High Energy Cost Grants." *USDA*. Web. March 5, 2018. <https://www.rd.usda.gov/programs-services/high-energy-cost-grants>

[29] NOSA can be accessed at: "Announcement of Grant Application Deadlines and Funding Levels for the Assistance to High Energy Cost Rural Communities Grant Program." *Federal Register*. October 12, 2017. Web. March 16, 2018. <https://www.federalregister.gov/documents/2017/10/12/2017-22042/announcement-of-grant-application-deadlines-and-funding-levels-for-the-assistance-to-high-energy>

power generation or energy storage.[30] The grants can also be used for the implementation of initiatives pertaining to energy efficiency improvements, as well as programs for improving the quality and cost of energy service, to name a few.[31]

The CFC, on the other hand, is a non-profit finance cooperative that supports electric co-ops in their goal of delivering power in a safe, affordable, and reliable manner to approximately 42 million customers.[32, 33] With goals and objectives similar to those of CFC, NCSC provides financial support for for-profit subsidiaries of electric co-ops, business solutions to increase efficiencies of co-ops, transitional and permanent financing for acquisitions, and financing for cooperative partners.[34] Both short- and long-term loans are provided at fixed and variable interest rates for periods ranging from one month to 30 years.[35]

In the case of KIUC, on November 1st, 2002, it became the first electric co-op in Hawaii when it purchased the electric utility Kaua'i Electric ("KE") from Citizens. In order to finance the acquisition cost of approximately $218 million (including transaction costs), KIUC obtained lines of credit from the CFC, as well as the federal government.[36] In 2016, KIUC had a debt-to-equity ratio of approximately 1.6 in 2016, with the cost of debt varying from 1% to 5%, and a weighted average interest rate (cost of debt) of approximately 4.1%.[37,38]

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[30] USDA. "High Energy Cost Grants." *USDA*. Web. March 5, 2018. <https://www.rd.usda.gov/programs-services/high-energy-cost-grants>

[31] Ibid.

[32] "Overview." *National Rural Utilities Cooperative Finance Corporation.* Web. March 5, 2018. <https://www.nrucfc.coop/content/cfc/about_cfc/overview.html>

[33] "Our Member-Owners." *National Rural Utilities Cooperative Finance Corporation.* Web. March 5, 2018. <https://www.nrucfc.coop/content/cfc/about_cfc/our-members.html>

[34] "Overview." *National Rural Utilities Cooperative Finance Corporation.* Web. March 5, 2018. <https://www.nrucfc.coop/content/cfc/about_cfc/overview.html>

[35] Ibid.

[36] KIUC. *Consolidated Financial Statements December 31, 2015 and 2014.* <http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/financials/2015%20Audited%20Financial%20Statements.pdf>

37 KIUC. Consolidated Financial Statements, December 31, 2016 and 2015. Note 8-Long-term Debt, Page 17. <http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/financials/2016%20Audited%20Financial%20Statements.pdf>

[38] KIUC. *Kauai Island Utility Cooperative 2016 Annual Report.*

5.3 Equity financing

Cooperatives have different sources for equity financing than IOUs. In addition to the equity contributions of its founding members, all electricity users can choose to become a member of the co-op and make capital contributions through rates.

Co-ops use the revenue collected through rates to pay for operating expenses and debt service (interest and principal). The remainder, or net income, represents the co-op's margin for the year, which can be turned into patronage capital. Each member has a patronage capital account, representing his/her ownership of the co-op. Every year, the margins are allocated to the members as credits to their patronage capital account. The distribution is based on the members' electricity usage in that year. Depending on the state of the co-op's finances, it may return a certain proportion of patronage capital to members every year as checks or bill credits. The patronage capital that is returned to the members is considered retired. Generally, co-ops retire patronage capital by older vintages first.

The remaining patronage capital remains credited to the members' account but is invested by the co-op in the grid. This is the equity capital provided by a co-op's owners – its members. Thus, co-ops can grow their equity (patronage capital) if new patronage capital is greater than the amount retired. In the case of KIUC, the amount of patronage capital that it returns to its members is generally limited to 25% margins in the prior calendar year. This has enabled KIUC to grow its equity while lowering its indebtedness.

Contrary to IOUs, equity financing for co-ops does not have a set or target "cost." The co-op revenue requirement is not based on a target ROE value for equity, but rather is based on the Times Interest Earned Ratio ("TIER") as discussed in Task 1.4.2. TIER is a solvency ratio that measures a co-op's ability to meet its long-term debt obligation. As such, the co-op's weighted average cost of capital ("WACC") can only be implicitly derived from the PUC-approved TIER value and revenue requirement.

6 Single Buyer

As introduced in the deliverable for Task 1.1.1, there are many variations of the Single Buyer ("SB") approach. It can be set up as a stand-alone, not-for-profit entity, or as part of an independent system operator ("ISO"). Alternatively, the utility itself can also take on the role. In this section, LEI discusses the SB financing options in the cases where the entity is within the utility, as well as in the case of an external SB.

6.1 Single buyer (inside)

With appropriate safeguards to assure that it is operating in a fair and transparent manner, the SB entity can be embedded within the utility. This approach entails setting up a new legal entity to serve as the SB within the utility, which would be appropriately ring-fenced from other utility operations. The ring-fencing mechanism would allow the SB to take on the responsibility for the management of reliability planning and electricity procurement services.

To finance the day-to-day operations, the SB revenue requirement would be combined with that of the utility and consequently recovered through electricity rates. The SB would thus be able to recover its costs related to power procurement and its operations.

As an example, the largest electricity utility in Malaysia and Southeast Asia, Tenaga Nasional Berhad ("TNB")[39] comprises of five business entities: TNB Generation, SB, Grid System Operator, Transmission, and Distribution Network. The SB, along with the Grid System Operator, is set up as ring-fenced entities within TNB; the SB has separate accounts and IT infrastructure such as emails, and its operations and costs are clearly distinguished from those of the utility. That being said, the SB does share certain resources with the IOU which remain with the broader IOU; these include human resources, legal counsel, and the staff maintaining accounts and IT systems. TNB's SB entity recovers its costs using a tariff (i.e., rate-based recovery). A Revenue Cap regime and an Actual Cost regime are applied for SB's operating and generation costs, respectively.[40]

Under a revenue cap regime, an annual revenue requirement is set annually, whereas, under an actual cost regime, TNB recovers all actual costs. More specifically, the Actual Cost regime allows SB to pass on electricity procurement costs (e.g., from independent power producers, TNB Generation, capacity payments, etc.), including the actual cost of procuring electricity from various generators to Distribution. Said costs are ultimately passed onto the ratepayers.

6.2 Single buyer (outside)

In the case of an SB outside of the utility, it is required to set up a separate entity which is not associated with the utility. To finance the day-to-day operations, the SB's revenue requirement would be recovered from fees assessed on consumers' electricity bills. These fees would need to

[39] See the deliverable for Task 1.4.2, Section 5.3 for an introduction to the TNB SB.

[40] Ibid.

be approved by the PUC. Alternatively, if set up as a government agency, the SB operations can be financed through funds appropriated by the legislature.

In Ontario, for instance, prior to its merger with the Independent Electricity System Operator ("IESO"), the Ontario Power Authority ("OPA") was established in 2005 as an independent SB, and recovered a large portion of operation costs from market participants through Ontario Energy Board ("OEB") approved fees, as well as through the global adjustment mechanism, assessed on electricity consumer bills.[41] The global adjustment and settlement accounts kept track of the charges flowing between the OPA and the market administered by the IESO pertaining to demand response programs, non-utility generation, and regulated hydroelectric and nuclear generation, for instance; these accounts were settled by the IESO on an ongoing basis. The accounts also kept track of amounts pertaining to OPA contracts for generation and conservation/demand management, the Feed-in-Tariff ("FIT") program, and hydroelectric contract initiatives, amongst others, which were settled by the OPA monthly. As such, the settlements resulted in a balance of zero on a monthly basis.[42]

Further, similar to the OPA, the SB could establish internal funds to support certain types of projects. The OPA established the Conservation Fund and the Technology Development Fund to support electricity conservation initiatives and to support the development of technology aimed at improving electricity supply or conservation, respectively. Again, expenditures of projects associated with the two funds were recovered through the global adjustment mechanism.

As another example, the Illinois Power Agency ("IPA") was created in 2007 by the Public Act 95-0481 (SB 1592). Combined with the Public Utility Act ("PUA"), the IPA replaced the Illinois Action with a portfolio procurement process, with responsibilities including (but not limited to) the development of electricity procurement plans, conducting competitive procurement processes, developing and implementing procurement plans, and supplying electricity from IPA facilities at cost to municipal electric systems, governmental aggregators, or rural electric co-ops in Illinois.

From Fiscal Year 2010 onwards, the operations of IPA have solely been funded through the IPA Operations Fund; created as a special fund in the State Treasury, the IPA Operations Fund is subject to appropriation by the General Assembly.[43] Further, costs incurred in connection with the development and construction of a facility by the IPA, and thus subsequent operations and maintenance of said facility are funded through the IPA Facilities Fund.[44] Funds used from the IPA Facilities Fund are also subject to appropriation by the General Assembly.[45]

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[41] Ontario Power Authority. *Financial Statements: 2014 Annual Report.*

[42] Ibid.

[43] Illinois General Assembly. *Executive Branch (20 ILCS 3855/) Illinois Power Agency Act*. Web. March 16, 2018. <http://www.ilga.gov/legislation/ilcs/ilcs5.asp?ActID=2934&ChapterID=5>

[44] Ibid.

[45] Ibid.

7 Appendix A: Scope of work to which this deliverable responds

Task 1.6.5 Qualitative assessment of financing options for each ownership model

CONTRACTOR shall identify potential financing mechanisms of each ownership model, including an assessment of the cost and availability of each.

DELIVERABLE FOR TASK 1.6.5. CONTRACTOR shall provide all work related to providing a qualitative assessment of the financing options for each ownership model. CONTRACTOR shall provide an MS Word document and a PowerPoint summary summarizing the findings. CONTRACTOR shall submit deliverable for TASK 1.6.5 to the STATE for approval.

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Review of potential regulatory models that could be applied in Hawaii

A working paper prepared by London Economics International LLC with support from Meister Consultants Group for the State of Hawaii

August 20, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership and regulatory models to support the State in achieving its energy goals; this document is one of several working papers associated with that engagement. Five utility regulatory structures are reviewed in this memo based on the scope of work provided: (i) status quo; (ii) status quo with increased oversight; (iii) independent system operator; (iv) distribution-focused regulatory model; and (v) performance-based regulatory model. The Project Team also introduced a separate regulatory model for the Kauai Island Utility Cooperative ("KIUC") with lighter regulation than the status quo.

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List of acronyms

AIFI	Average Interruption Frequency Index
CAIDI	Customer Average Interruption Duration Index
Capex	Capital expenditure
Co-op	Cooperative
COS	Cost of Service
CPUC	California Public Utilities Commission
DBEDT	Hawaii Department of Business Economic Development and Tourism
DERs	Distributed energy resources
DR	Demand response
DSIP	Distributed System Implementation Plan
DSPP	Distributed System Platform Provider
DUOS	Distribution use of system
EIA	US Energy Information Administration
ERCOT	Electric Reliability Council of Texas
ESM	Earnings Sharing Mechanism
FERC	Federal Energy Regulatory Commission
HECO	Hawaiian Electric Company, Inc.
HEI	Hawaiian Electric Industries
HELCO	Hawaii Electric Light Company, Inc.
HERA	Hawaii Electricity Reliability Administrator
HRS	Hawaii Revised Statutes
HSEO	Hawaii State Energy Office
IDER	Integrated Distributed Energy Resources
IDSO	Independent distribution system operator
IOU	Investor-owned Utility
IPPs	Independent Power Producers
ISO	Independent System Operator
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company, Ltd.
MPUC	Maine Public Utilities Commission
NERC	North American Electric Reliability Corporation
NY PSC	New York Public Service Commission
OASIS	Open Access Same time Information System
OEB	Ontario Energy Board
Opex	Operating expenditure
Ofgem	Office of Gas and Electricity Markets
PBR	Performance-based Regulation
PIMs	Performance Incentive Mechanisms
PUC	Public Utilities Commission
RAM	Revenue Adjustment Mechanism
REV	Reforming the Energy Vision

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RIIO	Revenue = Incentives + Innovation + Outputs
ROE	Return on Equity
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization
RUS	Rural Utilities Services
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TFP	Total factor productivity
TIS	Texas Interconnected System
Totex	Total expenditure
UK	United Kingdom

Executive summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. The State of Hawaii is gearing up for the strengthening of its energy sector, targeting, among others, 100 percent renewable energy in its electricity sector by 2045. This working paper, which responds to Task 2.1.1 in the project scope of work, provides an overview of the various types of regulatory models and evaluates their features. We have also considered the high-level steps that would be necessary if other regulatory structures were to be implemented. A more detailed assessment of each regulatory model's technical, financial, and legal feasibility and steps will be discussed in the succeeding tasks.[1]

Based on the Project Team's preliminary work interaction with the stakeholders, a regulatory model should be able to achieve the State's energy goals and provide a level playing field to all market players. Moreover, the regulatory model should encourage the deployment of distributed energy resources and be able to support and take into consideration the underserved population of the State.

Five utility regulatory structures were reviewed based on the scope of work provided and our evaluation of various additional potential arrangements. These include: (i) status quo; (ii) status quo with increased oversight; (iii) independent system operator ("ISO"); (iv) distribution-focused regulatory model; and (v) performance-based regulation ("PBR") model. PBR comprises various mechanisms and could be used in different combinations. Therefore, for Hawaii, we have identified three (3) potential PBR options: (i) Light PBR; (ii) Conventional PBR; and (iii) Outcomes-based PBR.

- Light PBR would build upon the existing regulatory model and expand the current performance incentive mechanisms ("PIMs") to include other metrics that would enable the State to achieve its energy goals. The PIMs would also be symmetrical where utilities would both be rewarded and penalized for achieving and missing the agreed targets, respectively. Light PBR would use the same 3-year general rate cycle and also include the current earnings sharing mechanism ("ESM") where above threshold earnings would be shared with the customers.

- Conventional PBR would use a revenue cap. Rates would increase by an indexing formula based on an inflation and productivity factor during the 3-year regulatory period. This option would have the same expanded list of PIMs under Light PBR and continue to include the ESM. However, unlike the previous option, the ESM would be symmetrical and have a larger sharing percentage and deadband.

- Outcomes-based PBR, which is inspired from the United Kingdom's ("UK's") Revenue = Incentives + Innovation + Outputs ("RIIO") model, would focus on setting the outcomes

[1] See Section 1.3 for the list and description of Tasks related to this memo.

and providing the utilities the flexibility on how to achieve the results and what inputs to use to deliver them. The regulatory term under this option would be longer (at 5 years) to strengthen efficiency incentives and help manage the pace of rate increases for customers. This option would require more stringent monitoring and reporting requirements compared with the other two PBR options.

Figure 1. Public Utilities Commission's ("PUC") roles under each regulatory model

	Oversight responsibilities	Status quo	Status quo with increased oversight	ISO	Distribution-focused regulation	PBR
Generation	Monitors availability (generation)	PUC	HERA	ISO	PUC	PUC
	Approves fuel supply contracts		PUC	N/A		
	Approves PPAs and new generation builds			ISO		
	Determines resource needs	Utility	Utility and HERA	ISO		
	Approves resource planning	PUC	PUC	PUC		
Transmission	Monitors reliability (transmission)	PUC	HERA	ISO	PUC	PUC
	Ensures grid access (transmission)		HERA	ISO		
	Determines transmission investment needs	Utility	Utility	ISO	Utility	Utility
	Approves transmission investment needs	PUC	PUC	PUC	PUC	PUC
Distribution	Monitors reliability (distribution)	PUC	HERA	ISO	DSO	PUC
	Ensures grid access (distribution)		HERA	PUC	DSO	
	Monitors availability (DER on distribution)	Utility	Utility	Utility	DSPP/DSO	Utility
	Monitors service quality	PUC	PUC	PUC	PUC	PUC
	Determines distribution investment needs	Utility	Utility	Utility	DSPP/DSO	Utility
	Approves distribution investments needs	PUC	PUC	PUC	PUC	PUC
Cross cutting	Regulates rates	PUC	PUC	PUC (T&D)	PUC	PUC
	Approves financial transactions (e.g., issuance of stocks etc.)			PUC		
	Approves large capital investments					

Note:
ISO – Independent System Operator; PBR – Performance-based Regulation; HERA – Hawaii Electricity Reliability Administrator; DSPP – Distribution System Platform Provider; DSO – Distribution System Operator; G – Generation; T&D – Transmission, and distribution; PPA- Power Purchase Agreements

Role of PUC under the three variants of PBR are the same.

Finally, the Project Team also considered a lighter regulation model for Kauai Island Utility Cooperative ("KIUC"). Given the difference in business models for KIUC compared with other Hawaii utilities, this is a potentially viable regulatory framework that will be explored further in future deliverables.

Some of these regulatory models (such as the status quo with increased oversight, ISO, and distribution-focused regulatory model) require delegating some of the current responsibilities of the Public Utilities Commission ("PUC") to an independent entity while others such as the PBR would require additional oversight from the PUC. Moreover, some of these regulatory models would entail certain changes in the responsibilities of the incumbent utilities and in the electricity sector value chain. For instance, under the ISO and distributed-focused regulatory model, an independent entity would oversee the day-to-day operations of the grid although the utilities would still own the network assets. Figure 1 shows a summary matrix of the PUC's oversight responsibilities under each regulatory model.

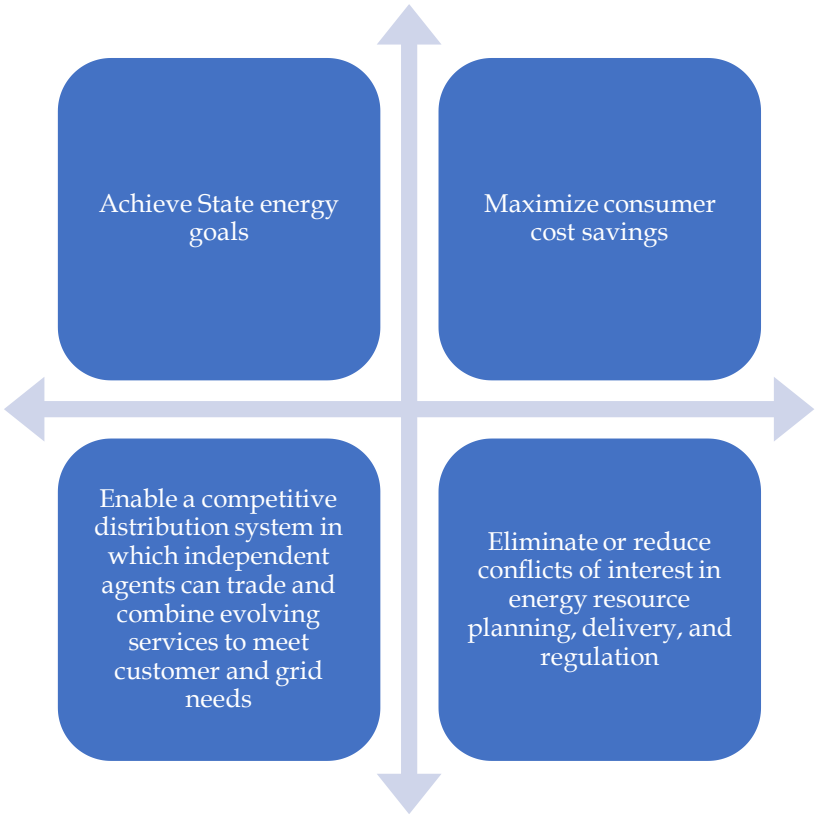
1 Introduction and Scope

1.1 Project description

DBEDT was directed by the State legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. LEI, through a competitive sealed proposals procurement,[2] was contracted to perform this study.[3]

The project aims to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[4] (Figure 2).

Figure 2. State's key criteria in evaluating the models



Source: Scope of Services under Contract No. 65595.

[2] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[3] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[4] House Bill No. 1700 Relating to the State Budget.

The study will help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the State. Moreover, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[5]

1.2 Relevance of this deliverable relative to others in the project

This deliverable is responsive to Task 2.1.1 in the project scope of work. It introduces the various types of regulatory models and evaluates their characteristics. Also, multiple aspects of the regulatory models themselves will be further explored in subsequent deliverables. These deliverables include:

- assessment of current markets under each regulatory model, including a case study, analysis, and conclusions (Task 2.2.2);
- assessment (high-level) of the technical, financial, and legal feasibility of each regulatory model (Task 2.2.3);
- estimation of the stranded costs for each regulatory model (Task 2.2.4);
- solicitation of public input from each island currently served by an electric utility on the results of Task 2.1.1 through 2.2.4 (Task 2.2.5);
- identification and recommendation for the three most beneficial regulatory models for further consideration (Task 2.2.6);
- identification of steps, costs, and projected timelines, for change from the current regulatory model to the recommended regulatory models (Task 2.3.1);
- analysis of Hawaii law and history to determine the regulatory and legislative changes needed to implement the recommended regulatory models (Task 2.3.2);
- identification and assessment of the impact of financial and operational risks for different stakeholders under each regulatory model (Task 2.3.3);
- evaluation of how each recommended model impacts State agencies staffing and stakeholders (Task 2.3.4);
- estimation of potential for each model to increase distributed energy resources (Task 2.4.1); and

[5] Hawaii Contract No. 65595. Scope of Services.

- evaluation of revenue requirements, system average retail rates, risks to utility valuations, and funding mechanisms for each regulatory model (Task 2.5).

1.3 Future refinements

As noted earlier, this deliverable is an overview of the different regulatory models and, as such, the results of our analysis are subject to further refinement and change as the project moves forward and additional information becomes available (namely, inputs from the stakeholder groups and results of the quantitative analysis and case studies). LEI will provide case studies in some of the deliverables (if applicable) to highlight the essential features of the different regulatory models and critical issues and lessons from other jurisdictions or utilities. Furthermore, the project will provide various opportunities for stakeholder inputs and participation. LEI will engage a wide range of stakeholders and perspectives across all islands through a series of facilitated dialogues, one-on-one meetings, and workshops.[6]

[6] A series of community meetings across the State was held in June 2018 in Hawaii. The workshops provided opportunities for the attendees, as well as online participants, to hear from key stakeholders in the energy policy discussion and provide inputs to the study through the small group discussions.

2 Key priorities of a regulatory model

The key priorities of a regulatory model will balance two aspects: (1) commonly accepted principles and (2) views of stakeholders.

2.1 Commonly accepted principles

As shown in Figure 3, there are five widely accepted principles in establishing a general regulatory regime and in setting rates/tariffs:[7]

- ***Incentives compatibility***: Ratemaking should provide appropriate incentives to both companies and customers (although some natural conflict may occur, and tradeoffs may be needed). According to the renowned economist Alfred E. Kahn, "*the central institutional questions related to suitable regulatory regimes have to do with the nature and adequacy of the incentives*." [8] Incentive compatibility involves providing a suitable framework to encourage utilities to reduce costs while ensuring reliable, safe, and quality service for customers. Moreover, a sound regime should discourage inefficient consumption on the part of customers. An incentives-compatible scheme is one in which the interests of the regulated company (and its shareholders and management) and ratepayers are mostly aligned.

- ***Financial stability and fair (commercially reasonable) rate of return***: Rates must be set at a level which enables the utility to meet its statutory obligations to serve while earning a commercially reasonable return (which continues to attract investors given the business risks) and generating enough cash flow to support necessary investment.

- ***Administrative simplicity and transparency***: Rates should be straightforward enough for customers to understand; customers should be able to calculate their monthly bills themselves and to know why the rate is calculated in the prescribed fashion. Complex ratemaking approaches increase costs to consumers. For example, an increase in accounting and billing costs (caused by complex ratemaking approaches) may result in more time being spent proving that the rates are indeed fair. As a result of this factor, ratemaking mechanisms should also be appropriate for the jurisdiction to which they are applied; complex rates in regions with inadequate data and understaffed regulators may be impossible to administer. However, it is worth noting that high levels of DER penetration are likely to make equitable cost allocation more complex and expensive even

[7] For more information, see: Bonbright, Danielson and Kamerschen. *Principles of Public Utility Rates*, Public Utility Reports Inc, Arlington, VA. 1988; Bonbright, Danielson. *Principles of Public Utility Rates*, Public Utility Reports Inc, Arlington. 1961. Page 290-94); Weston, Fredrick. "Principles of Rate Design." 1999. www.raponline.org); and Woolf, Tim and Julie Michals. "Performance-Based Ratemaking: Opportunities and Risks in a Competitive Electricity Industry." *The Electricity Journal* 8.8 (October 1995).

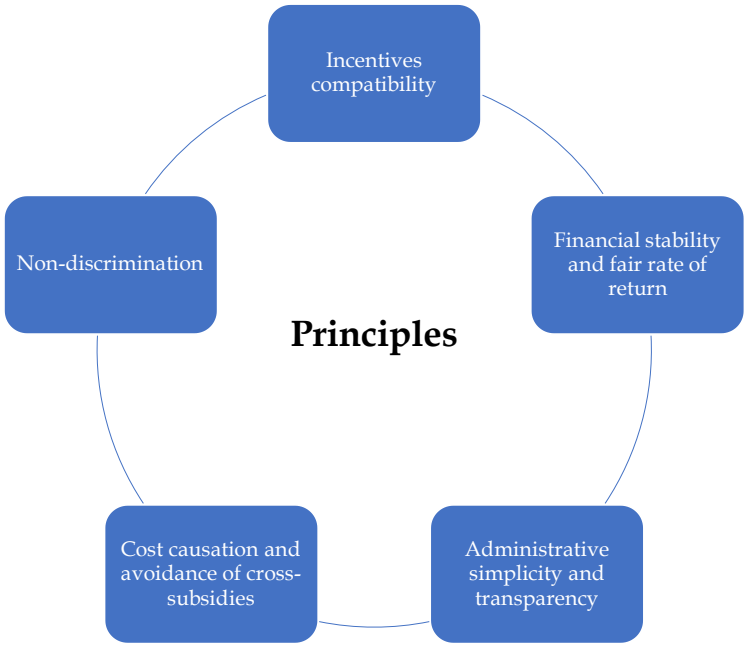
[8] Kahn, A.E. *The Economics of Regulation: Principles and Institutions*. Volume 1 (1970) and Volume 2 (1971). Wiley: New York (1970, 1971).

under the status quo. Sophisticated rates could potentially both include more effective price signals and reflect the appropriate costs in a future grid.

- ***Cost causation and avoidance of cross-subsidies***: In order to achieve the most efficient patterns of consumptions, economic theory states that the customers that cause a cost to be incurred should pay that cost. When cost causation is identified, then cross-subsidies (either between or within customer classes) can be avoided, re-aligning customers' incentives regarding consumption and their willingness to pay. Policy requirements may sometimes override this objective; however, in such cases, it must then be recognized that there will be some loss of efficiency. In addition, providing services to the grid by prosumers will need to be balanced with more simplified rates.

- ***Non-discrimination***: Similarly situated customers should face similar terms and conditions. It is true that in a competitive marketplace, customers have the opportunity to change suppliers if better terms are available, while customers of a monopolistic utility do not have this alternative. However, in theory, competition will ensure that customers with similar tastes and preferences face a same set of choices, while in a regulated environment, such an outcome is assured only through enforcing non-discrimination in ratemaking. As customers have more choices in terms of the services they receive from the grid or provide to it, ratemaking must evolve to reflect the economic decision faced by customers.

Figure 3. Five commonly accepted principles



When deciding upon a regulatory regime or a change in regime, the above principles need to be assessed collectively. PBR regimes, as will be discussed in Section 3.5, could encourage utilities to reduce costs, but need to include mechanisms that would ensure a reliable, safe, and appropriate level of quality of service for customers. Any regulatory regime must offer an

opportunity for a reasonably efficient utility to earn its commercially reasonable rate of return. PBR provides an opportunity for utilities that are more efficient or meet specific policy goal effectively to be rewarded in the form of higher returns. However, the targets set for efficiency need to be balanced against the financial viability of the utility and consideration of costs that are within management's control. PBR also provides a mechanism for customers to benefit – through the constant, implicit "sharing" of efficiency gains via the formula, as well as through any other incremental earnings-sharing mechanism. However, an earnings-sharing mechanism that captures efficiency gains for customers would dull incentives for the utility. Therefore, as mentioned previously, a careful balancing of considerations is required.

2.2 According to the stakeholders

Based on the inputs from DBEDT and other stakeholders, the key priorities in a regulatory model include helping to achieve the State's energy goals, ensuring that utilities prudently recover their incurred costs, providing certainty by setting a timeline for its decision-making (among others), and respecting county-level differences. These inputs came from the Project Team's one-on-one meetings with stakeholders, workshops from the Verge Conference, and stakeholder outreach meetings conducted in October 2017. The Project Team had additional stakeholder outreach in June 2018. The discussion in this section will be explored further in Task 2.2.5 (Stakeholder Outreach Report).

DBEDT noted that a regulatory model should help to achieve the Energy Policy Directives, including:[9]

1. diversifying its energy portfolio;
2. connecting and modernizing its grids;
3. balancing technical, economic, environmental, and cultural considerations;
4. leveraging its position as an innovation test bed; and
5. promoting an efficient marketplace that benefits producers and consumers.

Particularly, DBEDT emphasized that the regulatory model needs to be able to capture various considerations in the third point of the Energy Policy Directives, which is to balance technical, economic, environmental, and cultural factors, beyond a least "economic" cost approach. Moreover, the regulatory model should address barriers to entry for new suppliers and provide opportunities for new types of technology and services (e.g., micro-grids, virtual power plants) to enter the market. The regulatory model needs to enable the full transition of the existing

[9] HESO. *Energy Policy: State of Hawaii Energy Policy Directives*. Website. <http://energy.hawaii.gov/energypolicy>

marketplace to a new more efficient marketplace and not just the incremental benefit-cost ratio of an individual step.[10]

Discussions in the Verge Conference session, one-on-one meetings, community outreach (June 2018), and email exchanges revealed that other stakeholders had the following concerns of individual stakeholders[11] on the existing regulatory model:

- current rate recovery model creates incentives for the utility that do not align with customer priorities;
- pricing signals should be fixed, and there should be a way to allow project developers to recover costs;
- some of the current regulations are outdated and do not sufficiently encourage business growth and utility innovation;
- slow regulatory procedures and process; and
- there is a need to reduce unnecessary regulation by the PUC on KIUC.

Therefore, stakeholders want to see the policies and regulations that: [12]

- are consistent and efficient;
- take the most vulnerable or underserved population into account;
- provide greater mechanisms and incentives to develop and innovate the industry;
- allow for more utility innovation and quicker adoption of new technologies;
- enable more renewables to be brought on the grid;
- align interests between community priorities and utility incentives;
- provide an independent entity or authority managing reliability or interconnection issues;

[10] DEBDT's reply to LEI's question. Schwing, Michael D. RE: Key priorities of a regulatory model. Sent: Monday, February 26, 2018 1:48 PM.

[11] These are comments from different stakeholders, but not necessarily consensus points.

[12] Summarized based on stakeholders' comments on regulatory models in the stakeholders' engagement process, including kick-off meeting in May 2017, VERGE Hawaii conference in June 2017, and community meetings in October 2017.

- foster infrastructure development to facilitate the broader use of distributed energy resources; and

- adapt to a rapidly changing energy landscape.

The regulatory models that the Project Team will review under Task 2 will hopefully address these concerns and discuss the priorities flagged by DBEDT and stakeholders.

3 Other potential regulatory models

A regulatory framework refers to the rule-making activity of the State or its regulatory agencies. Government entities involved in the regulatory process include a range of institutions such as those tasked with policy-making responsibilities by the executive branch (such as ministries or departments), creating and enforcing rules for implementation (such as regulatory bodies), and other government agencies responsible for different but related tasks.

In addition to the status quo, seven regulatory models are explored under Task 2 and briefly discussed in this paper. These are:

1. Status quo with increased oversight (or with the Hawaii Electricity Reliability Administrator ("HERA"));
2. ISO;
3. Distribution-focused regulatory model; and
4. Light PBR;
5. Conventional PBR;
6. Outcomes-based PBR; and
7. Lighter regulation for KIUC.

In some of these models, the oversight roles of the PUC would be reduced while it would have more responsibilities in others. For example, under the status quo with increased oversight, the grid access and reliability responsibilities would be executed by another entity instead of the PUC. On the other hand, under the PBR model, the PUC would have additional responsibilities, which include identifying and determining performance metrics and rewards/penalties that would be implemented, reviewing and ensuring that the forecasted revenue requirements are appropriate, and monitoring and evaluating the performance of the utilities.

In many cases, it is likely that additional resources are needed to implement these potential regulatory models. For instance, under the DSPP model, investments in new technologies are required to establish the DSPP and set up the required platforms.[13] Likewise, more comprehensive mechanisms of PBR (see Section 3.5.1 for a discussion on this) require collecting and employing multi-period information and data samples covering multiple companies. The availability of reliable, comparable, and accurate data for the industry as a whole and the utilization of "best practice" forecasting tools could improve the functionality of the PBR process. Outside support (e.g., from industry experts and consultants)) is common in other jurisdictions that have implemented PBR. This could assist the regulator in reviewing and confirming the

[13] See Task 1.1.4 (Assessment of Future Needs for Generation, Transmission, and Distribution Infrastructure in Each County) for a more detailed discussion on infrastructure needs under a distribution-focused model.

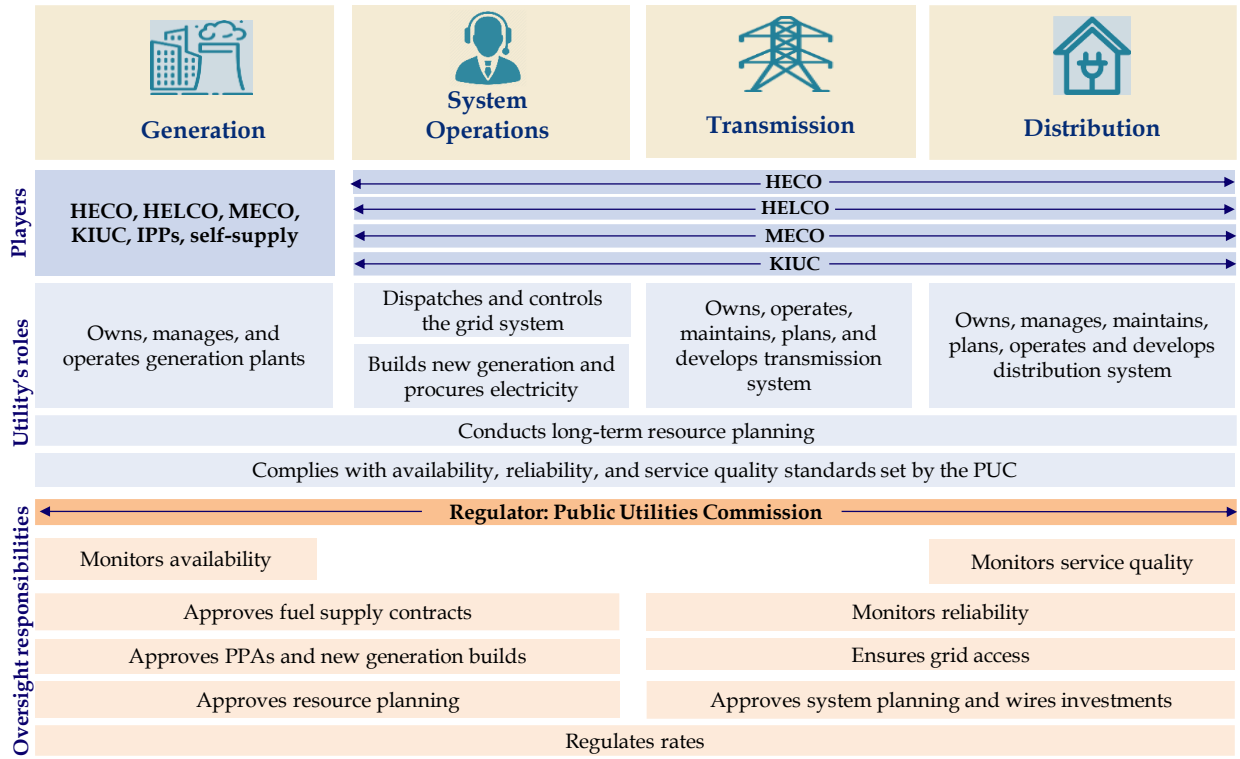
appropriateness of the PBR plan filed by the utilities. A more thorough discussion of the advantages and disadvantages of the different models will be discussed in Task 2.2.1.

3.1 Overview of the regulatory structure in Hawaii

The State of Hawaii is served by vertically integrated utilities, namely the Hawaii Electric Light Company, Inc. ("HELCO"), Maui Electric Company, Ltd. ("MECO"), Hawaiian Electric Company, Inc. ("HECO") (combined, these three subsidiaries will be called "HECO Companies" in this memo), and KIUC. The HECO Companies own most of the generation, transmission, and distribution assets in the counties that they serve. The Hawaii Electric Industries subsidiaries, including HECO, MECO, and HELCO, are investor-owned utilities ("IOU") that supply power to approximately 95% of Hawaii's population. On the other hand, KIUC is the only cooperative ("co-op") in the State.

There are three main institutional entities in the Hawaii electricity market – the State Legislature, PUC, and the Hawaii State Energy Office ("HSEO"). The HECO Companies and KIUC are regulated by the PUC.

Figure 4. Graphical depiction of the electric structure and oversight in the status quo model



The PUC is the regulatory body that regulates the electric utilities in Hawaii. It is enforced to regulate utilities' rates and ratemaking procedures, approve mergers and acquisitions of utilities, authorize construction of transmission lines, monitor electric reliability, and assess conditions of each utility regarding how it operates and its issuance of stocks, bonds and disposition of

proceeds.[14] The PUC's current roles and responsibilities will be discussed in detail in Task 2.1.2 (Existing Regulatory Model in Hawaii). On the other hand, HSEO which is under DBEDT advises the State government which sets the energy policies. Figure 4 illustrates the current electric structure and oversight in the State.

Currently, electricity rates in the state are determined through a cost of service ("COS") approach that includes some components associated with PBR, namely: multi-year rate plan, ESMs between the utility and the customers for the HECO Companies, revenue cap, and decoupling. Task 2.1.2 (Existing Regulatory Model in Hawaii) will have a more detailed discussion on the current ratemaking process. Recently, the Governor of Hawaii signed the Ratepayer Protection Act (Senate Bill 2939) into law. It directed the PUC to investigate performance incentives and penalty mechanisms. Section 3.5.3 will provide a brief overview of this.

3.2 Status quo with increased oversight

Under the status quo with increased oversight model, the HERA is assumed to be implemented. The HERA was enabled by the Hawaii State legislation (Act 166) in 2012. HERA was envisioned to ensure that the State's clean energy goals would be achieved by implementing reliability standards across the electric value chain and providing fair grid access to generators:

> "*The legislature finds that the capability and accessibility of Hawaii's electrical system must be aligned with both the State's ambitious renewable portfolio standard mandate and the various technologies that generate electricity at both the distribution and transmission levels. ... However, in order to ensure that these types of generation resources can be integrated into the island grids, the technical, operational, and regulatory issues associated with running the electrical system must be considered and addressed in order to achieve the full potential of local renewable energy production. The implementation of formal reliability standards to govern all segments of the electric power system and to ensure fair and transparent grid access is a critical part of achieving Hawaii's lofty, clean energy requirements. Also, clear regulatory oversight of the State's grids will ensure system reliability, resiliency, and accountability.*"[15]

The Hawaii PUC was authorized to enforce reliability standards and oversee grid access and interconnection issues and contract these functions out.[16] The PUC may contract with a person, business, or organization (except for a public utility) for the performance of HERA's functions.[17]

HRS 269-146 ordered that the Hawaii electricity reliability surcharge shall be collected to support the operations of HERA if needed. The Hawaii electricity reliability surcharge shall be collected from "*all utilities, persons, businesses, or entities connecting to the Hawaii electric system, or any other*

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[14] For details, please refer to Hawaii Revised Statues ("HRS") Chapter 269 – Public Utilities Commission.

[15] Hawaii Senate Bill 2787. 2012. Website. <https://www.capitol.hawaii.gov/session2012/bills/SB2787_CD1_.htm>

[16] Hawaii House Bill 2525. 2012.

[17] HRS 269-147.

user, owner, or operator of any electric element that is a part of interconnection on the Hawaii electric system."[18] Moreover, the Hawaii PUC may allow *"an electric utility to recover appropriate and reasonable costs under the Hawaii electricity reliability surcharge for any interconnection to the Hawaii electric system, including interconnection studies and other analysis associated with studying the impact or necessary infrastructure and operational requirements needed to reliably interconnect a generator, as well as from electric utility customers through a surcharge or assessment subject to review and approval by the commission."*[19]

The law prescribes that HERA should report to the Hawaii PUC each year on the status of its operations, financial position, and a projected operating budget for the following fiscal year.[20] The law also requires that staff members should have "*appropriate skills and expertise to offer prudent and reasonable recommendations on the development of reliability standards and interconnection requirements*."

Moreover, HRS 269-148 emphasized that staff members should have the appropriate level of independence and the ability to fairly and impartially review matters concerning interconnection.[21]

Currently, there is no HERA in place in the State. However, a study on the structure of HERA has already been commissioned by the Mayor's Office of Economic Development of Maui County. The Study,[22] which was published on August 25, 2017, assessed the initial structure for HERA. According to the Study, the State might benefit from independent planning organizations that could provide pre-emptive reliability standards to accommodate Hawaii's Renewable Portfolio Standards ("RPS"), and such a function could be overseen by a HERA-type organization. It also stated that a HERA could give similar oversight for the interconnection application processes and timelines. However, the Study concluded that it is difficult to demonstrate that the costs that would be incurred to establish a separate entity would be covered by savings from changes in interconnection or reliability.

With such a challenge, an alternative is a "light" HERA, which could be designed as an ombudsman, an appeals body focused on hosting capacity and interconnection. It would have the technical capability to set target timeframes and standard models for calculating interconnection costs convened when a customer wants to challenge utility interconnection behavior or lack of hosting capacity transparency. HERA would only investigate if the customer has exhausted utility internal appeals processes. HERA also drafts orders for the PUC to sign in

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[18] HRS 269-146.

[19] Ibid.

[20] HRS 269-149.

[21] Ibid.

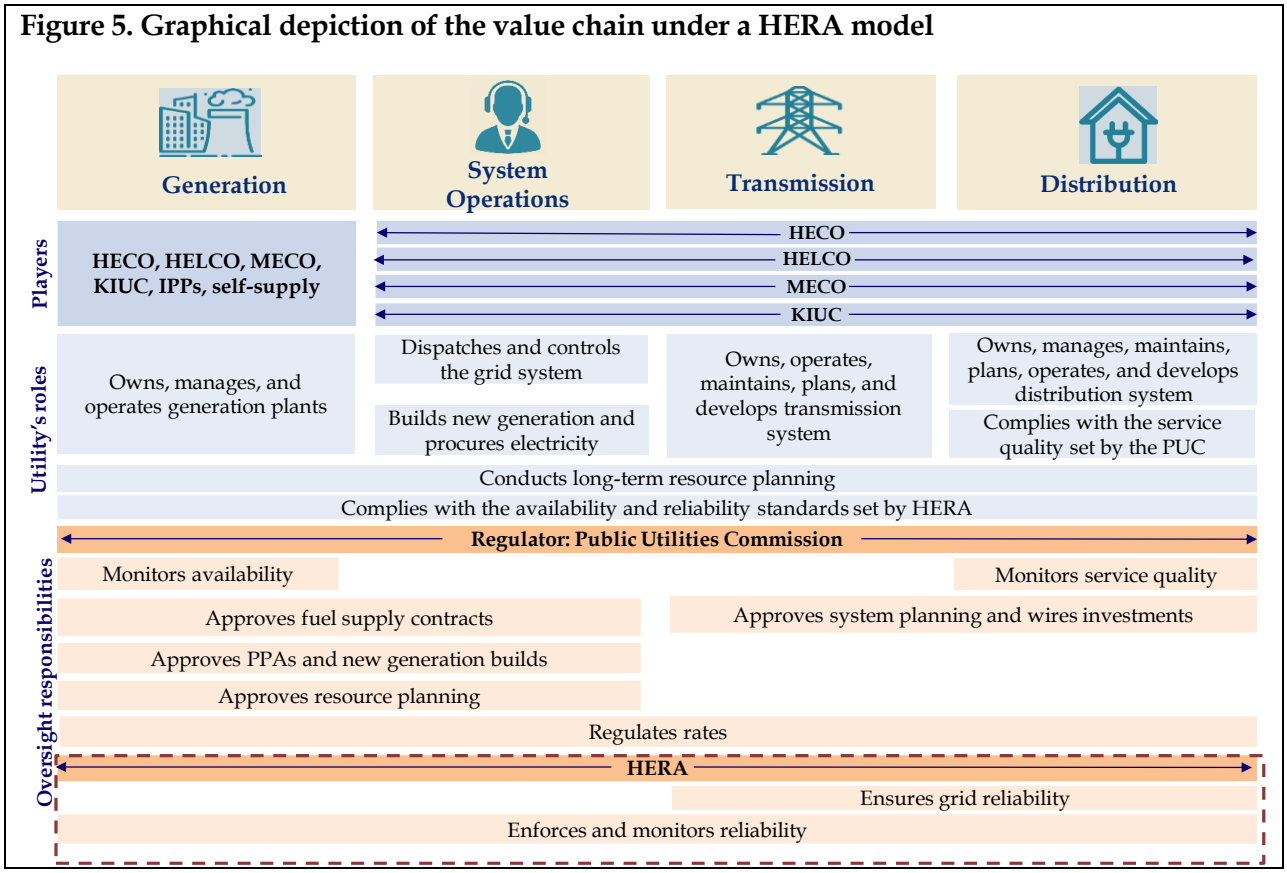
[22] Mayor's Office of Economic Development, Energy Commissioner, DKK, and SES. *Comparing the Structure and Function of a HERA to an ISO: Report and Task Analysis for use by the County of Maui.* August 25, 2017.

the event that it finds utility behaving arbitrarily. However, the intent is that referral to HERA would serve as an incentive for utility and customer to settle differences.

3.2.1 Oversight under a HERA model

The increased oversight from HERA would not change the current structure of the electric value chain. Utilities would continue to operate the transmission and distribution network under this regulatory model. The PUC's role on grid access and reliability would be transferred to HERA as shown in Figure 5.

Figure 5. Graphical depiction of the value chain under a HERA model



3.2.2 Jurisdictions with a HERA model

HERA does not currently exist in Hawaii, but it is a concept that the Act 166, Session Laws of Hawaii 2012, authorized the PUC to develop, adopt, and be tasked to enforce reliability standards and interconnection requirements. A comparable entity is the North American Electric Reliability Corporation ("NERC") which is the electric reliability organization for North America, responsible for developing and enforcing mandatory electric reliability standards as overseen by the Federal Energy Regulatory Commission ("FERC"). NERC oversees both traditionally regulated and liberalized power markets. NERC was formed as a voluntary multi-utility response to the Northeast blackout of 1965. Forty years later, following the 2003 blackout, a US-Canadian Power System Outage Task Force was convened and made "recommendations regarding

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measures to reduce the risk of future power outages and the scope of any that do occur."[23] The transition to mandatory reliability standards then became necessary.

HERA and NERC have some similar features. First, both are a not-for-profit regulatory authority. Second, they have the same mission of ensuring the reliability and security of the grid. Third, both are directed to develop and enforce reliability standards. Lastly, HERA and NERC are subject to the oversight of the Commission (e.g., PUC for HERA and FERC for NERC).

3.3 Independent system operator

An independent system operator ("ISO") or a regional transmission organization ("RTO") is an independent, membership-based, non-profit organization that ensures reliability and uses bid-based markets to determine economic dispatch for wholesale electric power.[24] The concept of an ISO grew out of Orders Nos. 888/889 and subsequently the concept of RTO was introduced in Order No. 2000 from the FERC. More specifically, the creation of new institutions such as RTOs/ISOs was part of the restructuring process to address reliability through coordinated transmission planning while also facilitating open access. FERC, via Order 2000,[25] encouraged the voluntary formation of RTOs to administer the transmission grid on a regional basis throughout North America. In the same Order, FERC noted:

> "*Regional institutions can address the operational and reliability issues now confronting the industry, and eliminate any residual discrimination in transmission services that can occur when the operation of the transmission system remains in the control of a vertically integrated utility. Appropriate regional transmission institutions could: (1) improve efficiencies in transmission grid management; (2) improve grid reliability; (3) remove remaining opportunities for discriminatory transmission practices; (4) improve market performance; and (5) facilitate lighter handed regulation*."[26]

An ISO structure typically aims to assure reliability, which requires collaboration on the part of ISO, transmission owners and electricity utilities. This is ensured through the coordination of existing system components and processes to guarantee delivery of electricity upon demand, cooperation in monitoring and coordinating generation and transmission, communications and information sharing among all system operators to identify and isolate problems as they occur, and commitment by all electric utilities to continuously coordinate, cooperate, and communicate to protect and ensure system balance.

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[23] Dawson, Kelly and Levi McAlister. "Restoring Faith in the Bulk-Power System: An early Assessment of Mandatory Reliability Standards." *The Electricity Journal* 23.2 (March 2010): Page 19-20.

[24] EIA. *Today in Energy*. Website. Access Date: March 22, 2018. <https://www.eia.gov/todayinenergy/detail.php?id=790>.

[25] FERC. *Order No. 2000 - Regional Transmission Organizations*. Docket No. RM99-2-000. December 20, 1999.

[26] United States of America 90 Ferc ¶ 61,201 Federal Energy., Website. Access Date: August 07, 2018. <http://www.ferc.gov/legal/maj-ord-reg/land-docs/2000A.pdf>

In order to maintain reliability, certain responsibilities are performed by the ISO, while others remain with transmission owners and, as such, it may be essential to identify appropriate ISO functions and transmission owner functions respectively. ISO functions may include operational control of the transmission system, security coordinator for the region, administration of the ISO tariff, operation of the Open Access Same time Information System ("OASIS"),[27] allocation of available transfer capability, provision or coordination of ancillary services, involvement in transmission planning, implementation of congestion management procedures, coordination of transmission and generation, and maintenance scheduling.[28] On the other hand, transmission owners are responsible for owning, operating, and maintaining transmission facilities, conducting power system analysis and transmission planning studies, and constructing new transmission facilities.

In Hawaii, under this model, the utilities would still own and ratebase their transmission assets and pass the day-to-day coordination of flows of the transmission system to the ISO. In line with the minimum characteristics of an RTO as described in Order No. 2000, the potential ISO in Hawaii would have:

- independence;
- scope and regional configuration;
- operational authority; and
- responsibility for short-term reliability.[29]

In general, the governance structure of an ISO in other jurisdictions is two-tiered—the ISO Board and the Members Committee. The highest governing body is generally the Board of Managers, who have no affiliation with or financial stake in any ISO market participant. The number of board members varies across ISOs. For instance, in California ISO, there are five governors on its Board[30] while the Electric Reliability Council of Texas ("ERCOT") has 15 voting members and one non-voting member in its board of directors.[31] Meanwhile, PJM's board is composed of nine voting members plus the Chief Executive Officer or President who is a non-voting member.

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[27] OASIS provides information about transmission capability and a process for requesting transmission service.

[28] Ibid, page 323.

[29] FERC. Regional Transmission Organizations (Issued December 20, 1999) (Docket No. RM99-2-000; Order No. 2000), page 151.

[30] CAISO. *Board Selection Policy.* June 13, 2016. <http://www.caiso.com/Documents/BoardSelectionPolicy.pdf>.

[31] ERCOT. *ERCOT Quick Facts.* <http://www.ercot.com/content/wcm/lists/144926/ERCOT_Quick_Facts_41018.pdf>

Like other ISOs, PJM's Board oversees the ISO's operations, approves budget and staffing, and approves changes to market rules. In addition, the Board is responsible for the ISO's safety and reliability, as well as ensuring competitive and nondiscriminatory electric power markets. In PJM, the Board is advised by stakeholder groups and advisory committees that recommend changes to market rules and operating guides. For PJM, the voting Board members are elected for three-year staggered terms by the Members Committee.[32] The Members Committee consists of five sectors representing generation owners, transmission owners, electric distributors, other suppliers, and end-user customers.[33]

Meanwhile, for California ISO, a search firm chosen by the ISO is responsible for seeking out candidates for consideration by the Board Nominee Review Committee.[34] The Board Nominee Review Committee is composed of 36 members with each representing one of six member-classes that include transmission owners, end-users and retail energy providers, public interest groups, alternative energy providers, transmission-dependent utilities, and generators and marketers.[35] This committee ranks each candidate in descending order, and the ISO forwards the list of candidates (with ranking) to the Governor of the State of California for consideration. [36] Appointees are subject to confirmation by the state Senate, as outlined in the Public Utilities and Government Codes.[37] Similar to the PJM Board, the board of California ISO reviews and approves the annual ISO budget, shapes policies and approves grid planning and market design changes.[38]

As a not-for-profit company, an ISO funds the services it provides by collecting fees from the market participants and customers that use regional transmission services.[39] The service rates are set at a level that let the ISO recover operating costs, while the amount is determined each year through the budget process which includes a robust external stakeholder review process. After the approval of the budgets by the independent Board of Directors, they are filed with FERC.[40]

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[32] PJM. Governance. Website. Access Date: April 20, 2018. <https://learn.pjm.com/pjm-structure/governance.aspx>

[33] PJM Governance Fact Sheet. Website. Access Date: April 20, 2018. <https://learn.pjm.com/-/media/about-pjm/newsroom/fact-sheets/governance-fact-sheet.ashx>

[34] California ISO. *Board Selection Policy Version #4.4*. 2016. Page 1.

[35] Ibid, page 3 - 4.

[36] Ibid, page 4.

[37] Ibid, page 4.

[38] California ISO. The Board of Governors guides our direction. Website. Access Date: July 11, 2018. <http://www.caiso.com/informed/Pages/BoardCommittees/Default.aspx>

[39] ISO-NE. The ISO's Funding and Budgeting Process. Website. Access Date: April 20, 2018. <https://www.iso-ne.com/about/what-we-do/in-depth/the-iso-funding-and-budgeting-process>

[40] ISO-NE. The ISO's Funding and Budgeting Process. Website. Access Date: April 20, 2018. <https://www.iso-ne.com/about/what-we-do/in-depth/the-iso-funding-and-budgeting-process>

Since Hawaii is not within FERC's public utility-related statutory authority, an ISO could report to the Hawaii PUC, similar to how ERCOT does it—by reporting to the Public Utility Commission of Texas.

Maui County: Guernsey study recommended the ISO/ RTO model

Tasked by the County of Maui, Guernsey completed an options analysis for electrical utility service within the County and released the report in December 2015. The study suggested the ISO/ RTO regulatory model for Maui County because of the following advantages:

- ***little physical infrastructure:*** ISO/ RTO acquires existing dispatch, monitoring and control equipment, but the great majority of generation assets, transmission and distribution wires remain with MECO;
- ***quickest implementation:*** given enough political willpower this route could be completed much more quickly than a negotiated sale or condemnation of the MECO assets;
- ***implementable regardless of potential merger:*** this approach can be implemented regardless of the outcome of HEI/NextEra merger; and,
- ***promoting competition and transparency:*** this approach promotes competition by providing clear price signals and market transparency so that power producers of all types can make rational economic decisions; this approach also optimizes transmission planning such that all power producers are incorporated into planning and infrastructure improvement efforts.

Note: While LEI quotes the findings here, LEI does not necessarily endorse this approach.

Source: Guernsey. *County of Maui: Analysis of Alternative Forms of Ownership and Alternative Business Models for Maui County's Electric Utility Company*. December 23, 2015.

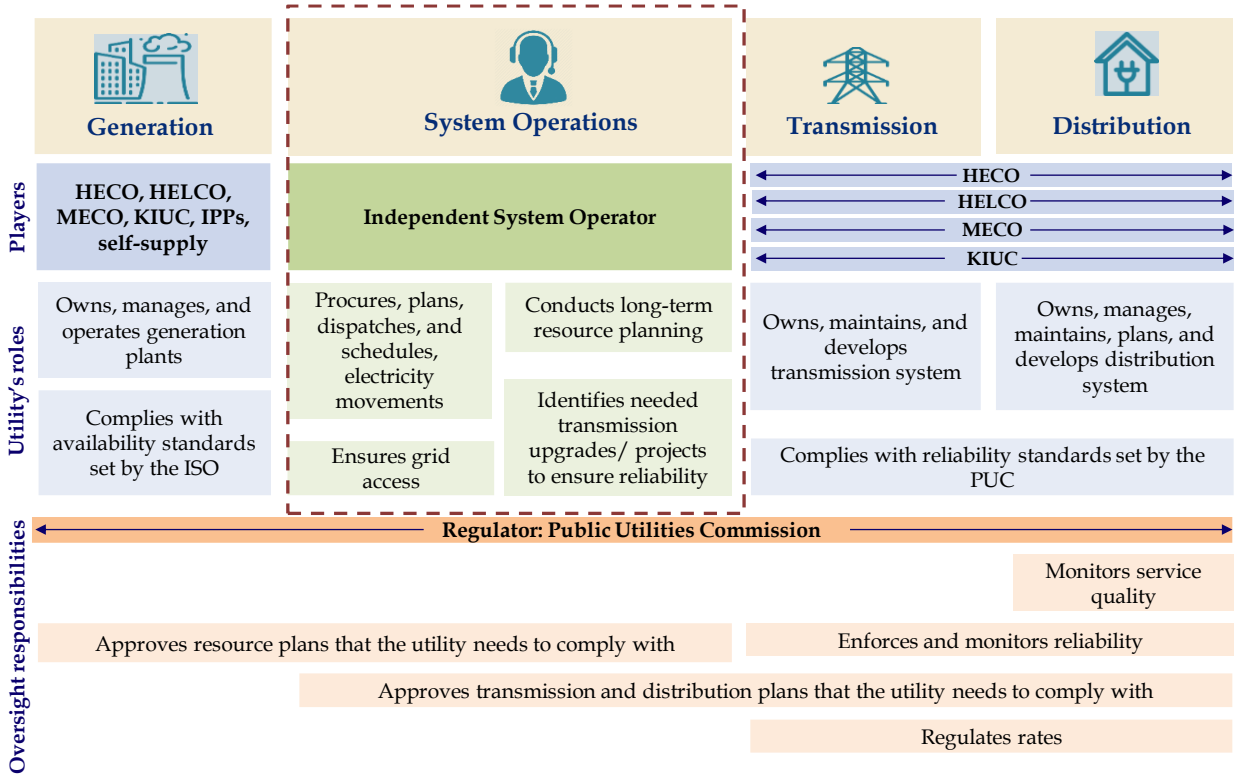
Although Hawaii is outside of FERC's and NERC's jurisdiction, an ISO or RTO could be formed in the State without participating in interstate commerce to accomplish the objective of system planning and dispatch. The box above enumerates the advantages of the ISO/RTO model, based on the study undertaken by Guernsey for the County of Maui in 2015.

3.3.1 Oversight under an ISO model

Under the ISO model, utilities continue to own and maintain the transmission and distribution system. However, utilities yield their functions of system planning, dispatch, and day-to-day operations to the ISO. Under an ISO model, the incumbent utility could either retain its generation assets or divest them. In contrast to the status quo, this change allows independent power producers ("IPPs") to compete with the incumbent vertically integrated utilities on price in the wholesale market.

The PUC's oversight on resource planning, power purchase agreements, utility's transactions, significant capital expenditure, service quality, and rates would remain the same. However, the tasks on reliability and long-term resource planning would be delegated to the ISO. The utility's previous role of coordinating movements of electricity would be transferred to the ISO as well, as shown in Figure 6.

Figure 6. Graphical depiction of the value chain under an ISO model



3.3.2 Jurisdictions in the US under an ISO/RTO structure

Currently, there are nine ISOs/RTOs in North America as shown in

Figure 7 and Figure 8. These include Alberta, California, Ontario, New York, Midcontinent ISO, New England, PJM Interconnection, Southwest Power Pool, and ERCOT. A case study of an ISO will be discussed in detail in Task 2.2.2.

Figure 7. RTOs/ISOs in North America

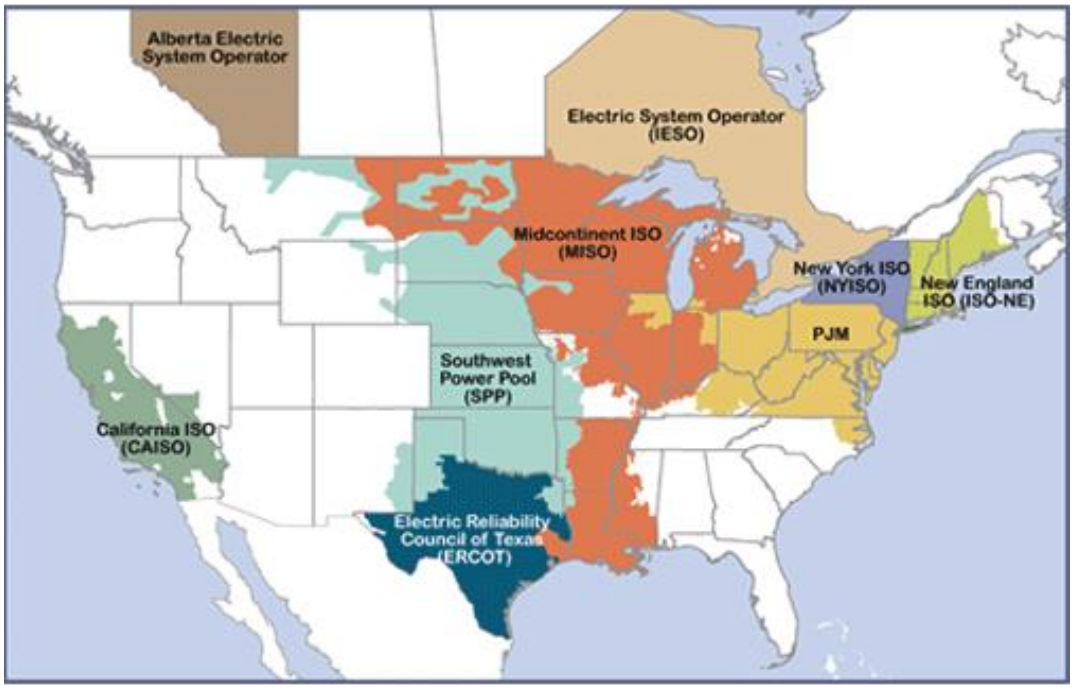


Figure 8. List of potentially relevant jurisdictions that have RTOs/ISOs in North America

ISOs	Year of establishment	Single-jurisdiction ISO?
ERCOT	1996	Y
PJM	1996	N
ISO-NE	1997	N
CAISO	1998	Y
IESO	1998	Y
NYISO	1999	Y
MISO	2001	N
AESO	2003	Y
SPP	2004	N

3.4 Distribution-focused regulatory model

Currently, utilities own and operate the distribution grid. Although there are third-party entities such as solar installers, the technologies must still be connected to the utility grid. However, with the rapid growth of rooftop solar and the advancement of grid technologies, some markets have started to consider alternative business models for the distribution grid. A good example of a distribution-focused regulatory model is New York's Reforming the Energy Vision ("REV"). Like Hawaii's State goal, New York targets increasing the use of clean energy and customer participation in the electricity sector. Its REV initiative is fundamentally shifting the role of the utility from an entity that develops and maintains transmission and distribution assets (utilities

in New York are generally not allowed to own generation assets) to an entity that enables the localized management of electricity supply and demand.

There are two potential models under a distribution-focused regulatory model. The first model is where the distribution system is still owned and operated by the incumbent utilities. This model is more like New York's REV where the distribution utility becomes the Distributed System Platform Provider ("DSPP"). The DSPP's new role, as envisioned by the New York regulator, would be responsible for "planning and designing its distribution system to be able to integrate DER as a primary means of meeting system needs."[41] Under REV, to be able to do this the DSPP is required to "*use localized, automated systems to balance production and load in real time while integrating a variety of distributed energy resources ("DERs"), such as intermittent generation resources and energy storage technologies*."[42] Moreover, the DSPP is required to "*take steps to ensure that distribution systems continue to be modernized through the use of 'smart grid' technologies*" and "*coordinate its planning functions with the implementation by customers of customer-sited DER*."[43] However, this approach requires corresponding incentives in place to ensure that the utilities act in a way that supports the desired outcomes, i.e., allowing third-party access to the grid, making data available, etc.

The second model is where the distribution system is still owned by the utilities but operated by an outside entity. This external entity, which is called the independent distribution system operator ("independent DSO" or "IDSO"), would be under the purview of the PUC and operate and plan for the distribution system. The IDSO is expected to include the day-to-day operations of the grid and be responsible for planning for upgrades of the system. On the other hand, the utilities would maintain and invest for the distribution assets. The utilities would also participate in the planning and operational process of the IDSO. This is the same relationship that an ISO has with the transmission grid.

3.4.1 Oversight under a distribution-focused model

If utilities in the state shift to a DSPP role or have an independent DSO eventually, there would be a change in the current ownership structure of the electric value chain and the ratemaking process. Under the distribution-focused model, diversity of ownership structures for generation is presumed and no one ownership structure for generation need dominate. The transmission and distribution assets would still be owned and operated by incumbent utilities under the DSSP model. The DSSP would provide a distribution marketplace and coordinate with customer-sited DERs. Under the DSPP model, the PUC would also need to ensure fair competition in the distribution marketplace in addition to its current responsibilities.

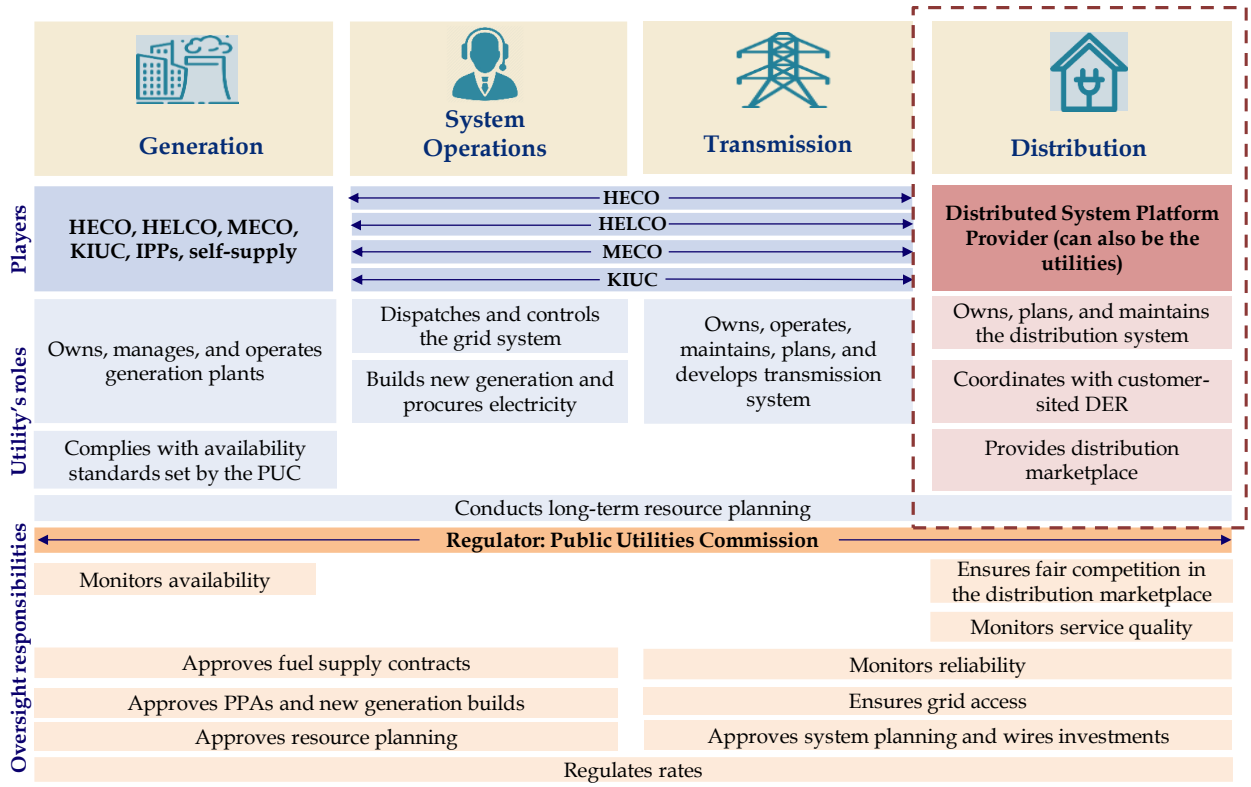
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[41] NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*. Order Instituting Proceeding (issued and effective April 25, 2014). Page 12.

[42] Ibid. Page 13.

[43] Ibid. Page 14 - 15.

Figure 9. Graphical depiction of the value chain under a DSSP model

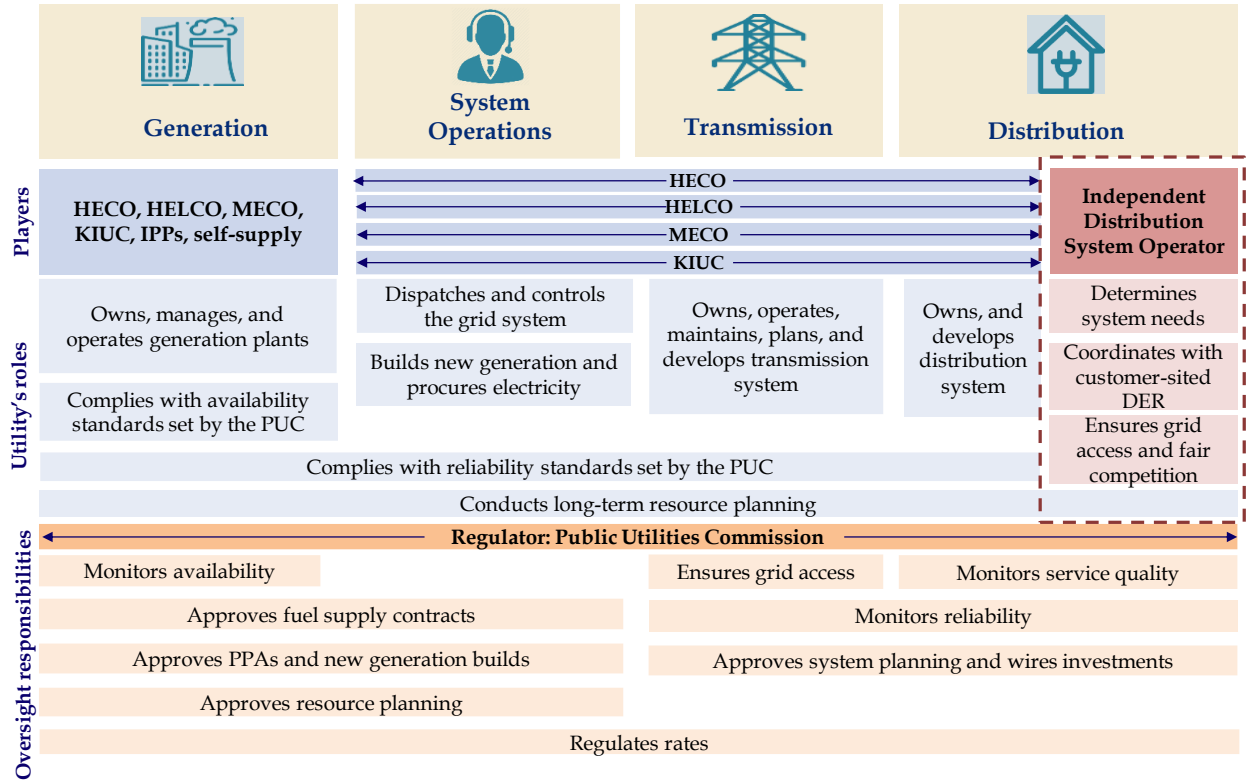


The ratemaking under a distribution-focused model would also change under the DSPP and DSO models. The COS approach would still be used in combination with market-based platform earnings and Outcomes-based earning opportunities, similar to what the New York's REV is proposing.[44] Under REV, utilities will have four ways of achieving revenues, namely, 1) traditional COS earnings; 2) earnings tied to achievement of alternatives that reduce utility capital spending and provide definitive consumer benefit; 3) profits from market-facing platform activities; and 4) transitional Outcomes-based performance measures.[45] Hawaii may consider some of these revenue mechanisms if it opts to do the DSPP model. These different earning opportunities will be discussed in detail in Task 2.2.3 (Financial Feasibility).

[44] NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting A Ratemaking and Utility Revenue Model Policy Framework (issued and effective May 19, 2016) (Track Two Order). Page 2.

[45] Ibid. Page 2.

Figure 10. Graphical representation of the value chain under a DSO model



3.4.2 Jurisdictions that are moving toward a distribution-focused regulatory model

Currently, there is no jurisdiction that has a full-blown distribution-focused regulatory model. However, according to the Lawrence Berkley National Lab, there are generally three stages on the DER adoption, namely: (i) grid modernization, (ii) DER integration, and (iii) distributed markets as shown in Figure 11.[46] Each stage is distinguished by the level of DER adoption in the system, and the technology in place to support DER integration:

- Stage 1 – DER adoption is reasonably low and can be accommodated by the existing technology levels in the grid. This stage represents the state of most existing distribution systems in the US.

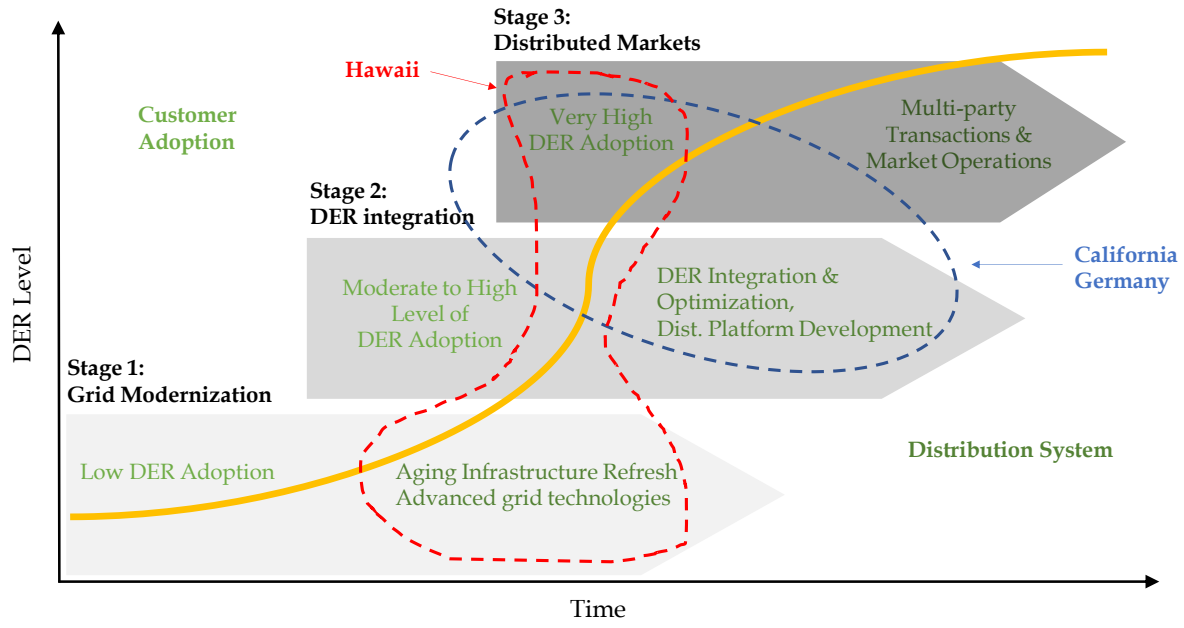
[46] DeMartini & Kristov. *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation & Oversight.* Lawrence Berkeley National Lab. October 2015.

- Stage 2 – DER adoption levels increase such that they are at the threshold level[47] that will require enhanced functional capabilities to ensure reliable system operation.

- Stage 3 – a combination of very high DER adoption, enabling system technology investment and policy decisions allow for the creation of distribution-level energy markets and multi-sided transactions.

As illustrated in Figure 11, DER adoption is uneven across multiple service territories and depending on the scale and nature of the adoption, would affect each system differently. However, at a conceptual level, it is possible to define a progression of levels of adoption, Figure 11 illustrates this adoption process as developed by DeMartini and Kristov in their report for Lawrence Berkeley National Lab's "Future Electricity Regulation" series.[48,49]

Figure 11. DER adoption curves



Sources: LEI analysis and DeMartini & Kristov. *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation & Oversight.* Lawrence Berkeley National Lab. October 2015.

[47] The authors note that empirical evidence from jurisdictions at this level suggests that this level appears when DER adoption reaches beyond about 5 percent of distribution grid peak loading system-wide. (Source: DeMartini & Kristov. 2015).

[48] DeMartini & Kristov. *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation & Oversight.* Lawrence Berkeley National Lab. October 2015.

[49] National Association of Regulatory Utility Commissioners. *NARUC Manual on Distributed Energy Resources Rate Design and Compensation*. November 2016.

Considering jurisdiction policies and DER penetration levels, the Project Team has identified where a few sample jurisdictions lie on the curve. Ontario and Vermont represent the same level of DER development, i.e., moderate to high level of DER adoption, spurred on by generous feed-in-tariffs and coupled with grid infrastructure not keeping pace with the investment.

New York represents the archetype of Stage 2, where a moderate level of DER adoption is also coupled with DER integration. The latter is driven by policy goals and implementation plans from the State government.

Both California and Germany are at varying levels of high DER adoption, spurred by generous feed-in-tariffs. By way of grid integration and optimization, both jurisdictions are driving increasing DER optimization through policy, such as in the case of California with its DER Action Plan. The Action Plan is intended to align DER policies into broad categories, targeting rates, distributed generation ("DG") infrastructure, and market integration.

Hawaii's high DER adoption levels and State policy promotion alongside lagging infrastructure investment levels place it in Stage 2 like New York. The HECO Companies' Grid Modernization Strategy may improve infrastructure such that it could begin the transition towards the third stage, thereby moving closer to or become similar to California.[50]

3.5 Performance-based regulation model

To design an optimal PBR framework, it is first necessary to define performance. In the past, the performance and roles expected from electric utilities, including those in Hawaii, focused on providing adequate and reliable energy supply, maintaining service quality, and complying with technical standards set by the regulator.

However, the energy industry is changing. For instance, the future requires that the energy sector is developed in a way that the electricity system would be able to accommodate more smaller renewable plants and DERs. Particularly, there is an increasing availability of customer-sited and distributed generation in Hawaii. Moreover, the State is pursuing the shift from fossil fuel-based to renewable energy generation.

The current COS regulation may no longer provide the incentives that would encourage the utilities to meet the challenges of renewable and distributed energy future. With these transformations, the performance expected from electric utilities would also need to change. In fact, the performance and role expected of the utilities have been expanded to cover other aspects of the business.[51] Through the *Goals and Outcomes for Performance-Based Regulation in Hawaii:*

[50] It is worth noting that while California is ahead in terms of infrastructure and regulations governing DERs, Hawaii has significantly higher level of DER adoption. The impact is further magnified in Hawaii since it is a much smaller system and each island has its own grid that is not interconnected with other islands. This makes it more important for Hawaii to ensure its grid infrastructure and regulations on DERs keep pace with adoption levels.

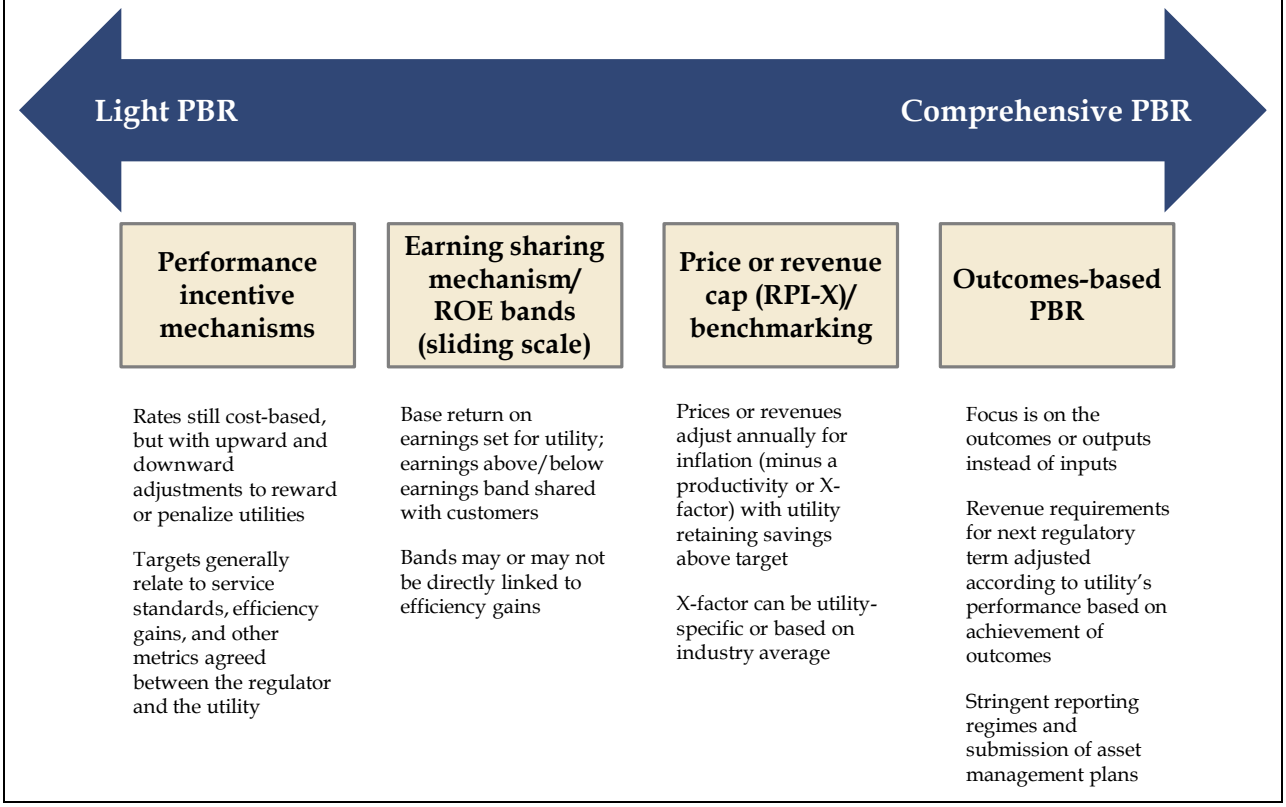
[51] For example, according to a 2017 report on electric utilities performance benchmarking, 257 Key Performance Indicators could be considered, which are clustered in five main categories, namely 1) customers, 2)

Concept Paper to Support Docket Activities under Docket 2018-0088, the PUC has identified potential areas where the HECO Companies' performance will be measured under PBR. These include enhancing customer experience, improving utility performance, and advancing societal outcomes.[52]

3.5.1 PBR as a tool to strengthen utility performance

PBR, compared with traditional COS, can induce desirable changes to utility behavior. PBR can include a variety of mechanisms that could be used in multiple ways and different combinations. PBR is best conceptualized as a continuum, ranging from "light" to "comprehensive" mechanisms, rather than a single type of regulatory regime.

Figure 12. Continuum on PBR regulation from "light" to "comprehensive" key mechanisms



Light PBR includes mechanisms—such as PIMs and ESMs—where payments to the utilities are adjusted based on their level of performance. The "medium" form of PBR mechanism includes the rate cap where either the price or the revenue is capped for the regulatory period. This helps promote efficiency as the mechanism tends to change the link between a utility's rates and its

operations, 3) environment, 4) human capital, and 5) corporate governance. It should be noted that these are examples, and that any tractable regime would have considerably fewer metrics.

[52] Hawaii PUC. *Goals and Outcomes for Performance-Based Regulation in Hawaii*. July 10, 2018. Page 2.

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costs and improves efficiency. At the end of the continuum is Outcomes-based PBR, which is the new generation PBR, where the focus is on the outcomes rather than the inputs to the revenue requirements. Each of these mechanisms will be discussed in detail in the following subsections.

The "right" form of PBR depends on the needs and values of the particular jurisdiction—each may be appropriate depending on the circumstances. Generally, the choice of light versus comprehensive PBR regime is determined by the risk appetite of the utility and the regulator, the range of incentives that the regulator is willing to approve, and the demands of and feedback from interveners. The "light" and "medium" forms of PBR can be considered as "stepping stones" towards the comprehensive PBR mechanism.

Aside from these key PBR mechanisms, there are also other components such as the length of the multi-year rate plan, productivity factor, treatment of unforeseen events or exogenous factors, off-ramp option, and flow-through factors. These will be discussed in Section 3.5.1.5.

3.5.1.1 Performance incentive mechanisms

With PIMs, payments to utilities are adjusted upwards or downwards based on the utilities' level of performance. PIMs involve metrics, targets, and incentives used to examine, evaluate, and enhance a utility's performance over time by providing information on industry trends and opportunities.

PIMs must support the utilities' strategic goals and be achievable, realistic, and measurable. For instance, if one of the utility's goals is "to become a trusted community and business partner delivering valued energy services,"[53] then its PIMs should include service performance and community regard indices. PIMs should be attainable, and utilities and the regulator should cooperate to design challenging, yet realistic standards. Moreover, PIMs must also be consistent with customer needs or expectations and what they are paying for.

Utilities use different PIMs for different sectors of the value chain. For instance, performance is typically measured in terms of efficiency and availability in generation while frequency and duration of outages and customer service metrics are used in the wires sector. Aside from balancing cost efficiencies and reliability, other areas for performance measurement in the wires sector include metering, billing and collection, customer service, and employee safety.

PIM targets are set either by examining historical performance, or focusing on desired outcomes (e.g., comparing it with counterparts'), or through technical or statistical methods. Past performance should provide insights to what the utility can achieve. Another approach is by benchmarking with peer groups. This would help identify areas where opportunities for improvement exist. With a large-sized sample, overall industry patterns reveal trends in performance.

Setting the potential rewards and/or penalties is a balancing act. Rewards and penalties should be significant enough to incentivize the utilities to perform better. They should also be reflective

[53] Energex. *Statement of Corporate Intent*. Energex website. Energex is an Australian electric power distribution company owned by the Government of Queensland.

of the actual cost to remedy performance shortfall. Generally, rewards and/or penalties under PIMs are based on deviations set in percentage terms or standard deviations from performance targets. Lastly, in determining and setting PIM targets, there should be a balance between the utility's financial viability and customer expectations and willingness to pay. Caps on the amount of exposure to performance fines act as an insurance mechanism to ensure the utility's economic sustainability. Furthermore, rate increases may be required to increase performance significantly and/or maintain exceptional performance targets.

Numerous markets have implemented PIMs. Most of these PIMs are focused on reliability and service quality metrics. Figure 13 shows an example of distribution performance incentives that are both financial and non-financial.

Figure 13. Sample jurisdictions that have PIMs

	Consolidated Edison of New York	Central Maine Power	New Brunswick Power	San Diego Gas and Electric	Ontario
Term of Tariff Plan	2010-2013	2008 – 2014	2013 - present	1999-2002	2009-2011
Rewards, Penalties or Both	Penalties Only	Penalties only	Penalties Only	Both Rewards and Penalties	Nonfinancial measures
Explicit Formula (Yes/no)	Yes	Yes	No	Yes	No
Reliability Metrics	SAIFI, SAIDI, other reliability investment metrics	CAIDI, SAIFI	All mandatory NERC Standards	CAIDI, SAIFI, MAIFI	SAIFI, SAIDI, CAIDI
Service Quality Metrics	Customer complaints, customer satisfaction, call answer rates	Complaint ratio, calls answered (%), call center quality, meters read, new connections	No explicit service quality standards tracked and subject to fines from the Energy and Utilities Board	Customer satisfaction, call center response, all injury frequency rate	New connections, underground cable locations, telephone accessibility, appointments made, emergency and written responses
Max Penalty	$152 Million	$5 million	N/A	$14.5 million	N/A

Notes:
AIFI - Average Interruption Frequency Index calculates the average number of momentary interruptions that a customer would experience in a given period.
CAIDI - Customer Average Interruption Duration Index ("CAIDI") measures the total duration of an interruption for the average customer and can be calculated as a ratio of SAIDI and SAIFI, provided they are calculated over the same period.
SAIDI - System Average Interruption Duration Index ("SAIDI") measures the total duration of an interruption for the average customer in a given period, typically in hours or minutes per year.
SAIFI - System Average Interruption Frequency Index ("SAIFI") measures the average number of times that a system customer experiences an outage in a given period and is usually calculated on an annual basis

Sources: California Public Utilities Commission ("CPUC"), Maine Public Utilities Commission ("MPUC"), New Brunswick Energy and Utilities Board, New York State Public Service Commission ("NY PSC"), and Ontario Energy Board ("OEB").

HECO Companies' PIMs

HECO Companies report performance metrics in eight categories to the PUC, including:

- service reliability,
- power supply and generation,
- renewable energy,
- customer service,
- financial,
- safety,
- rates and revenues, and
- emerging technologies.

The metrics under most of these categories are tracking-only metrics, without associated rewards or penalties.

Among these performance metrics, only System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), and call center performance are PIMs that are included in ratemaking. The PUC recently also approved PIMs related to HECO Companies' achievement of cost savings in renewable generation procurement and implementation of demand response ("DR") portfolio.

Source: Order 35411

3.5.1.2 Earnings sharing mechanisms

An earnings sharing mechanism is another mechanism under PBR. ESMs are designed so that the extraordinary earnings (or losses) are shared among the company and its customers rather than retained (or absorbed) entirely by the company if formulae-driven price adjustments result in a significant divergence between prices and costs.[54]

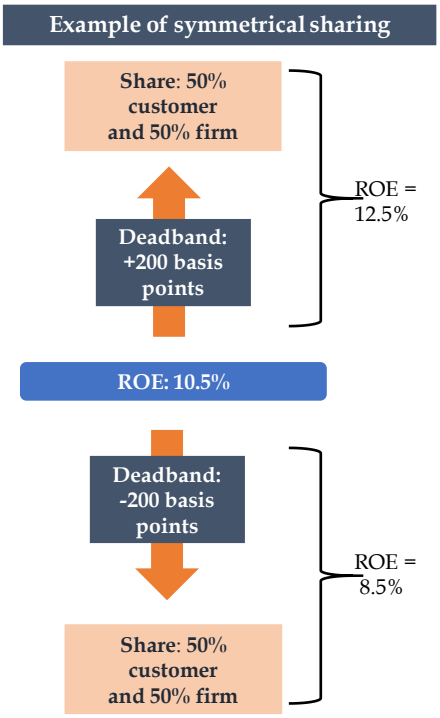
Generally, ESMs involve three elements, namely, (i) a target return on equity ROE, (ii) a deadband around the ROE in which no sharing takes place, and (iii) sharing of gains or losses, which are outside the deadband. The ROE is the regulator-approved return for the utility. The deadbands allow customers to participate in gains without requiring extensive regulator involvement. The sharing percentages are the level of sharing between the utility and customers.

Deadbands and sharing percentages can either be symmetrical or asymmetrical. Customers share both upside and downside risks equally under the symmetrical system while customers or the

[54] Such mechanisms serve the same basic purpose—ensuring prices do not get too distorted or deviate too much from actual costs—as in the case of clawbacks within a traditional COS system. In the context of indexation formulae, an alternative and a more drastic one to an ESM is an exit ramp, which triggers an automatic end to the current formulae application period (and thereby initiates a COS rate review) if prices deviate too much from costs.

regulated utility are taking on a disproportionate portion of the risk under an asymmetrical system. Figure 14 shows an example of an ESM with a symmetrical deadband and sharing percentages.

Figure 14. Example of a symmetrical sharing



However, there are also some identified drawbacks to ESM. First, an ESM can complicate the administration of a PBR system.[55] Second, ESM reduces the efficiency incentives created by shifting to PBR if attached to a productivity factor target. Some argue that a successful PBR implementation does not require an ESM. Nevertheless, many believe that by allowing customers to share in benefits--which arguably would not occur in the absence of incentives--the overall political acceptability of a PBR plan may also be increased. For instance, true-ups under a symmetrical ESM mechanism can neutralize the perceived impact of rate increases in the re-basing or review stage.

Although ESMs are not a feature of all PBR regimes, they are commonly used across the US and are unusual outside North America. A sample of provisions of these ESMs across the US is shown in Figure 15.

[55] For instance, during its first generation PBR, ENMAX was concerned with the information and retail requested by the intervenors and the Commission in the process of determining the earnings sharing amount.

HECO Companies' ESM

In the case of the HECO Companies, the ESM is asymmetrical where only above threshold earnings (i.e., where utility earnings are greater than the authorized return on equity ("ROE")) are shared with the customers. This means that where there are no above threshold earnings (i.e., earnings are at or below the authorized ROE), any lower than expected earnings will be fully absorbed by the utility's shareholders and not by its ratepayers.

In other words, if the utilities' ROE is at or below the authorized ROE, any earnings will be retained entirely by shareholders. If the actual ROE is more than 100 basis points or 1% over the authorized ROE, customers will be credited a 25% share. If the actual ROE is more than 200 basis points or 2% over the authorized ROE, the customers will get a 50% share. If the ROE exceeds 300 basis points or 3% of the authorized ROE, the customers get a 90% share.

Source: Order No. 35411, at 43

Figure 15. Selected jurisdictions and their ESM provisions

Company Name	US State	Term	Sharing Mechanism
Central Hudson Gas & Electric	New York	Jul 1, 2010-Jun 30, 2013	Actual regulatory earnings in excess of 10.50% and up to 11.00% will be shared equally between ratepayers and shareholders. Actual regulatory earnings in excess of 11.00% and up to 11.50% will be shared 80/20 (ratepayer/shareholder). Actual regulatory earnings in excess of 11.50% will be shared 90:10 (ratepayer/shareholder).
Florida Power & Light Co.	Florida	2006-2009	FPL's shareholders will receive a 1/3 share and FPL's retail customers will receive a 2/3 share.
Narragansett Electric	Rhode Island	Feb 1, 2013-Jan 31, 2014	Earnings between 9.5% and 10.5% are shared 50:50 between the utility and its ratepayers, while earnings in excess of 10.5% return are shared 25:75.
NSTAR	Massachusetts	2007-2013	ESM dead band is 8.5%-12.5%. If ROE is above/below the dead band, the earnings are shared 50:50.
San Diego Gas & Electric Co.	California	2005-2007	The sharing mechanism contains a symmetrical 50 basis points "inner dead band" and six sharing bands between 50 and 300 basis points above or below the authorized ROR. Shareholders receive 25 percent of the earnings above or below the authorized ROR in the first band, increasing by 10 percent in each subsequent band.
United Illuminating Co.	Connecticut	Jan 11, 2006-Dec 31, 2009	ESM is based on sharing of earnings above target ROE (9.6%) where 50% is retained by the shareholder, 25% goes to customers through bill credits and the remaining 25% goes to reduce the customer's balance of standard costs.

Sources: State of New York Public Service Commission, Florida Public Service Commission, Rhode Island Public Utilities Commission, Massachusetts Department of Public Utilities, California Public Utilities Commission, State of Connecticut Department of Public Utility Control

3.5.1.3 Rate caps

Unlike a rate freeze, rates under rate caps could change during the regulatory term, based on the approved formula. More specifically, utility's rates are adjusted annually through an indexing formula that tracks the inflation rate; less an offset to reflect the improvements in productivity that the utility could expect to achieve during the regulatory period. Under a rate cap, the utility is required to perform annual productivity improvements. Furthermore, with a rate cap, a

utility's revenues are allowed to diverge from its costs during the regulatory period. The decoupling of costs and revenues incentivizes the utility to increase productivity and decrease costs.

Price caps and revenue caps are examples of rate caps. The critical difference between price and revenue cap regimes is related to what the PBR formula applies to – rates in the case of price cap regimes, and revenue requirements in the case of revenue cap regimes.

Under a **price cap**, which is also called price indexing or rate indexing, the regulator approves a formula that determines how fast rates can increase. The regulator sets an ***initial price,*** and the rates are adjusted for each year taking changes in inflation and productivity into account. A price cap provides incentives for cost efficiency and increase of sales. These incentives arise because the tariff is fixed for the regulatory period and would not vary with changes in electricity sales within the regulatory period. Another advantage of a price cap is that it provides greater rate predictability for customers.

A price cap regime is best suited for utilities in an environment with stable or increasing demand as it provides incentives for them to operate cost-effectively while meeting the growing demand. Under a price cap, the utilities' revenues could grow with new customers and growth in demand from existing ones. The additional revenue contributes funding for the increased capital and operating costs of serving new customers and additional load. However, utilities operating under a price cap regime are also exposed to revenue risk associated with actual electricity sales varying from forecasts of electricity sales used to set the rates.

On the other hand, the **revenue cap** regulates the maximum allowable revenue that a utility can earn. Under a revenue cap, the ***revenue requirement*** in a given year is established according to the previous year's revenue requirement and adjusted based on a predetermined formula, which considers changes in inflation and productivity.

Under a revenue cap, there is no incentive for utilities to maximize sales, but there is still an incentive to minimize overall costs, making it arguably more compatible with utilities that are facing substantial demand response programs or energy efficiency reductions in consumer demand. Revenue cap regimes provide more pricing flexibility and are preferable when costs do not vary significantly with sales volumes.

The advantages and disadvantages and where these two rate caps are suitable will be discussed in Appendix A.

3.5.1.4 Outcomes-based PBR

At the comprehensive end of the PBR is Outcomes-based PBR. Outcomes-based PBR focuses on the outputs or outcomes of the PBR plan, rather than activities, which is generally the emphasis of the traditional rate filing.

The utilities in an Outcomes-based PBR are expected to achieve the outputs that are set during the PBR filing (or before the implementation of PBR). These outcomes could be grouped into different categories such as reliability and availability, operational effectiveness, safety, public

policy responsiveness, customer satisfaction, financial performance, and environment, to name a few.

A good example of a jurisdiction under the Outcomes-based PBR is the UK's RIIO model, which stands for **R**evenue set to deliver strong **I**ncentives, **I**nnovation, and **O**utputs. Under the RIIO model, the transmission and distribution utilities in the UK are encouraged to "*play a full role in the delivery of a sustainable energy sector*[56] *and deliver value for money network services for existing and future consumers.*"[57]

This model requires utilities to submit robust business plans that demonstrate that they are proposing the best option in terms of meeting the goals of the RIIO model.[58] The business plans include data such as the utilities' forecasts for network replacement, and capacity additions, to name a few.

A more detailed discussion about the RIIO model will be discussed in Task 2.2.2. (Case Studies).

3.5.1.5 Other potential PBR parameters

Other jurisdictions use other PBR components alongside the mechanisms mentioned above. These other parameters – which add to the PBR formula -- include treatment of (certain) capital expenditures and unforeseen events, length of the regulatory period, and triggers for an "exit" or "off-ramp." Along with the mechanisms discussed above, the PBR parameters are shown in

[56] Ofgem defines sustainable energy sector as "an energy sector that meets the broad needs of existing and future consumers. This includes delivery of low carbon energy and other environmental objectives, delivery of secure, safe supplies and delivery of value for money including meeting the needs of vulnerable consumers," from the Handbook for Implementing the RIIO Model.

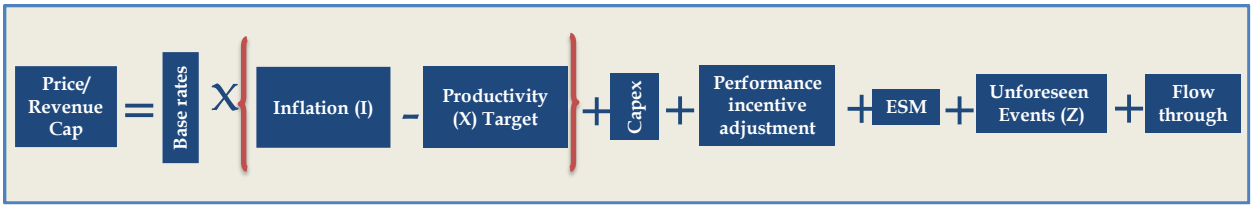
[57] Ofgem. *Handbook for Implementing the RIIO Model*. October 4, 2010. Page 2.

[58] Ofgem. *Handbook for Implementing the RIIO Model*. October 4, 2010. Page 48.

Figure 16.

Determining the individual PBR components requires careful consideration and these components need to be viewed holistically. Therefore, in determining the appropriate parameters and their combinations, the choice of one parameter influence the others. For example, the productivity factor is not independent of the inflation factor because an inflation index using macroeconomic Outcomes-based measures takes some level of productivity gains into account. Also, utilities would consider the regulatory term of PBR depending on how they perceive their abilities to perform under a PBR regime. For example, a well-performing utility may assume that a longer regulatory term under PBR would provide a more extended period for it to reap the "rewards" of cost gains, while utilities that are not confident about achieving their productivity target may view a shorter period as a lower risk proposition.

Figure 16. Key components to consider for a PBR formula



Components	Purpose
Going-in rates	Starting point of the PBR regulatory term. Rates usually determined through a COS filing (or rebasing). The PBR annual adjustment (I – X) is subsequently applied to those rates during the regulatory period
Regulatory period	Scheduled time lag between two major reviews of the underlying components of the ratemaking regime
(I) - Inflation/ escalation factor	Annual adjustment to the utility's revenue or rates reflecting the level of inflation, usually reflecting the actual inflation rate in the previous year
(X) - Productivity factor / stretch factor	Annual adjustment to revenue or rates reflecting expected changes in terms of productivity. May be based on the utility's historical performance or on external benchmark. May include a firm-specific target, or stretch factor
(K) - Capital expenditure or (G) Growth factor	Annual adjustment to the utility's revenue or rates reflecting forecasted capital expenditure (capex) needs or ex post approval of capex spending in the previous year
(Q) - Performance standards factor/ PIM	Contingent adjustment to revenue or rates for rewards/penalties linked to the achievement or failure to reach specified performance targets, usually in terms of service quality as well as reliability and quality of supply
(ESM) - Earnings sharing mechanism	Mechanism through which a specified portion of a utility's profits in excess of/below the approved return on equity/forecasted level of expenditures is returned to customers
(Z) - Unforeseen events factor	Contingent adjustment to revenue or rates in order to recover extraordinary costs that are outside of the company's ability to control or predict
Regulatory review / Off-Ramp option	Mechanism allowing to trigger, under specified circumstances, a review of the ratemaking regime in place before the end of the regulatory period. The process may lead to the overhaul or the termination of the regime
(F) - Flow-through factor	Contingent adjustment to revenue or rates reflecting certain cost event are automatically passed through to customers as they arise, without having to be approved by the regulator

3.5.2 Jurisdictions under PBR

PBR regimes exist in multiple jurisdictions throughout the world as shown in

Figure 17. In North America, the markets that have used or is currently using PBR rate caps include British Columbia, Alberta, Ontario, Oregon, California, New York, Maine, and Massachusetts. PBR mechanisms used by markets in North America include PIMs, ESM, and rate caps. It is only Ontario that is currently implementing an Outcomes-based PBR, which they call customized PBR. Countries outside of North America, such as the UK and Australia, utilize a more comprehensive combination of PBR mechanisms. Some countries in Asia, such as Malaysia and the Philippines, are also implementing comprehensive PBR mechanisms. A list of potentially relevant jurisdictions that have PBRs is shown in the map below.

Figure 17. Jurisdictions that have used, or are currently using or plan to move to PBR

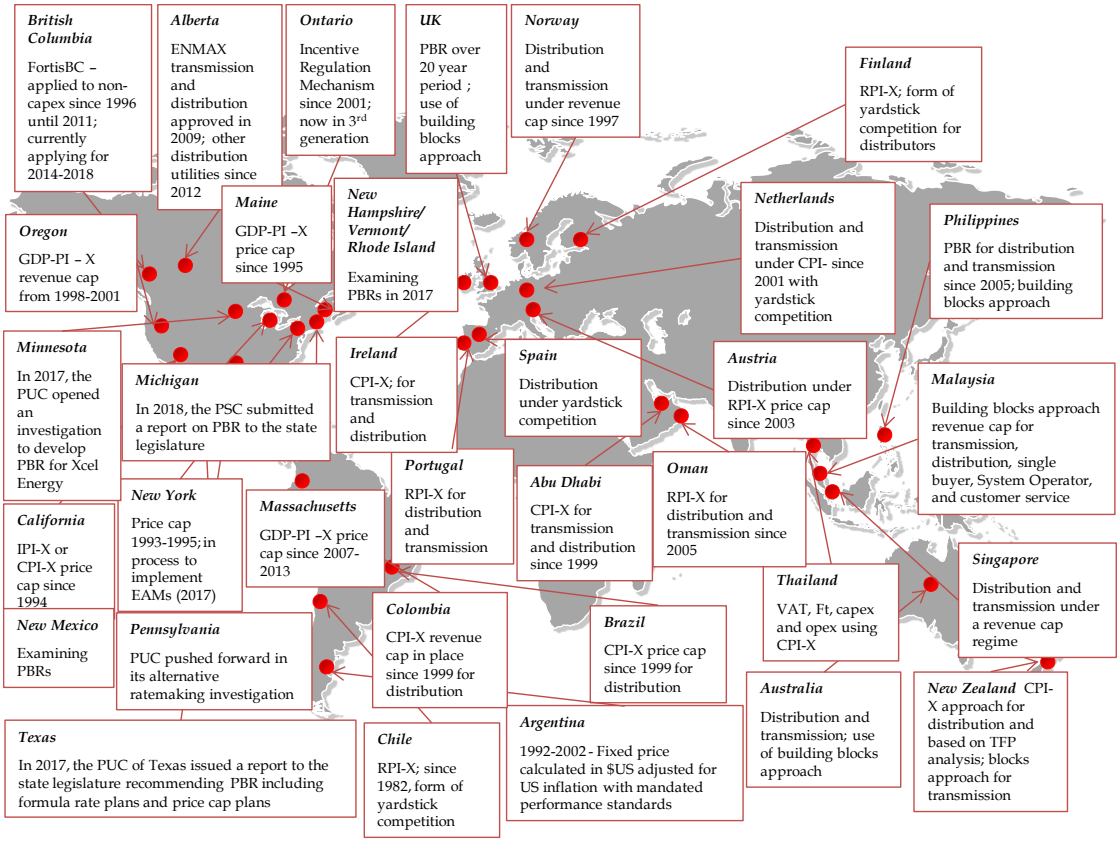


Figure 18. Sample jurisdictions that have used, are currently using, or plan to move to PBR

International	
Jurisdiction	**Type of PBR**
Alberta	Price cap (distribution), revenue cap (transmission)
Australia	Revenue cap (transmission), price cap (most distribution)
British Columbia	Price cap
Malaysia	Price cap (customer services), revenue cap (transmission, system operator, single buyer - operational), actual costs (single buyer)
Ontario	Price cap
Philippines	Price cap (maximum average price)
UK	Price cap, RIIO
States in the US	
States	**Type of PBR**
California	IPI-X or CPI-X price cap (1994 - 2000s), PIMs
Illinois	NextGrid initiative, PIMs
Maine	GDP-PI - X (1995 - 2013)
Massachusetts	I-X (Total Factor Productivity method)
Minnesota	Performance metrics for Xcel Energy
New York	REV, Earnings Adjustment Mechanisms
Ohio	PowerForward initiative
Oregon	GDP-PI - X revenue cap (1998-2001)
Rhode Island	Power sector transformation initiative

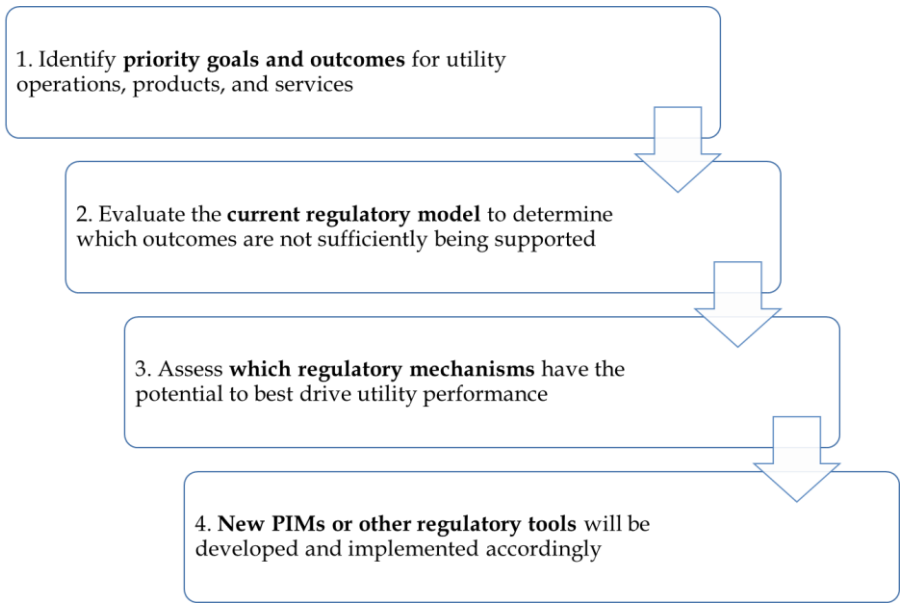
Note: this is not an exhaustive list; Illinois, Minnesota, Ohio, and Rhode Island are studying PBR as part of a broader power sector transformation initiative
Source: LEI study; Hawaii PUC. Order 35411 Instituting a Proceeding to Investigate PBR. Docket 2018-0088.

3.5.3 PBR in Hawaii

The Governor of Hawaii signed Senate Bill 2939 (now known as the Ratepayer Protection Act) into law on April 24, 2018. The law directs PUC to have performance incentives and penalty mechanisms that promote affordability of rates, electric reliability, customer choice and satisfaction, data transparency, "*rapid integration" of renewables, including third-party home solar and storage systems, and "timely execution of competitive procurement ... and other business processes.*"[59]

The PUC also opened docket 2018-0088 to investigate performance-based regulation and get inputs from stakeholders regarding the current regulatory model, specific areas of utility performance that should be improved, and the PBR frameworks that will be developed to increase the alignment between the utilities' interests and those of the customers. In contrast to the performance incentive mechanisms where the purpose is to *"provide financial rewards and/or penalties for utility performance according to specific metrics, without necessarily requiring a substantial change to other ratemaking procedures,"* the PBR framework "*constitute[s] a wholesale change in the regulatory procedures and cost control incentives associated with the traditional ratemaking process by, among other things, allowing utilities to profit from realized cost efficiencies and to establish financial rewards or penalties based on utility performance according to specific incentive metrics.*"[60]

Figure 19. Hawaii PUC's conceptual framework to guide the PBR process



Source: Hawaii PUC. *Goals and Outcomes for Performance-Based Regulation in Hawaii*. July 10, 2018. Page 2.

[59] SB2939. Ratepayer Protection Act.

[60] PUC. *Order No. 35411 Instituting a Proceeding to Investigate Performance-Based Regulation*. Docket No. 2018-0088. April 18, 2018. Page 37.

The PBR would only apply to the HECO Companies because "*… as a member-owned, non-profit electric utility cooperative … KIUC is unlikely to present the same potential risks to KIUC's customers as compared to those present for customers of for-profit, investor-owned utilities like the HECO Companies*."[61]

The current regulatory framework also has some components associated with PBR. These include a fixed three-year cycle for general rate cases, the decoupling mechanism, an ESM, an interim-period revenue adjustment mechanism which includes a revenue cap, and PIMs. A more detailed discussion of the proposed PBR for Hawaii will be covered in Task 2.1.2. (Existing Regulatory Model in Hawaii).

On July 10, 2018, the Hawaii PUC released a concept paper, *Goals and Outcomes for Performance-Based Regulation in Hawaii*, to support docket activities in the PBR Docket. To guide the PBR process, the PUC has adopted a conceptual framework where the PBR process would include identifying priorities and goals, assessing the current regulatory model and determining which regulatory mechanisms would drive utility performance. The process is summarized in **Error! R eference source not found.**.[62]

3.5.4 Potential PBR options for Hawaii

As discussed earlier, there are different mechanisms under PBR. This Study will analyze the costs and benefits of each regulatory model, so concrete PBR options need to be determined and evaluated. The Project Team proposes three PBR options for Hawaii, taking off from the goals of the Hawaii Ratepayer Protection Act, which "*directly tie an electric utility revenues to that utility's achievement on performance metrics and break the direct link between allowed revenues and investment levels,*"[63] and PUC's aspirations of "*greater cost control and reduced rate volatility, efficient investment and allocation of resources, fair distribution of risks and fulfillment of state policy goals,*"[64]. These three are Light PBR, Conventional PBR, and Outcomes-based PBR, which are discussed in detail below. The key components of each proposed PBR option are summarized in Figure 20.

The PBR regime in the succeeding regulatory periods would evolve and would be tailored to the specific environment and circumstances of the utilities. One of the lessons learned from other jurisdictions that have successfully implemented PBR is the need to adapt to changes when necessary. For instance, in the UK, the Office of Gas and Electricity Markets ("Ofgem") has routinely made modifications to the PBR regulations after each regulatory period to improve a particular mechanism that did not work as anticipated or to adapt to changes in the environment.

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[61] Ibid. Page 9.

[62] Hawaii PUC. *Goals and Outcomes for Performance-Based Regulation in Hawaii*. July 10, 2018.

[63] HRS §269.

[64] PUC. *Order No. 35411 Instituting a Proceeding to Investigate Performance-Based Regulation*. Docket No. 2018-0088. April 18, 2018. Page 52.

Figure 20. Key components of each proposed PBR option

	Status quo	Light PBR	Conventional PBR	Outcomes-Based PBR
Regulatory term	3 years	3 years	3 years	5 years
Rate-setting approach	Cost of Service	Cost of service	Revenue cap using indexing formula (e.g., inflation less productivity factor)	Revenue cap using building blocks approach
Performance incentives mechanisms	• Reliability (SAIDI and SAIFI) (penalty only) • Call center performance • Cost savings in renewable generation procurement (rewards and penalties) • Implementation of demand response portfolio (rewards only)	Expand current list to include metrics in the following categories: • Availability • Reliability • Cost control • Service quality • Customer engagement • Competitive procurement • RPS targets	Similar to Light PBR: • Availability • Reliability • Cost control • Service quality • Customer engagement • Competitive procurement • RPS targets	Based on the outcomes to be achieved, the PIM list is more comprehensive than Light and Conventional PBR: • Customer satisfaction • Service quality • Customer engagement • Availability • Reliability • Safety • Cost control • Asset management • Connection of renewable generation • Connection of DERs • RPS target • Demand response implementation • Competitive Procurement • Financial ratios
Earnings sharing mechanism ("ESM")	Asymmetrical ESM where customers will be credited: • 25% of share if the actual ROE is more than 1% of the authorized ROE • 50% of share if the actual ROE is over 2% than the authorized ROE • 90% of share if the actual ROE is over 3% of the authorized ROE	Similar to current ESM where customers share the excess earnings	ESM is symmetrical in terms of sharing percentages and deadbands. Deadbands are larger to reflect risks	Similar to conventional PBR where ESM is symmetrical
Treatment of capital and operating expenditures	Capex included in the rate base; O&M passed through	Similar to current approach	Total expenditure ("totex") approach	Totex approach

3.5.4.1 Option A: Light PBR

For Light PBR, the Project Team plans to build upon the existing regulatory model **and expand the current PIMs** to include other performance metrics, facilitating more effective achievement of the state's energy goals. This means that rates would be determined using the COS approach and there would be penalties and rewards for achieving or missing the targets. The expanded PIMs would work in conjunction with and would not replace all other current performance and customer service standards set by the PUC and any guaranteed minimum service levels standards. The regulatory term would be the same as the current general rate cycle of three (3)

years. Finally, Light PBR would include the current ESM where above threshold earnings would be shared with the customers. Figure 21 lists the major features of Light PBR.

Figure 21. Key features of Light PBR

	Light PBR
Regulatory term	3 years
Rate-setting approach	Cost of service
Performance incentives mechanisms	Expand current list to include metrics in the following categories: • Availability • Reliability • Cost control • Service quality • Customer engagement • Competitive procurement • RPS targets
Earnings sharing mechanism ("ESM")	Similar to current ESM where customers share the excess earnings
Treatment of capital and operating expenditures	Similar to current approach

Regulatory term

As indicated above, the regulatory term under Light PBR would be the same as the **current three-year** general rate cycle.

Cost of service approach

Under Light PBR, the current rate-setting approach (in which the base rates are estimated from the target revenue requirement, which is the annual energy revenue approved by the PUC in the most recent test year general rate) [65] would still be used. This target revenue requirement would be calculated using the COS approach. For the succeeding two years of the regulatory term, the base rates would be adjusted using a per kWh rate adjustment (the "RBA Rate Adjustment"), which would be calculated by dividing a sum which includes the calendar year-end balance in the RBA balance as well as certain adjustments included in the Revenue Adjustment Mechanism ("RAM") and PIM provisions by the Company's forecast of MWh sales over the RBA Rate

[65] It should be noted that the target revenue excludes the following per the HECO Companies Revenue Balancing Account Provision: (i) revenue for fuel and purchased power expenses that are recovered either in the base rates or in a purchased power adjustment clause, (ii) revenue being separately tracked or recovered through any other surcharge or rate tracking mechanism, and (iii) applicable revenue taxes.

Adjustment recovery period.[66] Below is the formula of the rate under Light PBR. The PIMs and ESM will be discussed in the sections below.

$$(\text{PRICE})_{\text{Year2}} = (\text{PRICE})_{\text{Year1}} \text{ +/- PIMs +/-RAM - ESM}$$

PIMs

As mentioned earlier, most of the HECO Companies' performance metrics are tracking-only metrics without associated rewards or penalties. There is only one PIM – call center performance – which has both rewards and penalties. The PIMs with penalties only are focused primarily on reliability (i.e., SAIFI and SAIDI). For PIMs with rewards only, the metrics are related to public policy goals such as renewables (procurement of renewable generation), DR (implementation of DR portfolio), and costs (cost savings). Under Light PBR, the current list of PIMs would be **expanded to include other categories such as** reliability, cost control, service quality, customer engagement, competitive procurement, and RPS achievement.

These additional categories would be in line with the goals of the Hawaii Ratepayer Protection Act, which states that

> *"in developing incentive and penalty mechanisms, the PUC's review of electric utility performance shall consider, but not be limited to, the following: (1) the economic incentives and cost-recovery mechanisms described in section 269-6(d); (2) volatility and affordability of electric rates and customer electric bills; (3) electric service reliability; (4) customer engagement and satisfaction, including customer options for managing electricity costs; (5) access to utility system information, including but not limited to public access to electric system planning data and aggregated customer energy use data and individual access to granular information about an individual customer's own energy use data; (6) rapid integration of renewable energy sources, including quality interconnection of customer-sited resources; and timely execution of competitive procurement, third-party interconnection, and other business processes."*[67]

Figure 22 shows some of the potential metrics under each of these categories.

In addition to expanding the list of the PIMs, Light PBR would also have **symmetrical PIMs** where the utilities' outstanding performance would be rewarded while poor performance would be penalized. As discussed earlier, the performance targets could be set by looking at the utilities' historical performance, benchmarking with comparables, or using appropriate statistical methods. The targets should also be valued by customers, can be objectively measured and independently audited. In setting the targets, the Commission should also consider the utilities'

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[66] *See, e.g.*, Tariff Applicable to Electric Service of Hawaiian Electric Company, Inc., Revenue Balancing Account ("RBA") Provision, *available at* https://www.hawaiianelectric.com/Documents/my_account/rates/hawaiian_electric_rates/heco_rates_rba.pdf .

[67] SB2939. Ratepayer Protection Act.

historical performance, the inherent variability in performance data, and cost impact to achieve targets.

Figure 22. Potential metrics under each performance categories

Performance Categories	Performance measures
Availability	• Generation Availability • Equivalent Forced Outage Factor • Equivalent Forced Outage Factor Demand
Reliability	• SAIFI • SAIDI • No. of times that Power to a Customer is Interrupted
Cost control	• Cost of final delivered energy to Customers By Rate Class for Each Island System • Total Cost per Customer • Total Cost per Km of wires
Service Quality	• Telephone Calls Answered on Time • New Customer Connected on Time
Customer engagement	• No. of Consultations Conducted
Competitive procurement	• Timely conduct of a competitive procurement • Cost savings in renewable generation procurement
RPS targets	• Percentage of renewables relative to total energy • No. of Renewables Connected on Time

Rewards and penalties for PIMs are based on deviations from the performance targets. In theory, any formula which sets out penalties for missing performance targets should result in consequences high enough to deter poor performance and at least exceed the cost savings that the utility derives from not devoting resources into achieving targets. In the same manner, rewards should be significant enough to incentivize good performance, but also reflect consumer willingness to pay. In general, rewards and penalties are at times designed in a linear fashion. This means that the rewards and penalties are symmetrical. They also may be designed exponentially in which more substantial performance deviations from targets are rewarded or penalized disproportionately more than smaller performance deviations.

In implementing the PIMs, the Commission could either set a point estimate target or have an upper bound and a lower bound target for each PIM. In the former approach, the actual performance would be compared to the point estimate target to determine either an incentive or penalty. Meanwhile, if the actual performance is less than the lower bound target (in the latter method), a penalty would be imposed and vice versa. If actual performance lies between the lower and upper bound targets, no penalty or incentive would be levied.

Generally, there is a cap either for each potential fine (or reward) or a utility's maximum total exposure to performance standard rewards or penalties. Since PBR is relatively new in Hawaii, a cap on the annual financial exposure to the HECO Companies is recommended as a soft start. The cap could be increased as the Commission and HECO Companies acquire more experience

with the PBR implementation. In some jurisdictions, the rewards and penalties are applied to the next regulatory period. The total incentives or penalties for each PIM are summed up to derive the total PIM payment at the end of the regulatory term. The total PIM payment would then be amortized, in present value terms, and added to or subtracted from the utility's revenue requirements of the succeeding regulatory period. An illustrative example of this approach is provided in Figure 23. Alternatively, the Commission could use the current approach of reflecting the rewards and penalties in the rates on the following t year.

Figure 23. Example of how to apply the rewards and penalties to the next regulatory period

	Regulatory period 1 (in $ millions) *Rewards or penalties based on performance relative to the target*				Regulatory period 2 (in $ millions) *Rewards or penalties based on performance relative to the target*			
	Year 1	Year 2	Year 3	Total	Year 1	Year 2	Year 3	Total
PIM 1	-	-	$ 2.00	$2.00				
PIM 2	($1.00)	($0.75)	($1.75)	($3.50)				
PIM 3	$5.00	$4.00	-	$9.00				
Total Rewards (Penalties)				$7.50				
Rewards added to the annual revenue requirements					$2.50	$2.50	$2.50	$7.50

Under Light PBR, there would be **active monitoring of performance against set targets**. The utilities would be expected to submit quarterly reports[68] on their performance to the Commission, all of which should also be posted on the utilities' websites.

ESM

The enhanced PIMs would also be coupled with the same **ESM** as the current one where only above threshold earnings are shared with the customers. More specific examples of calculations of customer rebates/credits based on ROE (under the current ESM structure) are shown below:

- If HECO Companies' actual ROE is more than 100 basis points or 1% over the authorized ROE, customers will be credited with a 25% share.
- If the actual ROE is more than 200 basis points or 2% over the allowed ROE, the customers will get a 50% share.
- If the ROE exceeds 300 basis points or 3% of the authorized ROE, the customers get a 90% share.

[68] Currently, HECO Companies are required to submit their PIM data on a quarterly basis.

Light PBR would be easier to implement, given the timeline provided by the legislation (where PBR needs to be applied by January 1, 2020), compared with the other two PBR models discussed below.

However, as discussed earlier, each performance metric requires a reasonable target which relies on available data, either from the HECO Companies or comparable peers. Implementation of each performance metric also requires certain expenditures from utilities, eventually causing an increase in rates. Selecting practical PIMs, precise targets, together with appropriate ESM is critical to the success of this approach.

3.5.4.2 Option B: Conventional PBR

A revenue cap would be used to determine the revenues and rates during the PBR term under the Conventional PBR. The expanded list of PIMs and the reporting requirements would also be the same as in Light PBR. There would also be an ESM; however, the deadband would be larger and the sharing and deadband symmetrical. The total expenditure ("totex") approach would also be utilized under this option.

Figure 24. Key features of Conventional PBR option

	Conventional PBR
Regulatory term	3 years
Rate-setting approach	Revenue cap using indexing formula (e.g., inflation less productivity factor)
Performance incentives mechanisms	Similar to Light PBR: • Availability • Reliability • Cost control • Service quality • Customer engagement • Competitive procurement • RPS targets
Earnings sharing mechanism ("ESM")	ESM is symmetrical in terms of sharing percentages and deadbands. Deadbands are larger to reflect risks.
Treatment of capital and operating expenditures	Total expenditure ("totex") approach

Regulatory term

Conventional PBR would also have a three-year term as in the case of Light PBR.

Revenue cap

Unlike Light PBR, Conventional PBR would have a **rate cap**. As discussed in Section 0, a rate cap can either be a price or revenue cap. One is not necessarily better than the other, but the suitability of the rate cap would depend on how it aligns with the goals and needs of the State. Given the

increasing availability of customer-sited, distributed generation and flat or declining forecasted demand in the State, a revenue cap would be a better option for the State. Indeed, a revenue cap would be more compatible than a price cap for Hawaii—with its policies encouraging conservation, demand response programs or energy efficiency—because it removes the conflict between regulation and policy goals to a significant degree. A revenue cap also allows for more pricing flexibility and is preferable when costs do not vary significantly with sales volumes or when volume changes are less predictable. Furthermore, a revenue cap (as in the case of a price cap) would incentivize utilities to minimize overall costs as revenues are fixed, and they could generate more profits by operating more efficiently and spending prudently. As mentioned earlier, Hawaii currently uses the revenue cap as part of the decoupling mechanism.

Under Conventional PBR, the utilities would determine the going-in rates for the first year of implementation, subject to approval by the PUC. As discussed earlier, the going-in rates are the basis to which the PBR formula is applied. Going-in rates are determined through the COS calculation and estimated independently from the PBR formula. The going-in rates would depend on the revenue requirements needed by utilities in serving their customers and operating profitably. Since the Project Team is proposing a revenue cap, the revenue requirements for the succeeding years (year 2 and 3 of the PBR term) would be adjusted based on an indexing formula that takes changes in inflation and productivity into account. More specifically, the formula is shown below:

$$(\text{REVENUE})_{\text{YearT}} = (\text{REVENUE}_{\text{YearT-0}}) * [1+(\text{inflation} - \text{productivity factor})] +/- \text{PIMs} +/- \text{RAM} +/- \text{ESM}$$

The inflation provides a mechanism through which the utility's revenues may be adjusted annually to reflect expected input cost increases. On the other hand, the productivity factor is the rate of change in efficiency that is expected or targeted. There is an expectation that if the utility achieves the productivity factor, then it would be able to earn its allowed rate of return. The productivity factor also serves as the mechanism by which customers reap the rewards of PBR (as it dictates the pace of real rate reductions).

A balancing account mechanism would be needed to capture the difference between the approved revenue requirements and the actual revenues.

Total expenditure approach

To address the PUC's objective of having a mechanism that results in *"efficient investment and allocation of resources regardless of classification as capital or operating expenses,"*[69] the totex approach**,** like in the UK's RIIO model, would be incorporated in the

[69] Public Utilities Commission. *Order No. 35411 Instituting a Proceeding to Investigate Performance-Based Regulation*. Docket No. 2018-0088. April 18, 2018. Page 52.

Conventional PBR. The concept of totex started in UK and was utilized to address the perceived utility bias towards capital expenditure ("capex") solutions.

RIIO's totex approach

Under the RIIO's totex approach, the utilities are incentivized to consider the whole life costs, rather than being driven to choose between capex and opex. A capitalization ratio is set between opex and capex that would be applied in the regulatory period. This ratio sets how much revenue will be expensed ("fast money") or added to the regulatory asset base ("slow money") at the onset of the regulatory period. By doing this, the utilities would be indifferent on whether to use opex or capex knowing that their decisions would not impact how the allowed revenue is determined.

Through the totex approach, utilities are incentivized to submit reasonable forecasts and to spend the allowance prudently. Utilities that submit forecasts that are closer to Ofgem's view of efficient costs, receive a higher totex incentive rate. This means that the utilities receive more of the underspend. Utilities that underspend get to keep the underspent amount. Ofgem expects that efficient spending leads to better returns for the investors and lower rates for customers.

Utilities need to report their actual totex to the regulator annually, explaining the actual performance compared to the allowed totex. According to the 2016-2017 Annual Report, the distribution utilities in UK have underspent their totex allowance by 7% or £531 million for the 2016-2017 period. According to Ofgem, a proportion of the underspend is due to efficiencies, which have effect of driving down the costs.

Sources: Ofgem. RIIO-ED1 Annual Report 2016-17 and Ofgem. RIIO Handbook.

Under a totex approach, there is no distinction between capital and operating expenditures. In this way, the utilities would be expected to use the most cost-effective solution. For instance, the utility would be encouraged to perform maintenance to avoid replacing an asset or use demand-side management to avoid building new capacity. The totex approach would also remove the incentive for utilities to reclassify costs from operating expenditure ("opex") to capex. In addition, it will also eliminate the issue of determining the boundaries between opex and capex, which entails a significant amount of time to perform and regulatory costs. The textbox below provides a brief overview of how the totex approach works in the UK.

PIMs

The same list of enhanced PIMs as well as reporting requirements would be included under Conventional PBR.

ESM

There would also be an **ESM** under Conventional PBR, although larger and symmetrical deadband and sharing percentages would be adopted. This means that the percentage share between the utility and the consumers would be the same (e.g., 50% for utility and 50% for

customers) and that the deadband for gains and losses would be the same (e.g., +/- 200 basis points). The reason for having a larger deadband under this model is to provide the utilities the opportunity to earn more given the higher risk of the indexing formula in determining the rates. Including the ESM would align with the PUC's aim of having a mechanism that results in "*fair distribution of risks between utilities and customers.*"[70]

3.5.4.3 Option C: Outcomes-based PBR

The third potential PBR option for Hawaii is Outcomes-based PBR, which is similar to the UK's RIIO model. Under this model, the **focus would be on setting the outcomes** (and incentives to deliver the outputs) by providing utilities the flexibility in producing the results (and determining inputs needed in achieving them). Revenues (and rates) would be forecasted for the next five (5) years using a building blocks approach.

Figure 25. Key features of Outcomes-based PBR

Outcomes-Based PBR	
Regulatory term	5 years
Rate-setting approach	Revenue cap using building blocks approach
Performance incentives mechanisms	Based on the outcomes to be achieved, the PIM list is more comprehensive than Light and Conventional PBR: • Customer satisfaction • Service quality • Customer engagement • Availability • Reliability • Safety • Cost control • Asset management • Connection of renewable generation • Connection of DERs • RPS target • Demand response implementation • Competitive Procurement • Financial Ratios
Earnings sharing mechanism ("ESM")	Similar to conventional PBR where ESM is symmetrical
Treatment of capital and operating expenditures	Totex approach

[70] Public Utilities Commission. *Order No. 35411 Instituting a Proceeding to Investigate Performance-Based Regulation*. Docket No. 2018-0088. April 18, 2018. Page 52.

Regulatory term

A **longer regulatory period (preferably five years)** would be more appropriate under Outcomes-based PBR to better align the setting of the rates and the planning horizon of the utilities. This extended term would also strengthen efficiency incentives and help manage the pace of rate increases for customers through adjustments that are calculated to smooth the impact of forecasted expenditures. Also, the longer period can motivate the utilities to adopt performance improvements and cost reductions further because the longer term would allow them to retain increased profits. Moreover, it would reduce regulatory costs and burden of filing another PBR plan only after a short period.

Outcomes and PIMs

Outcomes-based PBR has four (4) output categories, namely:

(i) **enhance customer experience**: provision of services in a manner that enriches customer service

(ii) **improve utility performance**: continuous enhancement in productivity, attainment of cost performance, and improved delivery on system availability, reliability, and quality objectives

(iii) **achieve public policies and goals**: compliance of utilities to obligations in legislation and regulatory requirements

(iv) **attain healthy financial performance**: maintenance of financial viability and sustained savings from operational efficiency.

Based on these outcomes, the performance categories and measures for each group would be determined. Figure 26 shows some examples of PIMs for each category. Unlike Light PBR, Outcomes-based PBR would require a more comprehensive list of PIMs. The Commission would need to have a **rigorous performance reporting and monitoring process** to determine if the expected outcomes are being achieved.

Under Outcomes-based PBR, the HECO Companies would be required to develop a **robust business plan** that sets out what they intend to deliver and achieve during the regulatory period. The plan should include target revenues from existing and future customers to ensure the achievement of outcomes. It would also provide evidence of the utility's cost and revenue forecasts and detailed investment plans for the regulatory period.

Furthermore, the HECO Companies would be expected to file **capital and asset management plans** to support their rate application. They would need to provide evidence that their planning and prioritization process is rigorous to justify the proposed capital budget. In particular, the plan should be able to explain how utilities sought to control costs in relation to its proposed investments, for example, through appropriate optimization and prioritization of investment expenditure. Utilities should also establish that the plans benefited from meaningful consultation with customers and stakeholders. The Commission would be expected to monitor capital spending against the approved plans by requiring utilities to report annually on actual amounts

spent. A large disparity between actual expenditures from those reflected in the plans could trigger a Commission investigation.

Figure 26. Indicative outcomes and potential performance categories and indicators in Outcomes-based PBR

Performance Outcome	Performance Categories	Performance measures
Enhance customer experience	Customer satisfaction	• Billing accuracy • First contact resolution
	Service quality	• Telephone calls answered on time • New customer connected on time
	Customer engagement	• No. of Consultations Conducted
	Availability	• Generation availability • Equivalent Forced Outage Factor • Equivalent Forced Outage Factor Demand
Improve utility performance	Reliability	• SAIFI • SAIDI • No. of times that power to a customer is interrupted
	Safety	• Number of general public incidents
	Cost control	• Cost of final delivered energy to customers by rate class for each island system • Total cost per customer • Total cost per km of wires
	Asset management	• Transmission plan implementation progress • Distribution plan implementation progress
Achieve public policies and goals	Connection of renewable generation	• No. of renewables connected on time
	Connection of DERs	• No. of DERs connected on time
	RPS target	• Percentage of renewables relative to total energy
	Demand response implementation	• Amount of demand response implemented
	Competitive procurement	• Timely conduct of a competitive procurement • Cost savings in renewable generation procurement
Attain financial performance	Financial ratios	• Leverage: Total Debt to Equity ratio • Liquidity: Current Ratio (Current Assets/ Current Liabilities)

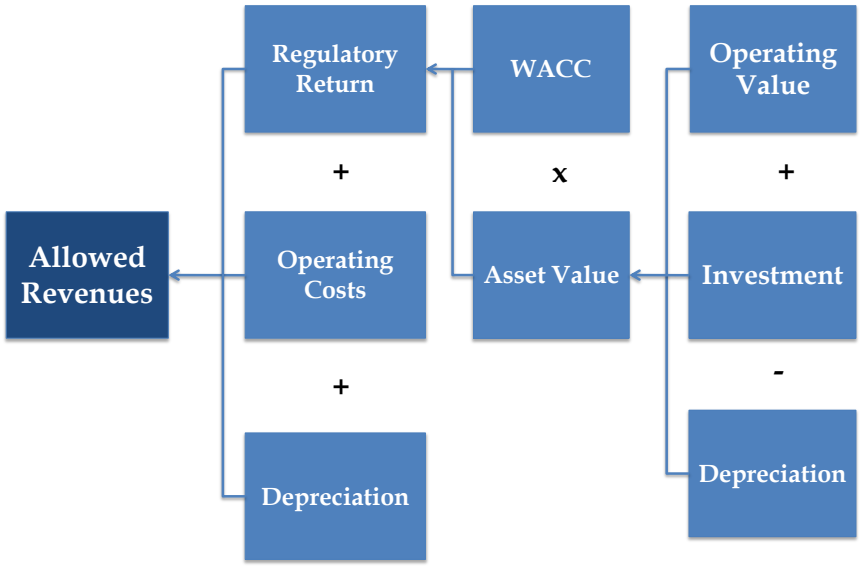
Revenue cap using building blocks approach

Similar to Conventional PBR, a revenue cap mechanism would be used in this model to align with the public policies and energy goals of the State. In contrast to Conventional PBR, however, Outcomes-based PBR would have **rates that are set based on a five-year forecast** of the utilities' revenue requirement and sales volumes. This means that unlike Conventional PBR where the rate

for the next two years of the regulatory period will increase by an indexing formula,[71] Outcomes-based PBR would already determine the revenue requirements and the rates for the next five years based on the utilities' revenue and sales forecasts.

Generally, a building blocks approach is used to forecast the revenues. This approach requires a forecast of total costs (e.g., operating expenses, return on investment, depreciation expenses, taxes, etc.) for each year of the regulatory term. The forecast considers productivity improvements and targets and necessary capital investment. These total costs would then be added together – hence, "built up" – to an allowed revenue requirement for the utilities based on estimates of the utilities' expected capital and operating costs and return of and return on asset base. Figure 27 shows how the allowed revenues are built up.

Figure 27. "Building up" allowed revenues under the building blocks model



The Commission would assess the proposed costs using historical performance metrics, benchmarks of unit costs, and industry-wide benchmarks (including industry total factor productivity studies). For example, regulators and utilities in Australia and the UK usually commission independent expert reports to assess the proposed expenditures that make up the forecast revenue requirements of each utility.

ESM and totex approach

[71] First year rate of the regulatory term is the going-in rate which is determined through a cost of service as discussed in

Figure 16. The rates for the second and third year are based on the indexing formula, which is based on the increase in inflation less approved productivity factor.

Finally, similar to the Conventional PBR, the symmetrical ESM and totex approach would also be incorporated in this option. See discussion Section 3.5.4.2 for the discussion on these mechanisms.

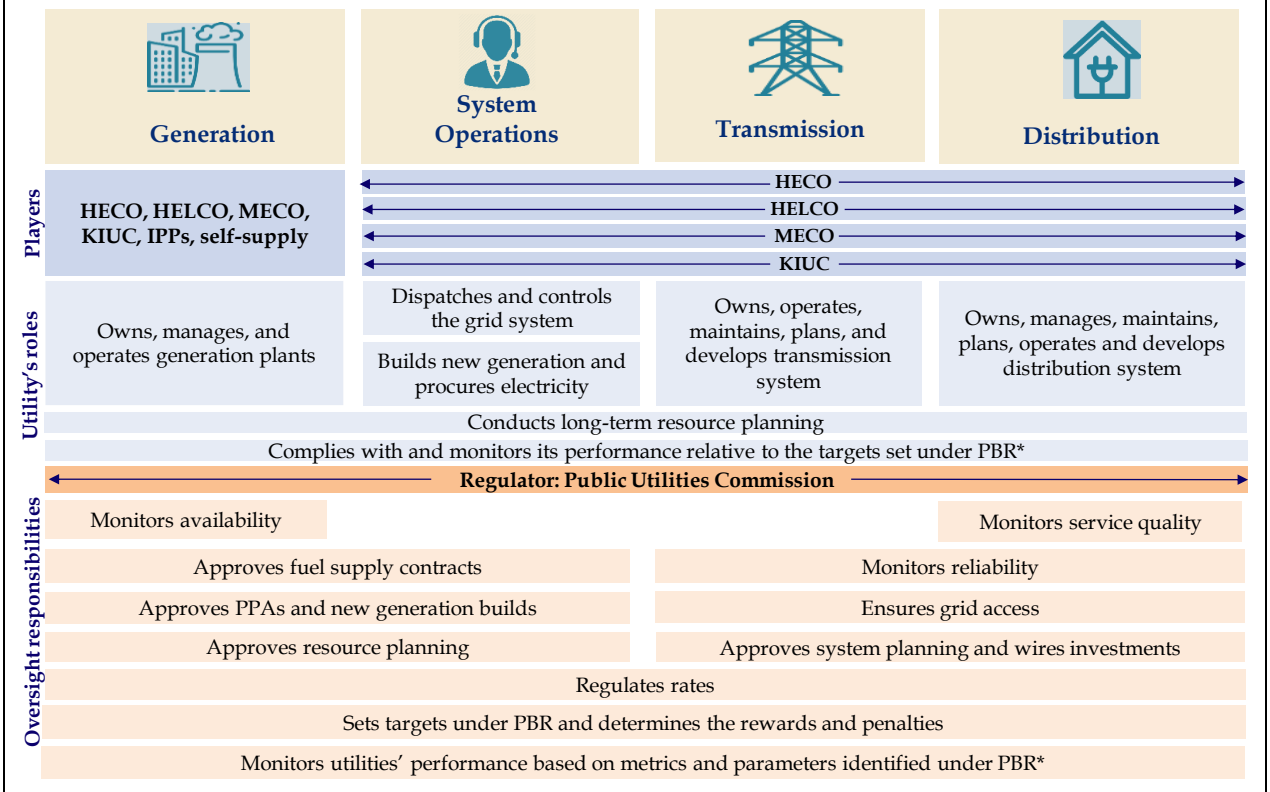
3.5.5 Oversight under PBR

The ownership model under a PBR model would remain the same where the incumbent vertically-integrated utilities would still own and operate the generation, transmission, and distribution assets. The PUC would administer the implementation of the PBR. These PBR oversight tasks would include:

- reviewing the PBR plan that the utilities will submit;
- identifying the performance indicators that will be used to measure the following: (i) cost control, (ii) efficient investment, (iii) "rapid" integration of renewables, and (iv) timely execution of competitive procurement;
- determining the targets that the utilities need to achieve for each metric identified above;
- setting up the rewards and penalties for attaining or missing the targets; and
- monitoring the actual performance of the utilities relative to the targets.

Figure 28 shows the graphical depiction of PUC's oversight under PBR.

Figure 28. Graphical depiction of the value chain under a PBR model



Note: *Except for KIUC

3.6 Lighter regulation for KIUC

Since KIUC is exempt from the PBR docket, the Project Team evaluated a separate regulatory model for KIUC – one with lighter PUC oversight compared to the status quo. Currently, KIUC is under the regulation of PUC (mostly similar to HECO Companies).

Despite a lighter oversight, KIUC would also need to meet specific metrics to remain in compliance with the Rural Utilities Services ("RUS") because it receives subsidized financing from the latter. The additional regulation from the PUC could be more targeted for the co-op business model, owing to its governance structure with direct accountability to its customer-members and RUS oversight. PUC's regulation on co-ops varies depending on jurisdictions. Reflecting the unique character of cooperatives as consumer-owned utilities, PUCs do not regulate tariffs in 31 of the 47 states in the US that have electric co-ops.[72]

As stated in the *2016 - 2030 strategy plan*, KIUC "*began to consider moving out from under the authority of the PUC to a deregulated or minimally regulated status, which would allow us greater flexibility in responding to member concerns and unexpected changes in fuel prices and market conditions.*"[73] As part of the "*strategic goals and actions*," KIUC will "*consider and potentially seek increased exemption from regulation by the PUC through changes in State law or PUC order.*"[74] Hawaii Revised Statutes § 269-31 states that "*the public utilities commission and the consumer advocate shall at all times consider the ownership structure and interests of an electric cooperative in determining the scope and need for any regulatory oversight or requirements over such electric cooperative.*"[75]

Under a lighter regulation model, regulations would be relaxed for KIUC. KIUC would be exempted from PUC regulations such as approval of rate setting and design, power purchase agreements with independent power agreements, fuel contracts and large capex, if such transactions or activities would not exceed particular thresholds. KIUC's Board of Directors would continue to approve operating and capital budget, develop resource plans (that take the interest of the members into account), and ensure adequacy of electricity. Nevertheless, KIUC will still be required to meet the State's energy goals.

Aside from the Board of Directors, KIUC's corporate leadership would remain accountable to the following entities:

- *KIUC members*: annual meeting of members is held for reviewing the financial progress of the KIUC for the prior calendar year, and transacting any other business as may be

[72] USAID and NRECA International. *Guides for Electric Cooperative Development and Rural Electrification*. Page 8.

[73] KIUC. *Strategic Plan Update 2016 – 2030.* January 31, 2017 adopted. Page 4.

[74] Ibid. Page 5.

[75] HRS § 269-31.

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designated in the notice of the meeting.[76] Also, special meetings of members may be called by (i) the Board of Directors, (ii) the Chairman, or (iii) 5% of all members or 250 members, whichever is less. Except for any motion, resolution or amendment for which a recorded vote is authorized, 5% of the members shall constitute a quorum necessary to the transaction of business to be voted on by the members at any annual or special meeting of the members.[77] Each member has one vote upon each matter submitted to a vote at a meeting of the members.[78]

- *RUS*: KIUC receives low-cost financing from RUS, allowing it to pass the lower cost of capital to consumers. However, these loans have covenants regarding coverage ratios and capital requirements that KIUC is obligated to meet to maintain its access to low-cost capital.[79] In addition, KIUC also submits its construction plans to RUS for review and approval.[80]

An indicative approach to light-handed co-op regulation includes, but is not limited to:

- annual timely filing of financial and performance metric documents;
- KIUC compliance with State policies unless there are explicit exemptions;
- seeking of approval if KIUC wishes to pay a salary higher than HECO Companies for any similar position;
- the opening of PUC investigation in the following events (or similar cases):
    - when rate increases exceed the higher of 5% or 2 times the State Consumer Price Index, and 5[x] or more ratepayers object to PUC, PUC may open an investigation;
    - when the capex spent increases beyond the set threshold;
    - if ratepayers provide evidence of rate discrimination; and

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[76] KIUC. *Seventh Revised and Restated By-laws of KIUC - Meetings of Members and Voting*. Website. Access Date: July 11, 2018. Website. <http://website.kiuc.coop/content/bylaws>

[77] Ibid, Section 5 - Quorum.

[78] Ibid, Section 4 – Voting.

[79] KIUC. Board Policy No. 29. Equity Management Planning. March 24, 2015. Page 4. <http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/bp/BP29-rev2015-0324-%20EMP.pdf>

[80] KIUC. Regular Meeting of the Board of Directors on September 27, 2016. Minutes. Page 19. <http://website.kiuc.coop/sites/kiuc/files/PDF/minutes/minutes-2016-0927-DRAFT.pdf>

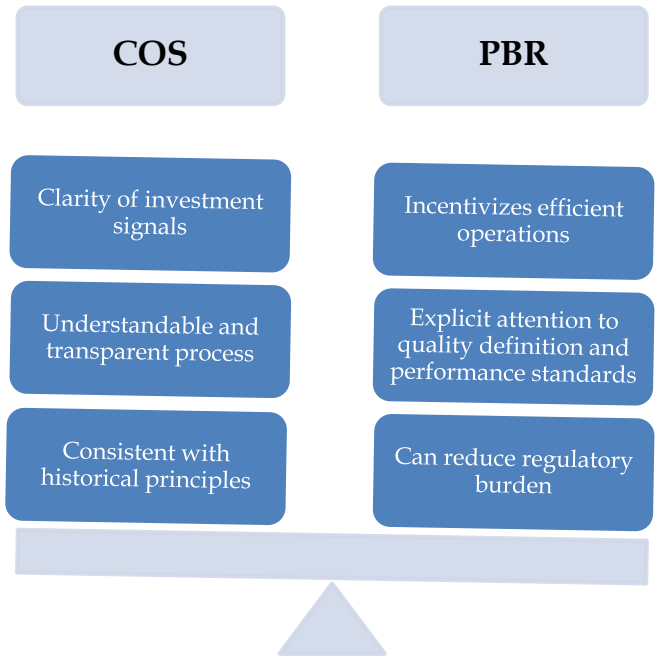
- if the customer has exhausted KIUC internal dispute resolution processes and continues to feel KIUC has acted contrary to their policies, PUC guidelines, or the State law.

4 Appendix A: PBR design

4.1 COS and PBR

Under a PBR regulatory approach, COS analysis and COS ratemaking principles continue to be significant. COS elements are vital inputs to PBR regulation: PBR regimes begin with a COS-based analysis of what the "going-in" rates should be. Moreover, COS principles, such as the opportunity for full cost recovery and commercially reasonable return on equity ("ROE") targets, are still important tenets under PBR. Although under the harder forms of PBR, the annual revenue requirement and rate base calculations do not directly figure into the rates, a COS analysis is required at the end of each generation for PBR, known as the "re-basing" review, which serves as the basis for "going in" rates.

Figure 29. COS versus PBR



4.2 Price cap vs. revenue cap

Under a price cap, which is also called price indexing or rate indexing, the regulator approves a formula that determines how fast rates can increase. The regulator sets an initial price $(PRICE)_{Year1}$ and the rates are adjusted for each year considering changes in inflation and productivity (or X-factor). The inflation factor, which is driven by macroeconomic forces that are beyond the control of the utilities' management, is passed on to customers. The productivity or X-factor, on the other hand, is the rate of change in efficiency that is expected or targeted. There is a presumption that if the utilities achieve the productivity factor, then they will be able to earn its allowed rate of return. The productivity factor also serves as the mechanism by which customers reap the rewards of PBR as it dictates the pace of real rate reductions.

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Price caps are usually applied to any of the following: the utilities' average price, the average prices for each customer class, or to each rate element of each rate schedule. This provides the utilities a degree of flexibility in how to optimize specific customer rates and consider cost allocations.

Price caps have several advantages. First, price caps provide incentives for cost efficiency and cost reduction.[81] The cost-reducing incentives of price caps are relatively stable and viable because they can hold over an extended period and they have built-in adjustments (I - X) that do not endanger the utilities' finances.[82] Second, regulators under price caps do not need detailed information about the utilities' cost functions to calibrate the price cap parameters.[83] Third, utilities under a weighted average price cap approach have the flexibility to change relative prices in the regulated basket of services. The use of baskets has *"provided utility[ies] with the ability and incentive to rebalance their prices in the direction of allocatively superior prices and has allowed regulated utilities to compete with new entrants."*[84] Finally, price caps could provide incentives for utilities to meet and expand demand because revenues are not capped as they would be under a revenue cap approach. Utilities will have an incentive to increase sales if the marginal revenue accompanying the increased service provision is higher than the marginal cost of increased service provision. However, this contradicts demand management plans where energy savings and energy efficiencies are encouraged.

On the other hand, as mentioned earlier, the **revenue cap** regulates the maximum allowable revenue that a utility can earn. Under a revenue cap, revenue requirement in a given year is established according to the previous year's revenue requirement and adjusted based on a predetermined formula, considering changes in inflation and productivity.

Under a revenue cap, there is no incentive for utilities to maximize sales but there is still an incentive to minimize overall costs (i.e., with revenues fixed, profits increase if costs are cut), making it arguably more compatible with utilities (like those in Hawaii) that are facing substantial demand response programs or energy efficiency reductions in consumer demand. Moreover, with a revenue cap, utilities are generally exposed to lower levels of risk related to changes in demand or sales.[85] Revenue cap regimes provide more pricing flexibility and are preferable when costs do not vary significantly with sales volumes. Finally, the ability to make additional profits

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[81] Lantz, Björn. "Hybrid Revenue Caps and Incentive Regulation." *Energy Economics* 30 (2008): 688-695. September 25, 2006. Page 688-694.

[82] Vogelsang, Ingo. "Incentive Regulation and Competition in Public Utility Markets: A 20-Year Perspective." *Journal of Regulatory Economics* 22:1 (2002): 5-27. Page 8.

[83] Ibid.

[84] Ibid.

[85] National Association of Regulatory Utility Commissioners. *Performance-Based Regulation for Distribution Utilities*. December 2000. Page 23.

due to increased scale is removed under a revenue cap regime, along with any means to adjust revenue if costs increase with volumes.

Price cap and revenue cap regimes could converge if various true-up mechanisms are deployed. Price caps often incorporate measures to protect utilities and customers against weather and economic growth-related volume fluctuations. Revenue caps might contain adjusters if utilities' experiences sustained and unexpected volume increases that require additional capital expenditure.

4.3 Approach to designing rate cap

There are generally two approaches for rate-setting under a price cap regime: (i) **total factor productivity ("TFP") based I-X approach;[86] and (ii) the building blocks approach.**

The **TFP-based I-X approach** was developed as a relatively simple mechanistic, yet empirically "rich," approach to adjusting rate caps and providing incentives. The primary view that grounds most TFP-based applications of PBR models is that firms should be able to improve productivity consistent with measured long-term productivity improvements (historically) for the industry. In North America, the TFP-based approach to an I-X rate cap is generally used.[87]

Under the TFP-based I-X approach, prices for the forthcoming regulatory period are set in relation to a historical productivity trend, which is usually obtained from a statistical study of a group of comparator firms. The price that the utilities can charge is fixed in advance for a certain period, and price may increase by no more than the inflation less the X-factor.

This approach is suited for utilities facing steady state of operating and capital investment profile as it provides for a reasonably stable rate of change in the price or revenue cap because the I factor is generally not volatile and the X-factor is often fixed. Under steady state conditions, economists expect typically the utility sector to be able to gradually improve its productivity over time – driven by any or all of the following: technological change, allocative efficiency, improved capacity utilization, economies of scale, or elimination of efficiencies. However, from time to time, to the extent that the pace with which the utilities are making investments in capital and deploying labor exceeds the speed of demand and customer growth, then the rate of change in productivity will take on a negative value. Furthermore, revenue requirements and adjustment parameters are often related to historical studies in which regulators determine parameters for the IR plan; these studies may have limited relationship to or fail to predict future trends.

The **building blocks approach,** on the other hand, has been the cornerstone of PBR in Australia and the UK for over 20 years now. First introduced in the early 1990s in the UK, the building blocks approach was developed to derive the components of the price cap regime (RPI-X) that

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[86] TFP-based I-X approach is not the only option. Other options include but not limited to retail price index or consumer price index minus a productivity factor ("X").

[87] For example, most of the PBR pioneers in the US, i.e., California, Maine, and Massachusetts used the TFP-based approach in 1990s. Source: *Discussion Paper on Rate Regulation in Ontario*. Website. <http://cf.oeb.ca/documents/consultatation_ontariogasmarket_rateregulation_070904.pdf.>

the regulator wanted to apply to newly privatized, monopoly industries, commencing with telecommunications, and then expanding to other network industries in gas and electricity.

Under this approach, a forecast of total costs is prepared (e.g., operating expenses, return on investment, depreciation expenses, taxes, etc.) for each year of the regulatory control period (i.e., PBR term). The forecast considers productivity improvements and targets and necessary capital investment. After this procedure, these total costs are added together - "built up"- to an allowed revenue requirement for a utility based on estimates of the utility's expected capital and operating costs and return of and return on asset base.

The revenue requirement is then translated into a starting price (for the price or revenue cap) referred to as P_0 and an annual rate of change is estimated over the term of the PBR plan to adjust the price cap/revenue cap. The annual adjustment is referred to as I-X in Australia and RPI-X in the UK. The I-factor is the inflation adjustment. Meanwhile, the estimated X-factor reflects both the productivity target and the real price change required to support a utility's revenue requirement. This reference to an X-factor can be confusing in the North American context because it is not solely a measure of productivity but reflects an aggregated view of efficiency trends across total costs and the need for efficient capital investment and (potentially) rate smoothing.

One of the most significant challenges associated with the building blocks approach is the reliance on forecasts. Related to this challenge is the difficulty on the side of the regulators to gather complete information about the costs of each utility; this weakens their ability to estimate the actual level of the utilities' efficient costs. The utility may use this advantage during the regulatory review process to try to increase its profits. This could result in higher costs and prices, which could be set above the level indicative of efficient costs.[88]

[88] London Economics International. "Literature review: regulatory economics and performance-based ratemaking." Nova Scotia Department of Energy and Mines. Web. <https://energy.novascotia.ca/sites/default/files/files/Literature%20Review%20-%20LEI%20Consolidated.pdf>

5 Appendix B: Scope of work to which this deliverable responds

Task 2.1.1 Summary comparison of Regulatory Models from Hawaii's perspective, including a graphical depiction of each regulatory model and comparison.

CONTRACTOR shall provide a brief narrative introduction of each regulatory model.

DELIVERABLE FOR TASK 2.1.1. CONTRACTOR shall provide its conclusions and all work related to providing an initial narrative introduction of each potential regulatory model that Hawaii could consider, including, but not limited to: status quo, status quo with increased oversight, distribution focused regulatory model (REV), and performance-based regulation model. CONTRACTOR shall provide results of discussions with DBEDT and other stakeholders about key priorities of a regulatory model. CONTRACTOR shall also provide information on how each model operates and how the oversight of the different components of the electric power value chain is managed. The deliverable shall be an MS Word document which summarizes the above, includes an intuitive graphical depiction of each regulatory model and comparison, and a list of potentially relevant jurisdictions that use each of the regulatory models. CONTRACTOR shall submit deliverable for TASK 2.1.1 to the STATE for approval.

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High-level and general assessment of the existing regulatory model in place in Hawaii

working paper prepared by London Economics International LLC for the State of Hawaii with support from Meister Consultants Group

May 30, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that evaluates the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals; this document, which corresponds to Task 2.1.2., is one of several working papers associated with that engagement. This paper provides a general assessment of the existing regulatory model in place in Hawaii. Electric utilities in Hawaii are regulated by the Public Utilities Commission while the Hawaii State Energy Office assists in developing and implementing the policies as mandated by the legislature. Generally, electricity rates for the HECO Companies are determined through a cost of service ("COS") approach with some variations and includes components associated with performance-based regulation such as the earning sharing mechanisms, penalties for not achieving certain performance standards (but mostly in reliability), decoupling and multi-year rate plan, while rates for the KIUC are determined using the Times Interest Earned Ratio ("TIER") level. The strengths of the current regulatory model include PUC's independence and innovativeness, participatory regulatory process, the regulatory model allows rates to be set to allow utilities a reasonable rate of return, and policies are in place to achieve diversifying the state's energy portfolio. Areas for improvements include providing incentives in utilities' performance, providing certainty with regards to timeline on issuing regulatory decisions, reducing complexity and cost of regulation and regulatory compliance and mitigate risks in the establishment of the final design of the Performance-Based Regulation ("PBR").

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List of acronyms

CGS	Customer Grid-Supply
CGS +	Customer Grid-Supply Plus
COS	Cost of Service
CSS	Customer Self-Supply
DBEDT	Hawaii Department of Business Economic Development and Tourism
DCA	Hawaii Division of Consumer Advocacy
EIA	US Energy Information Administration
ERCOT	Electric Reliability Council of Texas
ESM	Earnings Sharing Mechanism
FERC	Federal Energy Regulatory Commission
HECO	Hawaiian Electric Company, Inc.
HEI	Hawaiian Electric Industries
HELCO	Hawaii Electric Light Company, Inc.
HRS	Hawaii Revised Statutes
HSEO	Hawaii State Energy Office
IOU	Investor-owned utility
IPPs	Independent power producers
IRS	Interconnection requirements study
ISO	Independent system operator
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company, Ltd.
NEM	Net energy metering
NERC	North American Electric Reliability Corporation
PBR	Performance-based regulation
PIMs	Performance incentive mechanisms
PUC	Public Utilities Commission
RAM	Revenue Adjustment Mechanism
RBA	Revenue Balancing Account

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ROE	Return on Equity
RPS	Renewable portfolio standards
RSWG	Reliability Standards Working Group
RTO	Regional transmission organization
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index

1 Executive summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that evaluates the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which responds to Task 2.1.2 in the project scope of work, provides an overview and general assessment of the existing regulatory model in Hawaii.

Each of the counties in Hawaii is served by a vertically integrated utility: Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), Maui Electric Company, Ltd. ("MECO"),[1] and Kauai Island Utility Cooperative ("KIUC").[2] These utilities are also the major generators in their respective counties as well as the owners and operators of the transmission and distribution assets in their respective service areas. Generation in the State is also provided by several independent power producers ("IPP") as well as customer-sited and/or owned distributed generation ("DG").

The electric utilities in the State are regulated by the Public Utilities Commission of the State of Hawaii ("PUC"). More specifically, the PUC:

- regulates public utilities' rates, terms and conditions of service, performance, and compliance with laws and regulations;
- reviews applications for approval to construct transmission lines, to make large capital expenditures, to issue stocks and bonds, notes and other evidence of debt;
- reviews purchases, acquisitions, sales, or other disposition of utility assets, including mergers and acquisitions involving the utility company;
- oversees and monitors the electric reliability, utility's service, operations (*e.g.*, safety), and resource planning;
- initiates and conducts investigative proceedings;
- provides guidelines on various standards and regulations such as interconnection standards, procurement of generation, and performance-based regulation ("PBR") to name a few;
- implements state policy;

[1] As mentioned in Task 1.1.3., Kalawao County is a judicial district of Maui County and has limited electricity system facilities. For discussion purposes, Kalawao is included under the County of Maui.

[2] HELCO and MECO are subsidiaries of HECO; HECO, HELCO, and MECO will be collectively referred to as the "HECO Companies.")

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- develops and adopts administrative rules in administrative rulemaking proceedings; and

- generally enforces public utility laws and regulations.

The State government (Legislature and Governor) establishes the energy policies, legislative enactments, and resolutions that are further developed, implemented and enforced by the PUC. The Hawaii State Energy Office ("HSEO"), within the Department of Business Economic Development & Tourism ("DBEDT"), assists in developing and implementing energy policy as may be provided by the State. The roles and responsibilities of the PUC and the Division of Consumer Advocacy, Department of Commerce and Consumer Affairs ("Consumer Advocate") are discussed in Section 3.2.

Recently, Governor David Ige signed into law the Ratepayer Protection Act.[3] The new law orders the PUC to create "performance incentives and penalty mechanisms" by January 1, 2020, that break the direct link between allowed electric utilities' revenues and investment levels. Related to the Ratepayer Protection Act, the PUC initiated a proceeding to Investigate Performance-Based Regulation, on April 18, 2018.[4] The PUC stated in Order 35411 that they are interested in PBR mechanisms that result in greater cost control and reduced rate volatility, efficient investment and allocation of resources regardless of classification as capital or operating expenses, fair distribution of risks between utilities and customers, and fulfillment of state policy goals.[5] This investigative proceeding only applies to the HECO Companies and not to KIUC, a cooperative in Hawaii.[6] This will be discussed in Section 3.5.

Electricity rates for the HECO Companies are generally determined through a cost of service ("COS") (sometimes referred to as "rate return regulation") approach with some components associated with performance-based regulation such as the earning sharing mechanisms ("ESM"), penalties for not achieving certain performance standards (mostly in reliability), and multi-year rate plan.

The Project Team evaluated the strengths and weaknesses based on the key characteristics of a regulatory model and its performance relative to the policy goals for electricity sector established by the State. Hawaii's current regulatory model's strengths include the following, which will be discussed in detail in Section 4.1:

- PUC's independence and adaptable to the changes in the regulatory environment;

- public participation in the regulatory process;

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[3] *See*, Section 3.5 discussion on the Future of Hawaii-specific performance-based regulation.

[4] *See*, Section 3.5 discussion on the Future of Hawaii-specific performance-based regulation; Docket No. 2018-0088, Order No. 35411, issued April 18, 2018 ("Order No. 35411").

[5] Order No. 35411, at 52.

[6] Order No. 35411, at 9-10.

- utilities are performing as expected in terms of providing reliable service;
- rates are set to allow the utilities an opportunity to earn a fair return;
- policies are in place to diversify the state's energy portfolio; and
- the proposed PBR will be able to help achieve the clean energy goals if designed correctly.

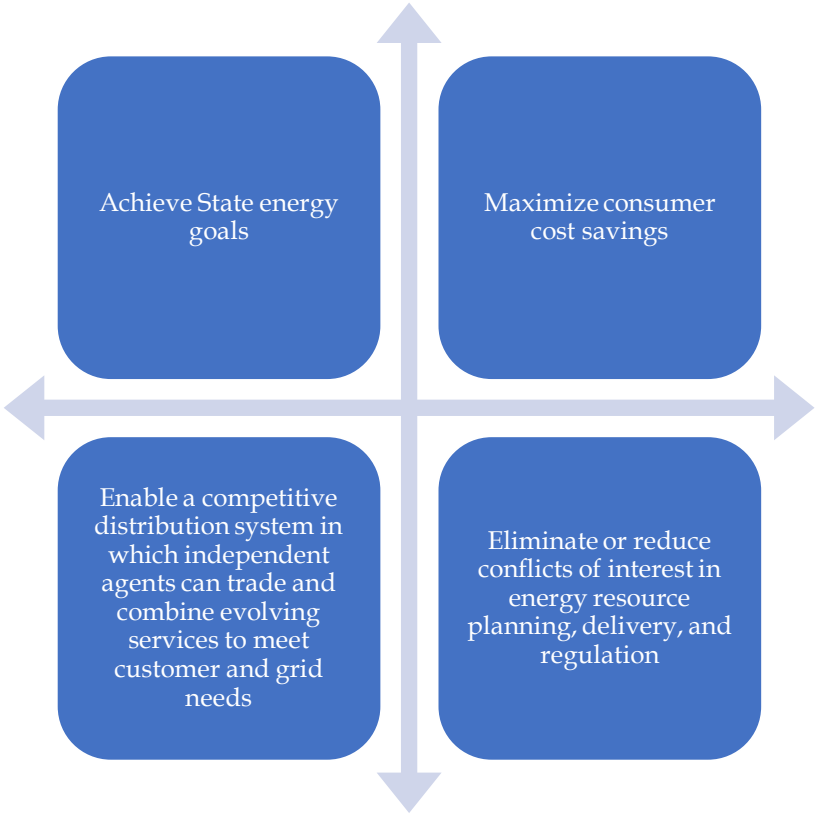
The areas of improvements in the current regulatory model include providing incentives for performance metrics, providing certainty with regards to issuing decisions; and considering other elements of PBR to provide a degree of protection to both the utilities and the ratepayers and to mitigate risks. These mechanisms include re-openers, exogenous factors (or "z-factors"), and true-ups. These will be discussed in detail in Section 4.2.

2 Introduction and scope

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission on a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[7] was contracted to perform this study.[8]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[9] listed in Figure 1.

Figure 1. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

The study will help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition,

[7] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[8] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[9] House Bill No. 1700 Relating to the State Budget.

it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[10]

This deliverable is responsive to Tasks 2.1.2 in the project scope of work.[11] It assesses the existing regulatory model in place in Hawaii and provides a high-level assessment of the strengths and weaknesses of the current regulatory framework.

[10] Hawaii Contract No. 65595. Scope of Services.

[11] This task involves a high-level overview, which may not include all of the detailed nuances, conditions and exceptions that may apply under certain circumstances, which are beyond the scope of this task.

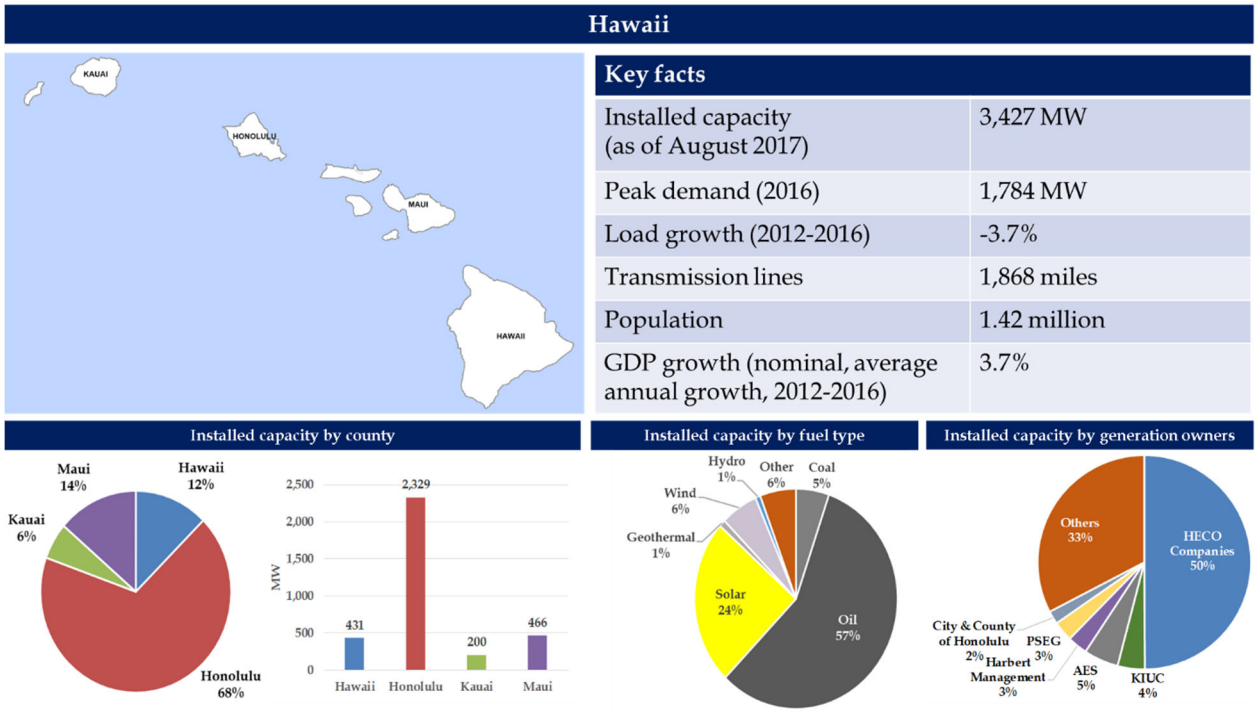
3 Overview of the current regulatory regime in Hawaii

Generally speaking, the regulatory framework in this context refers to the policies, laws and regulations and orders adopted by the State and its agencies to regulate and oversee energy policy and public utilities in the State of Hawaii. This includes statutes enacted into law by the State (by the Legislature and the Governor) that provide mandates, guidance, and authority to State agencies to implement and develop (where authorized), energy policy in Hawaii, and impose certain conditions and requirements on private parties such as regulated electric utilities. The regulatory framework includes rules adopted, and orders issued, by the PUC to implement policies, laws, and regulations. Other government entities also contribute to and are involved in the regulatory process as discussed below.

3.1 Overview of the energy market in Hawaii

As described above, each of the four major counties in the State - the City and County of Honolulu, County of Hawaii, County of Maui, and County of Kauai - are served by vertically integrated public utilities: HECO (City and County of Honolulu), HELCO (Hawaii County), MECO (County of Maui), and KIUC (County of Kauai).

Figure 2. Snapshot of the Hawaii market



Sources: HECO Companies website; KIUC website; HECO Companies' Power Supply Improvement Plans; 2016 State of Hawaii Data Book; HSEO Facts and Figures May 2017

As of August 2017, Hawaii has a total capacity of 3,427 MW.[12] In 2017, approximately 69% net capacity is served by oil, 13% by coal, 3% by biomass, 13% by wind, solar, geothermal, hydroelectric, and biomass, and the 4% by other means.[13] The City and County of Honolulu has the largest installed capacity among the counties, which represents nearly 70% of the State's installed capacity.[14] The HECO Companies own about 50% of the installed capacity in the State, and the subsidiaries are the dominant player in the county that they serve.[15] There are also several IPPs that provide firm generation and variable (as-available) generation[16] as well as customer-sited solar (*i.e.*, DG) in the state.[17]

As discussed in Task 1.5.1., the HECO Companies projected a relatively flat load growth for the next five years in the counties that they serve. Oahu's load growth is projected to decline on average from 2017 to 2021 while Molokai's load growth is relatively flat for the next five years. Load growth (peak demand in terms of MW) in Maui and Hawaii are less than 1% per year at an average of 0.97% and 0.78%, respectively. Only Lanai's load growth is expected to be higher than 1%. KIUC does not appear to have publicly available load forecasts.

The electrical grid on each island is not connected to any other island. The HECO Companies own significant generation, transmission, and distribution assets in each of the counties that they serve. The HECO Companies are investor-owned utilities ("IOU") that supply power to approximately 95% of Hawaii's population.[18] KIUC is a member-owned electric utility cooperative ("co-op").[19] Figure 2 provides an overview of the electricity market in Hawaii.

3.2 Institutions

The main institutional entities involved in the Hawaii electricity market and its regulatory framework are the State Government (Legislative and Executive), the PUC, the Consumer

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[12] Analysis of generation system is based on data from Hawaiian Electric Companies' 2016 Power Supply Improvement Plan ("PSIP"), SNL, KIUC website, KIUC 2017 Capital Improvements Program for Ensuing Five years, HECO Power Facts, and Power Purchase Contracts data from HEI.

[13] *Hawaii's Electricity Production by Source (Source: EIA)*, Hawaii State Energy Office Website, available at http://energy.hawaii.gov/resources/dashboard-statistics (Last visited May 9, 2018).

[14] *See HECO's Power Facts*, Hawaiian Electric Company's Website, available at https://www.hawaiianelectric.com/about-us/power-facts (Last visited May 9, 2018).

[15] *Ibid*.

[16] *Ibid.*

[17] *Ibid.*

[18] *Ibid.*

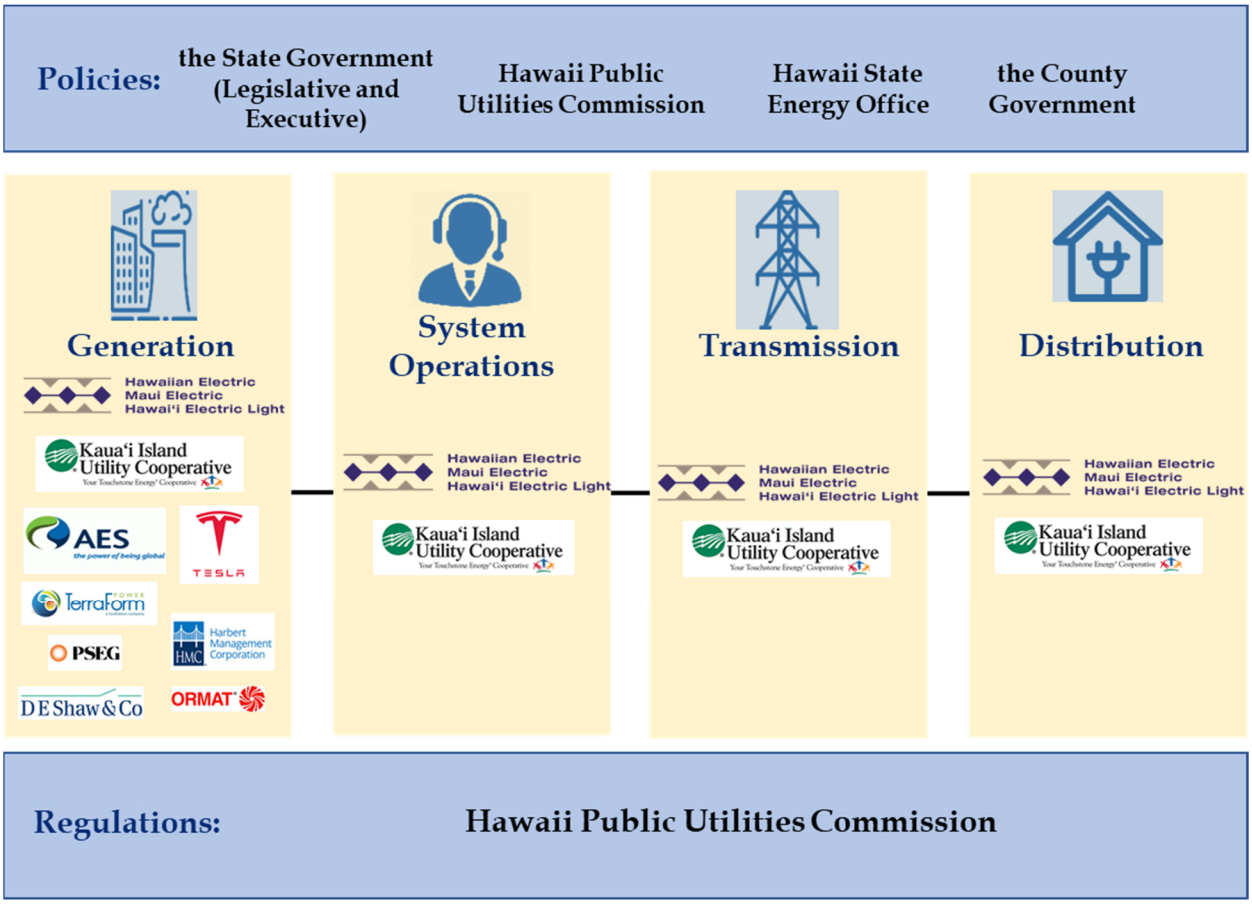
[19] *See Energy Page*, State of Hawaii Public Utilities Commission, available at http://puc.hawaii.gov/energy/ (Last Visited May 9, 2018) ("Collectively, HECO, MECO and HELCO are known as the 'HECO Companies' and serve about 95% of the State's population. KIUC on the island of Kauai serve about 5%.")

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Advocate, and the HSEO.[20] The HECO Companies and KIUC are regulated public utilities that are regulated by the PUC.[21]

Figure 3 shows the simplified electricity market structure and the players in the State.

Figure 3. Overview of electricity market structure in Hawaii



Note: The list of generation companies above is not exhaustive and should not be interpreted to only refer to utility-scale generation, as distributed generation ("DG") is an important and significant segment of supply.

[20] Unlike other states on the mainland, Hawaii is not under the jurisdiction or oversight of Federal Energy Regulatory Commission ("FERC") or the North American Reliability Corporation ("NERC"). See 16 U.S.C. § 824. Also, in Hawaii, county governments do not have authority to regulate the public utilities, but they may participate at times in proceedings before the PUC[should the report reflect that the Counties can indirectly affect utility regulation such as through ordinances related to land use, construction permits?]. *See, e.g.*, Order Granting Intervention, in Dkt No. 2008-0273, filed on November 28, 2008 (Order grants the City and County of Honolulu intervenor status in a proceeding to investigate the implementation of feed-in tariffs).

[21] *See* Energy Page, State of Hawaii Public Utilities Commission, available at http://puc.hawaii.gov/energy/ (May 9, 2018); *See also* HRS § 269-9.

3.2.1 Public Utilities Commission

The PUC in Hawaii, as in other jurisdictions, exercises broad regulatory powers by utilizing its rulemaking authority[22] to adopt and implement rules and regulations that are applicable electric utilities and by using its enforcement and quasi-judicial authority in docket or case proceedings involving public utilities.[23] These proceedings are undertaken in administrative rulemaking processes[24] or formal docket processes.[25] The PUC's primary role is to "protect the public interest by overseeing and regulating public utilities to ensure that they provide reliable service at just and reasonable rates."[26] Its stated mission is to:

"…. provide effective, proactive, and informed oversight of all regulated entities to ensure that they operate at a high level of performance so as to serve the public fairly, efficiently, safely, and reliably, while addressing the goals and future needs of the State in the most economically, operationally, and environmentally sound manner, and affording the opportunity for regulated entities to achieve and maintain commercial viability."[27]

HRS Chapter 269 defines and governs the PUC's general functions, responsibilities, staffing, and reports as well as specific policies regarding Renewable Portfolio Standards ("RPS"), Net Energy Metering ("NEM"), Electric Reliability, and Green Infrastructure Bonds, etc. Besides statutes, the PUC regulates the utility companies through its General Orders (such as GO 7), Hawaii Administrative Rules (such as HAR 6-60), and the PUC's orders and decision and orders."

Source: *Relating to Renewable Energy Standards*, HB 623 SD2 CD1, 28th Hawaii Legislature (July 1, 2015); codified in HRS § 269-92; HRS 269-101 *et. seq.*; HRS § 269-161 *et seq.*; PUC General Order No. 7; *Hawaii State Energy Profile*, U.S. Energy Information Administration, available at https://www.eia.gov/state/print.php?sid=HI (Last visited May 11, 2018).

Note: The Commission has been gradually replacing General Orders with Hawaii Administrative Rules

[22] *See* HRS § 269-6(a).

[23] *See* HRS §§ 269-6, -7, and HRS Chapter 269 generally.

[24] *See* HRS § 269-6(a); HAR §§ 16-601-146 to -155.

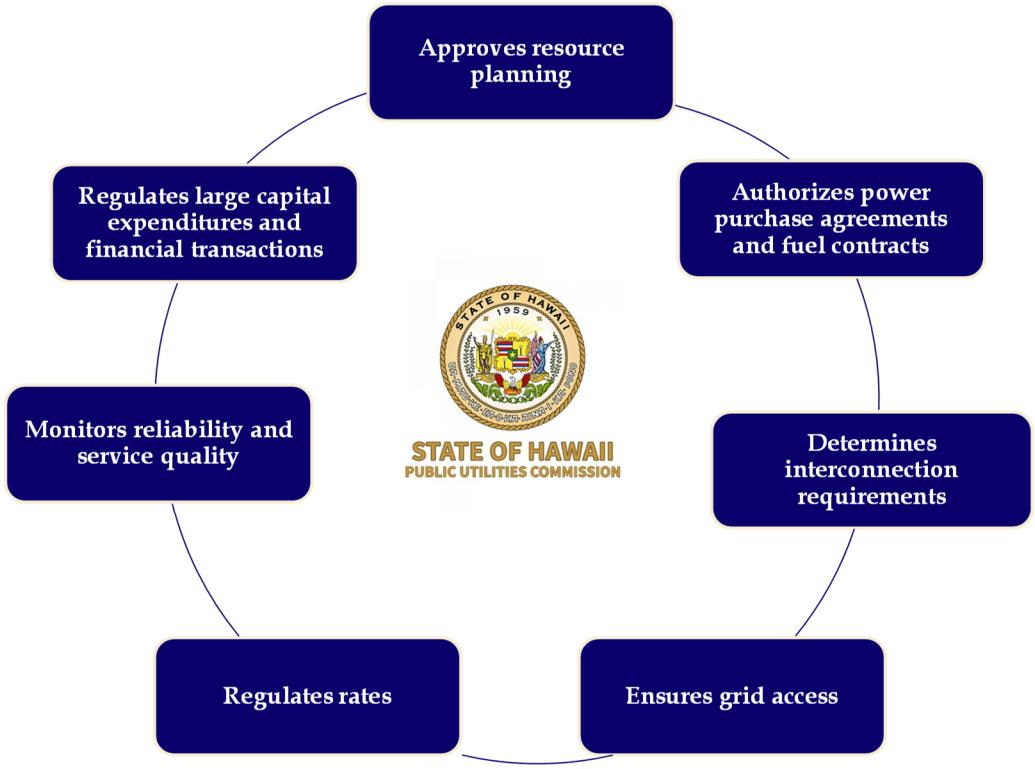
[25] *See* HRS Chapter 269, HAR Title 16 Chapter 601-1.

[26] *Introduction*. Available at http://puc.hawaii.gov/about/introduction/ (last visited April 9, 2018).

[27] *Goals and Objectives of the Commission*, State of Hawaii Public Utilities Website, Available at http://puc.hawaii.gov/about/introduction/ (Last Visited May 18, 2018).

The powers of the PUC include regulating the utilities' rates,[28] reviewing public utility requests for approval of proposed mergers and acquisitions of utilities,[29] authorizing the construction of transmission lines,[30] monitoring the electric reliability,[31] assessing the conditions of each utility in terms of how it operates,[32] regulating its issuance of stocks, bonds, notes and other evidence of indebtedness,[33] and generally investigating utilities as it deems necessary.[34] The most relevant roles will be discussed in the subsections below.

Figure 4. Tasks of the PUC in the electricity sector



[28] HRS § 269-16.

[29] HRS § 269-19.

[30] HRS §§ 269-27.5 and -27.6.

[31] HRS §§ 269-143(a).

[32] HRS § 269-6.

[33] HRS §§ 269-17 through -18.

[34] HRS § 269-7.

As discussed in Tasks 1.3.4. and 1.4.3, the PUC is comprised of three commissioners and each of the commissioners serves a six-year term on a staggered basis.[35] The Governor appoints each of the commissioners, subject to Senate confirmation,[36] and designates the chairperson of the PUC.[37]

3.2.1.1 Rates

One of the primary functions and roles of the PUC is to regulate rates charged by public utilities, which must be "just and reasonable," filed with the PUC and published by the public utility as directed by the PUC.[38] Ratemaking and the ratemaking process are discussed below in Section 3.4.

3.2.1.2 Capital expenditures

Generally, PUC approval is required for HECO Companies' commitments for major capital expenditures, fuel contracts, and power purchase agreements.[39] More specifically, in Hawaii, PUC pre-approval is required for capital expenditures greater than $2.5 million for electric utilities.[40] Usually, the PUC will determine whether the proposed commitment of funds is reasonable and in the public interest.[41] The utility will seek to have the proposed capital expenditures included in its rate base.[42]

3.2.1.3 Financing

The utilities are also required to obtain the Commission's approval before entering into certain types of financing transactions.[43] These transactions include issuing obligations, stocks, revenue

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[35] HRS § 269-2.

[36] HRS § 269-2, § 26-34(a).

[37] HRS § 269-2(a).

[38] HRS § 269-16(a).

[39] Section 2.3.(g)(2), General Order No. 7, as amended by Decision and Order No. 21002, filed in Dkt No. 03-0257, on May 27, 2004; HRS § 269-27.2; and HRS § 269-16.22.

[40] Section 2.3.(g)(2), General Order No. 7, as amended by Decision and Order No. 21002, filed in Dkt No. 03-0257, on May 27, 2004.

[41] *See* Order No. 34525, filed in Dkt No. 03-0257, on May 3, 2017 at 12 ("In general, this commission's analysis of capital expenditure applications involves a review of whether the project and its costs are reasonable and consistent with the public interest, among other factors."). (

[42] *Ibid*.

[43] *See* HRS §§ 269-17 through -19.

bonds, notes and other evidence of indebtedness.[44] The PUC assesses if the request and the terms and conditions of the proposed transaction are in the public interest and is reasonable.[45]

3.2.1.4 Resource planning

The electric utilities were previously required to file an integrated resource plan ("IRP") to the Hawaii PUC every three years[46] The goal of the IRP was to "develop an Action Plan that governs how the utility will meet energy objectives and customer energy needs consistent with state energy policies and goals, while providing safe and reliable utility service at reasonable cost, through the development of Resource Plans and Scenarios of possible futures that provide a broader long-term perspective."[47] In April 2014, the Commission rejected the HECO Companies' IRP Report and suspended the IRP planning cycle.[48]

In August 2014, the Hawaii PUC opened the Docket No. 2014-0183 to consolidate the review of the Power Supply Improvement Plans ("PSIP") filed by the HECO Companies.[49] The PUC stated that "the PSIPs are to include actionable strategies and implementation plans to expeditiously retire older, less-efficient fossil generation, reduce must-run generation, increase generation flexibility, and adopt new technologies such as demand response and energy storage for ancillary services, and institute operational practice changes, as appropriate, to enable integration of a diverse portfolio of additional low cost renewable energy resources, reduction of energy costs and improvements in generation operational efficiencies."[50] On November 4, 2015, the PUC rejected PSIPs filed by the HECO Companies on August 26, 2014, as the PUC identified eight observations and concerns.[51] Based on the guidance from the PUC, the HECO Companies revised the PSIPs and filed their most recent PSIP Update Report on December 23, 2016.[52] This PSIP Update Report was accepted, subject to certain conditions, by the PUC.[53] The PUC also directed the HECO Companies to file a report that "details the Companies' planning approach and

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[44] HRS § 269 -19.

[45] *Jones v. Hawaiian Electric Co.*, 64 Haw. at 298, 639 P.2d at 1111 (citing *In re Honolulu Rapid Transit Co., Ltd.*, 54 Haw. 402, 409, 507 P.2d 755, 759 (1973)).

[46] Decision and Order "*A Framework for Integrated Resource Planning*, " filed in Dkt No. 2009-0108, on March 14, 2011, Exhibit A at 11.

[47] *Ibid* at 2.

[48] Order No. 32052, filed in Dkt No. 2012-0036, on April 28, 2014, at 80.

[49] Order No. 32257, filed in Dkt No. 2014-0183, on August 27, 2014.

[50] *Ibid.* (quoting Order No. 32052, filed in Docket No. 2014-0183, on April 28, 2014, at *72 - 73*.)..

[51] Order No. 33320, filed in Dkt No. 2014-0183 on November 4, 2015.

[52] *Ibid.*; HECO's PSIPs Update Report, Book 1 through 4, filed in Dkt No. 2014-0913, on December 23, 2016 ("PSIP Update Report").

[53] Order No. 34696, filed in Docket No. 2014-0183, on July 14, 2017.

schedule for the next round of integrated planning." The HECO Companies proposed an Integrated Grid Planning process that included an ambitious leap forward from traditional system planning, i.e. merging three separate planning processes - generation, transmission, and distribution - while simultaneously integrating solution procurement into this merged process.[54]

3.2.1.5 Reliability and Service Quality

As mentioned earlier, the State is not under NERC oversight and therefore, some of the responsibilities that are normally covered by NERC in the mainland are the responsibility of the PUC in Hawaii. These include setting out the reliability standards that the electric utilities need to comply with, which are set forth in HRS Chapter 269, General Order 7 - *Standards for Electric Utility Service in the State of Hawaii,* HAR 6-73, and various orders issued by the PUC from time to time, such as Order No. 30371 in Docket No. 2011-0206, which investigated the implementation of reliability standards for the HECO Companies.

> Paragraph 5.3a. of General Order No. 7 states that "the generation capacity of the utility's plant, supplemented by electric power regularly available from other sources, must be sufficiently large to meet all reasonably expectable demands for service and provide a reasonable reserve for emergencies. A statement shall be filed annually with the Commission within 30 days after the close of the year indicating the adequacy of such capacity and the method used to determine the required reserve capacity which forms the basis for future requirements in generation, transmission, and distribution plant expansion programs."
>
> Source: General Order No. 7, as amended by Decision and Order No. 21002, filed in Dkt No. 03-0257, on May 27, 2004; HRS § 269-27.2; and HRS § 269-16.22.at 18.

As required in the Order No. 30371, the HECO Companies should provide monthly reliability reports, including system frequency control performance, significant system events, and curtailment of non-dispatchable renewable resources during the month to the PUC.[55] Some reliability standards do not have any associated rewards or penalties and therefore, are tracking-only metrics, shown in Figure 5.[56]

The System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI") have penalties if the prescribed performance target is not met. More specifically, for SAIFI, the performance target is 1.116 interruptions per customer during a one-year period.[57] Penalties are imposed when utilities have greater than 1.206 interruptions per

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[54] Order No. 35569. Docket No. 2018-0165. Filed on July 12, 2018.

[55] *Order No. 30371 Relating to Various Matters in RSWG Process*, filed in Docket No. 2011-0206, on May 4, 2012 at 17 - 19.

[56] Hawaii PUC, *Service Quality Reliability Annual Reports.* Website, available at. <http://puc.hawaii.gov/reports/energy-reports/service-quality-reliability-annual-reports/>. (Last Visited February 16, 2018).

[57] Order 35411, at 44 -45.

customer.[58] The maximum penalty amount is currently $2,039,094, which is determined by calculating 0.20% of Common Equity Share of Approved Average Test Year Rate Base determined in the most recent interim or final order in a general rate case for each HECO Company[59]

Figure 5. Reliability standards and quality of service tracked by the utilities

Metric		Description
ASAI	Average Service Availability Index	Overall availability of electrical service
SAIFI	System Average Interruption Frequency Index	The frequency or number of times a company's customers experience an outage during the year
CAIDI	Customer Average Interruption Duration Index	The average length of time an interrupted customer is out of power
SAIDI	System Average Interruption Duration Index	The average length of time the company's customers are out of power during the year

Source: HECO Annual Service Reliability Reports, last filed August 30, 2017.

Likewise, the maximum penalty for not achieving the performance target for SAIDI is currently at $2,039,094, which is determined by calculating 0.20% of Common Equity Share of Approved Average Test Year Rate Base determined in the most recent interim or final order in a general rate case for each HECO company.[60] The performance target is at 99.03 minutes per outage. Penalties are enforced if outages are longer than 108.10 minutes per outage.[61]

In addition to reliability, the PUC also monitors the utilities' service quality. More specifically, the utilities need to track how fast it answers calls from customers.[62] The Call Center Performance Incentive Mechanism ("PIM") measures the performance of the utility call center in terms of the percentage of calls answered within 30 seconds.[63] There is a reward and penalty for meeting and missing the target.[64] Currently, the maximum reward and penalty is ±$815,638, which is

[58] *Ibid*.

[59] *Ibid*.

[60] *Ibid*. at 45.

[61] *Ibid*.

[62] *Ibid* at 46.

[63] *Ibid*.

[64] *Ibid*.

determined by calculating 0.08% of the most recent interim or final order in a general rate case's Common Equity Share of Approved Average Test Year Rate Base.[65]

3.2.1.6 Interconnection

The PUC also provides guidelines with regards to the interconnection standards and requirements. For example, in 2011, the PUC issued a decision and order to improve Hawaii's interconnection standards for connections to customer's premises, primarily interconnection of distributed generating facilities operating in parallel with HECO Companies' electric systems, which approved a supplemental review process and other measures to limit the scope of systems that must conduct an Interconnection Requirements Study ("IRS").[66] This was subsequently amended in Decision and Order No. 33258, filed in Dkt No. 2014-0192, on October 12, 2015. According to the HECO Companies' Rule 14H, "the technical interconnection standards are based on the requirements of IEEE 1547-2003 *Standard for Interconnecting Distributed Resources with Electric Power Systems*."[67]

3.2.1.7 Investigative proceedings

The PUC has the power to initiate investigatory proceedings to examine different issues.[68] Examples of these energy policy issues include, but are not limited to, a renewable energy infrastructure program,[69] on-bill financing programs,[70] community-based renewable energy,[71] distributed energy resources,[72] and performance-based regulations.[73] In some instances, the Commission will open an investigatory docket to comply with a legislative mandate. An example of this is the community-based renewable energy proceeding.[74] The PUC may also hold conferences and workshops to discuss various matters and to share information among stakeholders.

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[65] *Ibid*.

[66] Decision and Order No. 30027, filed in Dkt No. 2010-0015, on December 20, 2011.

[67] HECO Companies' *Rule 14 H,* at Superseding Tariff Sheet No. 34B-2, effective February 20, 2018.

[68] HRS § 269-7.

[69] Order No. 23913 *Instituting a Proceeding to Examine HECO Companies' Proposal for a Renewable Energy Infrastructure Program*, filed in Dkt No 2007-0416, on December 20, 2007.

[70] *See* Order No. 32114 *Re Establish and Implement On-Bill Financing Program*, filed in Dkt No. 2014-0129, on June 3, 2014.

[71] *See* Order No. 33358, filed in Dkt No. 2015-0389, on November 27, 2015.

[72] *See* Order No. 32269 *Instituting a Proceeding to Investigate Distributed Energy Resource Policies,* filed in Dkt No. 2014-0192, on August 21, 2014.

[73] *See* Order No. 34511 *Institution a Proceeding to Investigate Performance-Based Regulations*, filed in Dkt No. 2018-0088, on April 18, 2018.

[74] *See* Order No. 33358, filed in Dkt No. 2015-0389, on November 27, 2015.

3.2.1.8 Monitoring

The electric utilities are also required to submit various annual reports to the PUC for monitoring purposes. These reports include the following (not exhaustive list):

- information on the total rated generating capacity produced by eligible customer-generators that are customers of that utility in the utility's service area;[75]
- performance metrics (to be posted on the utilities' website with a link to the metrics on the website's homepage);[76]
- financial report with certification that such report conforms with the applicable uniform system of accounts adopted by the commission;[77]
- all accidents caused by or occurring in connection with its operations and service;[78]
- energy resource by generation category to its existing and new retail electricity customers for the prior calendar year;[79] and
- the average retail price of electricity (per kilowatt-hour) for each rate class of service for the prior calendar year.[80]

3.2.2 Hawaii State Legislature

The Hawaii State Legislature, co-equal to the executive and judicial branches of Hawaii's state government, is responsible for making laws. The House Committee on Energy & Environmental Protection focuses on programs relating to energy resources and the development of renewable and alternative energy resources, energy conservation, environmental quality control and

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[75] HRS §269-103. Generating Capacity.

[76] *Key Performance Metrics*, HECO Companies' Website, available at https://www.hawaiianelectric.com/about-us/key-performance-metrics (Last Visited May 14, 2018).

[77] *Annual Financial Reports (AFR) for Electric Utilities*, State of Hawaii Public Utilities Commission Website, available at http://puc.hawaii.gov/reports/energy-reports/annual-financial-reports-electric-utilities/ (Last Visited May 14, 2018).

[78] *See* Hawaiian Electric Companies Annual Service Reliability Reports, available at http://puc.hawaii.gov/reports/energy-reports/service-quality-reliability-annual-reports/ (Last Visited May 14, 2018).

[79] *See* Renewable Portfolio Standard Status (RPS) Annual Reports (Electric, Docket 2007-0008), available at http://puc.hawaii.gov/reports/energy-reports/renewable-portfolio-standards-rps-annual-reports/ (Last Visited on May 14, 2018).

[80] Average Price of Electricity, available at https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/average-price-of-electricity (Last Visited May 14, 2018).

protection, and environmental health, and other pertinent matters referred to it by the House.[81] Likewise, the Senate has the Senate Committee on Transportation and Energy, which focuses on programs relating to air, water, and surface transportation, and transit-oriented development as it relates to transportation projects; and energy resources, including the development of alternative energy resources.[82] In addition, the Senate Committee on Commerce, Consumer Protection, and Health oversees regulations relating to public utilities and other regulated business, and the House Committee of Consumer Protection oversees programs relating to consumer protection and the regulation of utilities as well.[83]

3.2.3 Consumer Advocate

The Consumer Advocate is statutorily mandated to represent, protect, and advance the interests of all consumers of utility services.[84] By statute, the Consumer Advocate is a party to all PUC proceedings,[85] and as such reviews filings from utilities, may request information from public utilities that will be helpful to perform its duties, and represents consumer interests before the PUC.

3.3 Rulemaking process

Under Hawaii law, a rule is defined as follows:

> "Rule" means each agency statement of general or particular applicability and future effect that implements, interprets, or prescribes law or policy, or describes the organization, procedure, or practice requirements of any agency. The term does not include regulations concerning only the internal management of an agency and not affecting private rights of or procedures available to the public, nor does the term include declaratory rulings issued pursuant to section 91-8, nor intra-agency memoranda.

With respect to the PUC, the rulemaking process usually involves the PUC, on its own motion, proposing a draft of rules.[86] This is then followed by a public hearing, a period of ten (10) days following the hearing for all interested persons to submit written comments, and final action by

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[81] *House Committee on Energy & Environmental Protection*. Hawaii State Legislature Website, Available at https://www.capitol.hawaii.gov/committeepage.aspx?comm=EEP (Last Visited April 19, 2018).

[82] *Senate Committee on Transportation and Energy,* Hawaii State Legislature Website, Available at https://www.capitol.hawaii.gov/committeepage.aspx?comm=TRE&year=2018 (Last Visited May 14, 2018).

[83] *House Committee on Consumer Protection & Commerce*, Hawaii State Legislature Website, Available at https://www.capitol.hawaii.gov/committeepage.aspx?comm=CPC&year=2018 (Last Visited May 14, 2018).

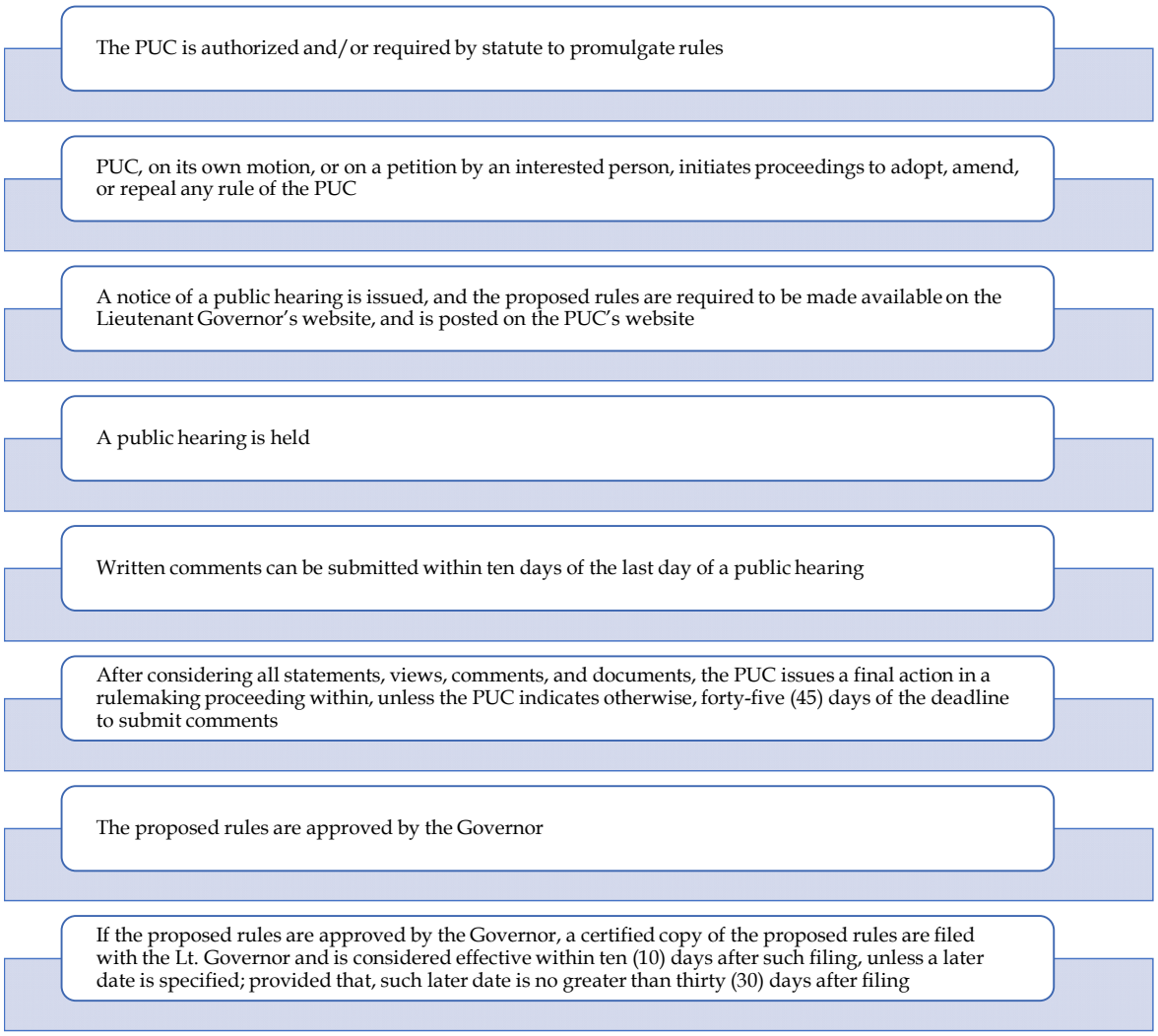
[84] *See* HRS § 269-51.

[85] *See* HRS § 269-51.

[86] HAR § 16-601-146; HRS § 269-6.

the PUC within forty-five (45) days of the deadline to submit comments, unless a different date is set by the PUC.[87]

Figure 6. PUC's rulemaking process



Source: HRS §§ 91-1 to -2; HRS § 91-6; HRS §§ 269-6, -6.5(b), -15(b)(4), -44, -96(b) and (c), -102(a) and (b), -111(c), -121(a) and (b),-123(a) and (b), -142(a), -144(c), 145(a), and -146(a).HAR § 16-601-146(a); HAR §§ 16-601-146 to -154

The proposed rules are then subject to the Governor's approval.[88] Upon approval by the Governor, certified copies of the rules are filed with the Lieutenant Governor's office and such

[87] HRS § 91-3; HAR §§ 16-601-150 to -154.

[88] HRS § 91-3; HAR §§ 16-601-146 to -154

rule becomes effective within ten (10) days of this filing, unless another date is specified[89] In addition to the PUC, any interested person may petition the PUC to adopt, amend, or repeal any rule of the PUC.[90] The PUC shall, within thirty days after the filing of a petition for rulemaking, either deny the petition or initiate proceedings.[91] If the PUC finds that emergency rulemaking is required, it may modify the procedures enumerated above.[92]

3.4 Ratemaking

Pursuant to HRS § 269-16, all rates, schedules, rules, and practices made or charged by public utilities are required to be filed with the PUC.[93] For any increase in rates, the PUC must hold a contested case hearing preceded by a public hearing at which consumers may present testimony concerning the increase.[94] Electricity rates in Hawaii are generally determined using the cost of service ("COS") approach. Due to differences in ownership structure, the approaches used by the HECO Companies and KIUC differ and are discussed in further detail below. The approach used for the HECO Companies has been modified from traditional COS ratemaking to incorporate certain elements of PBR. Each of the utilities also utilizes certain automatic rate adjustment clauses to automatically adjust for variability in fuel or purchased power costs between rate cases.[95]

3.4.1 Ratemaking Process

The current ratemaking process generally begins when a utility files notice of its intent to file for a general rate increase at least two months prior to filing a rate application.[96] Generally, utilities request rate adjustments when costs have increased, and major investments have been or are being made and revenues collected no longer generate a sufficient rate of return sufficient in magnitude to justify the time and expense of applying for a rate increase, or when required by

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[89] Provided that such other date is not more than thirty (30) days after filing. HRS § 91-4; HAR § 16-601-154.

[90] HRS § 91-6; HAR § 16-601-146(b).

[91] HRS § 91-6; HAR § 16-601-148(a); *See also* HAR §§ 16-601-146 to -155. An example of this process is currently occurring with the PUC moving HAR Chapters 16-601, 6-63, 6-65, and 6-68, to Chapter 16-601, 16-603, 16-605, and 16-608, respectively. *See Proposed Rule Making*, PUC Website, available at http://puc.hawaii.gov/about/statutes-rules-orders/proposed-rulemaking/ (Last visited May 15, 2018).

[92] HRS § 91-3; HAR § 16-601-155.

[93] HRS § 269-16(a).

[94] HRS § 269-16(b).

[95] *See* HRS § 269-16(d), (g); HAR § 6-60-6.

[96] HAR § 16-601-85(a).

the PUC. For example, KIUC has not filed a rate case since 2010.[97] In contrast, each of the HECO Companies is required to file a rate case every three years.[98]

The application describing the proposed change in rates is then submitted to the PUC along with written direct testimony justifying the requested increase as well as supporting exhibits and workpapers.[99] The Commission must make a determination as to whether the application is complete under HRS Chapter 269, as the deadline for the Commission to complete its deliberations and issue its decision begins only after a completed application is filed and served on the Consumer Advocate.[100] The Consumer Advocate will have twenty-one days to object to the sufficiency of the application.[101] Accordingly, the Consumer Advocate will typically file a statement of position regarding the completeness of the application and the Commission will issue an order establishing the date the completed application was filed.[102]

As required by statute, the PUC will hold a public hearing for each rate case.[103] Interested persons can file motions seeking to intervene or participate in the docket, which must be filed no later than ten days after the last public hearing.[104] The PUC, the Consumer Advocate, and any admitted intervenors or participants,[105] may submit information requests to build the record in the proceeding, as may be allowed and subject to any conditions and limitations that may be established by the PUC.[106] Typically, the utility, the Consumer Advocate, and any parties granted full intervenor status, may negotiate and file a stipulation or partial stipulation for the commission to review if they have reached an agreement on certain issues.[107] Additional

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[97] *See* Docket No. 2009-0050, Order Closing the Docket, issued Oct. 12, 2010, at 1-2.

[98] *See* Docket No. 2008-0274, Final Decision and Order, issued Aug. 31, 2010, at 129 ("So that the commission and the Consumer Advocate have a regular opportunity to evaluate decoupling and re-calibrate RAM inputs using commission-approved values, the HECO Companies shall file staggered rate cases every three years.").

[99] *See* HAR § 16-601-87 (applies to utilities with Annual Gross Operating Revenues of $2,000,000 or more).

[100] HRS § 269-16(d); HAR § 16-601-86, -87.

[101] HRS § 269-16(d).

[102] *See, e.g.*, Docket No. 2016-0328, Division of Consumer Advocacy's Statement of Position Regarding Completeness of Application, filed Jan. 5, 2018; Docket No. 2016-0328, Order No. 34664, issued June 28, 2017 (certifying completeness of the application).

[103] HRS § 269-16(b).

[104] HAR 16-601-57(1).

[105] "Intervenor" means a person who moves to intervene in a contested case and is admitted as a party; "participant" means a person allowed to participate in a proceeding pursuant to section 16-601-56. See HAR 16-601.

[106] The scope and schedule of information requests are governed in dockets by procedural orders and schedules issued by the PUC.

[107] *See, e.g.*, Docket No. 2016-0328, Parties' Stipulated Settlement Letter, filed Nov. 15, 2017.

testimony and rebuttal testimony may be taken and evidentiary hearings may be held on any unsettled issues.[108]

Generally, the PUC reviews and determines the total annual revenues required by the utilities to cover its projected expenses and provide it with an opportunity to earn a fair return on its investments. The PUC is required by statute to issue its decision as expeditiously as possible, and within nine months from the date the public utility filed its completed application.[109] If the PUC is unable to issue a final decision within the prescribed time period, it must issue an interim decision allowing an increase in rates, fares, and charges, if any, to which the PUC believes the utility is probably entitled.[110] Subsequently, the PUC will have to issue a final decision and order that either adopts the interim decision and order or may reflect modifications from the interim decision and order.

3.4.2 Ratemaking for the HECO Companies

For the investor-owned HECO Companies, as discussed below, rates are determined using a rate of return COS approach, with some variations that includes some components associated with PBR, namely the use of: multi-year rate plans, earnings sharing mechanisms ("ESM") between the utility and the customers for the HECO Companies, decoupling using a revenue adjustment mechanisms ("RAM") subject to a revenue cap and using revenue balancing accounts ("RBA"), and recently performance incentive mechanisms ("PIM"). In addition, the HECO Companies' rates include a new Energy Cost Recovery Clause,[111] which shall be consistent with the terms of fuel contracts, distributed generation contracts, and purchased energy contracts. Changes to the Energy Cost Recovery Clause may be proposed by application to the PUC.[112]

3.4.2.1 Calculating revenue requirements

Under a traditional COS approach, revenue requirements identify the expected amount of revenue the utility requires to cover its COS for a given forecasted twelve month period (referred to as a "test year").[113] As shown in the formula below (and discussed in detail in Task 1.6.1), the revenue requirements are comprised of the rate base multiplied by the allowed rate of return plus

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[108] *See, e.g.*, Docket No. 2016-0328, Procedural Order No. 34721, issued July 28, 2017, at 9-11 (procedural schedule); Docket No. 2016-0328, Order No. 35219 *Amending Procedural Order No. 34721*, issued July 28, 2017, at 7-8,13-14 (revised procedural schedule reflecting settlement and interim order).

[109] HRS § 269-16(d).

[110] HRS § 269-16(d).

[111] As approved by the PUC in the final decision and order under Docket 2016-0328, the Energy Cost Recovery Clause replaced the original Energy Cost Adjustment Clause ("ECAC").

[112] Order No.35927. Docket No. 2016-0328. Page 14.

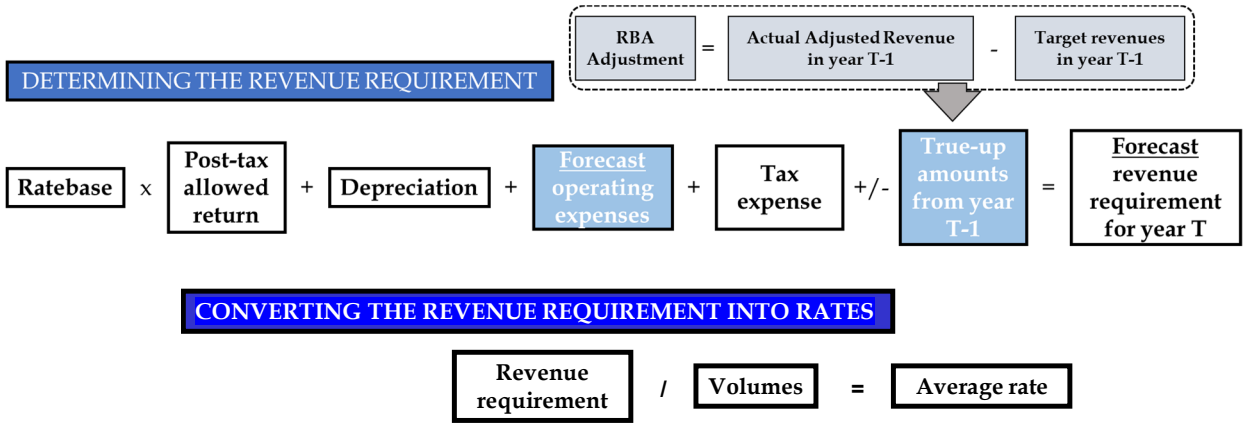
[113] *See,* HAR § 16-601-87(4).

the sum of depreciation and amortization expenses, operating expenses, and tax expenses.[114] Under the COS approach, the operating and other expenses as well as the cost of power are costs that are passed through to customers and do not provide a "return on investment" to the utilities. On the other hand, generally, the rate base (which includes the investments in net utility plant and other items such as regulatory assets and working capital) is multiplied by the PUC-approved rate of return to determine the revenue required. The HECO Companies estimate the rates of return they propose for PUC approval based on "multiple analytical techniques including the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), and the Bond Yield Plus Risk Premium approach."[115]

As shown in the revenue requirement formula below, the utility's ability to increase earnings is tied to increases in the rate base and higher approved levels of rates of return. As a result, the traditional COS approach may create an incentive for the utility to spend more on capital expenditures to increase the overall associated returns it receives on investments. This is one of the reasons given for the recent passage of the Hawaii Ratepayer Protection Act.[116] See Section 3.5 for further discussion on this new law and the PUC's PBR proceeding related to the law's objectives.

$$\begin{aligned} &Traditional\ COS\ Revenue\ Requirements \\ &= (Rate\ Base * Approved\ Rate\ of\ Redurn) + Operating\ Expenses \\ &+ Depreciation\ and\ Amortization\ Expenses + Tax\ Expenses \end{aligned}$$

Figure 7. Determining the revenue requirements and rates



Note: RBA = Revenue Balancing Account

[114] *See, generally*, Docket No. 2016-0328.

[115] *See, e.g.*, Docket No. 2016-0328, Direct Testimonies and Exhibits, Book 9, HECO T-28 Executive Summary, filed December 16, 2016.

[116] *See* 2018 Haw. Sess. Laws Act 5 § 1.

3.4.2.2 Hawaii-specific performance-based regulation applicable to the HECO Companies

The current regulatory framework also has some components associated with PBR. These include a fixed three-year cycle for general rate cases, the decoupling mechanism, an ESM, an interim-period revenue adjustment mechanism which includes a revenue cap, and performance incentive mechanisms ("PIMs"). The decoupling mechanism consists of a Revenue Balancing Account ("RBA") and the Revenue Adjustment Mechanism ("RAM").

- **Multi-Year Rate Plan ("MRP")**: MRPs permit utilities to operate for several years (typically three to five years) without a general rate case.[117] The HECO Companies are on fixed three-year general rate case cycles.[118]

- **RBA Decoupling Mechanism**: Revenue decoupling "de-links" the utility's revenues from the volume of electricity sales. In other words, decoupling aims to eliminate the financial detriment caused by reduced electricity sales and thus the utilities' disincentive to pursue energy efficiency measures and utilize more distributed energy. RBA is "the sales decoupling component, which is designed to break the link between the HECO Companies' sales and their total electric revenues by setting the target revenues to the most recent authorized revenue level approved in each utility's most recent rate case."[119] Under the RBA, the HECO Companies recover PUC-approved "Target Revenues" (and no more or less). Base rates are adjusted using a per kWh rate adjustment (the "RBA Rate Adjustment"), which is calculated by dividing a sum which includes the calendar year-end balance in the RBA balance as well as certain adjustments included in the RAM and PIM provisions by the Company's forecast of MWh sales over the RBA Rate Adjustment recovery period.[120]

- **RAM Decoupling Mechanism**: The RAM is designed to "compensate [the] HECO Companies for increases in utility costs and infrastructure investment between rate cases through formula-driven estimates."[121] Because of the RAM, the HECO Companies do not have to wait until the next general rate case to recover the approved costs and infrastructure investments and instead may do so between rate cases. Items that are subject to yearly update and escalation through the RAM include labor and non-labor O&M and payroll tax expenses, return on incremental investment, updated depreciation

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[117] Order No. 35411, at 16.

[118] Order No. 35411, at 41.

[119] Docket No. 2013-0141, Order No. 32735 Modifying Decoupling Mechanisms and Establishing Briefing Schedule, issued March 31, 2015, at 9-10.

[120] *See, e.g.*, Tariff Applicable to Electric Service of Hawaiian Electric Company, Inc., Revenue Balancing Account ("RBA") Provision, *available at* https://www.hawaiianelectric.com/Documents/my_account/rates/hawaiian_electric_rates/heco_rates_rba.pdf .

[121] *Ibid.*

and amortization expenses, and changes in costs due to significant changes in tax laws or regulations.[122]

- **RAM Revenue Cap**: In the event that the RAM Revenue Adjustment exceeds the Target Revenue for the rate case test year, increased by the compound Gross Domestic Product Price Indicator ("GDPPI") for each year following the test year, the RAM Revenue Adjustment will be capped, and excess expenses will not be recoverable under the RAM Revenue Adjustment.[123]

- **Earnings Sharing Mechanism ("ESM")**: ESMs are generally designed so that the extraordinary earnings (or losses in some jurisdictions) are shared between the utility and its customers rather than retained (or absorbed) entirely by the utility. In the case of the HECO Companies, the ESM is asymmetrical where only excess earnings (*i.e.,* where utility earnings are greater than the authorized return on equity ("ROE")) are shared with the customers. This means that where there are no excess earnings (*i.e.*, earnings are at or below the authorized ROE), any lower than expected earnings will be fully absorbed by the utility's shareholders and not by its ratepayers. In other words, if the utilities' ROE is at or below the authorized ROE, any earnings will be retained entirely by shareholders. The Table below shows the ROE at or below the authorized ROE and the sharing:[124]

ROE at or below the Authorized ROE	Retained entirely by shareholders – no customer credits
First 100 basis points (1%) over Authorized ROE	25% share credit to customers
Next 200 basis points (2%) over Authorized ROE	50% share credit to customers
All ROE exceeding 300 basis points (3%) of Authorized ROE	90% share credit to customers

Source: Order No. 35411, at 43.

- **Performance Incentive Mechanisms ("PIMs"):** PIMs consist of metrics, targets, and incentives used to address performance and provide regulatory guidance and incentives regarding the implementation of new technologies and practices.[125]

[122] Order No. 35411, at 43.

[123] *See,* Order No. 35411, at 42-43.

[124] Order No. 35411, at 43.

[125] Order No. 35411, at 17.

- **Service Quality (Traditional) PIMs:** Currently, the HECO Companies' rates are based in part on penalty PIMs based on achieving service outage frequency ("SAIDI") and duration ("SAIDI") metrics as well as a PIM for call center performance which provides either a penalty or a reward.[126]

- **Targeted Energy Policy PIMs:** Recently, the PUC has approved incentive PIMs related to the HECO Companies' achievement of cost savings in renewable generation procurement as well as the implementation of the HECO Companies' demand response portfolio.[127]

As noted below, these PBR elements are incorporated into the HECO Companies' rates using the RBA Rate Adjustment.[128] This is independent of the establishment of the HECO Companies' base rates for each rate case test year based on traditional COS methods.

3.4.2.3 Calculating Rates and Rate Design

After calculating the revenue requirements, the revenue requirements are then allocated to various customer classes as a function of cost to provide service to each customer class to determine and design the rates to be charged to the various classes of customers. The HECO Companies use a cost of service study to determine the cost responsibility assigned to different customer classes for ratemaking purposes.[129] All of the costs incurred in providing electric service to customers are incorporated in the embedded cost of service study, including the estimates of operation and expenses, depreciation expenses, taxes, plant costs, and return on capital.[130] Three major steps are involved in the embedded cost of service study methodology, as shown in Figure 8.[131]

As discussed in Task 1.6.4, the HECO Companies calculate the rates for Residential and Small Power Use Business mainly based on energy consumption. The rates that have been established for the customer classes vary according to customer class and level of consumption and may include various additional charges and adjustments. For example, there is a customer charge ($ per customer per month) and a Green Infrastructure Fee ($ per customer per month) added to all

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[126] Order No. 35411, at 44-46.

[127] Order No. 35411, at 46-47.

[128] *See*, Tariff Applicable to Electric Service of Hawaiian Electric Company, Inc., Revenue Balancing Account ("RBA") Provision, *available at* https://www.hawaiianelectric.com/Documents/my_account/rates/hawaiian_electric_rates/heco_rates_rba.pdf

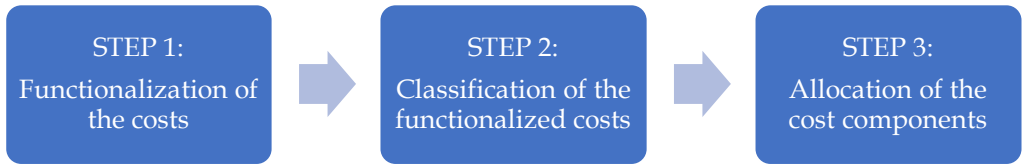
[129] For more information on this, please refer to the Working Paper for Task 1.6.4.

[130] *Ibid.*

[131] *Ibid*, at 10.

bills.[132] As additional examples, rates for Medium Power Use Business, Large Power Use Business, and Large Power Use Business, Directly Served include a demand charge ($ per kW), as well.[133] The HECO Companies also provide an optional Time-of-Use ("TOU") pilot rate program for Schedule R, G, J, and P rate classes.[134]

Figure 8. Key steps in the cost of service study methodology



In addition to the computation of base rates described above, amounts charged to the HECO Companies' customers are adjusted for changes in short-term fuel prices and purchased energy expenses, as well as changes in certain non-energy costs associated with purchased power using the ECAC and PPAC.[135]

3.4.3 Ratemaking for KIUC

For member-owned cooperative KIUC (*i.e.*, not an investor-owned, for-profit public utility), rates are determined using a debt service coverage COS approach known as Times Interest Earned Ratio ("TIER"). In addition, KIUC's rates include an Energy Rate Adjustment Clause ("ERAC"), which recovers certain variable fuel and purchased energy costs. These rate design elements will be discussed in greater detail below.

3.4.3.1 Calculating revenue requirements

As discussed in Task 1.4.2., KIUC's revenue requirement calculation is based on somewhat different principles than those used for the HECO Companies. While maintaining financial integrity is important to KIUC, its revenue requirement target is mainly designed to meet its debt obligations rather than to provide a reasonable rate of return for shareholders of an investor-owned public utility. KIUC's equity is held primarily by its customer-members, who make contributions for service and not with a set expectation of receiving a return. Therefore, the

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[132] *See, e.g.*, Tariff Applicable to Electric Service of Hawaiian Electric Company, Inc., Schedules R and G, *available at* https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/hawaiian-electric-rates.

[133] *See, e.g.*, Tariff Applicable to Electric Service of Hawaiian Electric Company, Inc., Schedules J and P, *available at* https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/hawaiian-electric-rates.

[134] *See, e.g.*, Tariff Applicable to Electric Service of Hawaiian Electric Company, Inc., Schedules TOU-R and TOU-J, *available at* https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/hawaiian-electric-rates. Participation is voluntary. Currently, only HELCO and MECO (not HECO) have Time-of-Use Schedule TOU-P.

[135] Order No. 35411, at 47-48.

revenue requirements of a co-op are set using a Times Interest Earned Ratio ("TIER") level, as discussed in Task 1.4.2. TIER is a solvency ratio that measures a co-op's ability to meet its long-term debt obligations. It is calculated by dividing the sum of net income and total interest expense by total interest expense. Net income is essentially the operating margin in the case of KIUC. The formula for the TIER level is:

$$TIER = (Earnings\ Before\ Interest\ and\ Taxes)/(Interest\ Expense)$$

The ratio measures how many times KIUC can cover its interest expenses from its pre-tax earnings. Although the United States Department of Agriculture's ("USDA") Rural Utilities Service ("RUS") loan agreements require a minimum TIER of 1.25[136] for distribution utilities, the PUC has set the current regulated TIER level for KIUC at 2.27.[137] The operating revenue remaining after operating expenses and debt service is a co-op's net margin for that year. The revenue requirement for KIUC is set so that it earns a sufficient margin to achieve the target TIER level. This margin helps KIUC to maintain financial stability and make the necessary investments on the grid.

From the formula for TIER level, the following can be inferred:

$$TIER = (Interest\ Expense + Margins)/(Interest\ Expense)$$

$$TIER = (Revenues - Operating\ Expenses)/(Interest\ Expense)$$

$$Revenues - Operating\ Expenses = Interest\ Expense * TIER$$

$$Revenue\ Requirement = Interest\ Expense * TIER + Operating\ Expenses$$

KIUC's revenue requirements comprise of interest expense, TIER level, and operating costs:

1. Interest expense

   a) Capital structure helps to determine how much debt the co-op can carry. A higher debt-capital ratio increases the interest expense and thus the revenue requirements. This is the opposite for an IOU, which can increase leverage to lower the WACC.

   b) Interest rates are lower for co-ops than IOUs. Co-ops have access to low-cost debt from public and private sources that IOUs do not, enabling them to lower their financing cost.

2. TIER level – set by the regulator.

3. Operating costs – generally the same as for IOU, with the exception that tax expenses are lower for co-ops because they are exempt from federal income taxes.

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[136] *See* Docket No. 2009-0050, Application, Volume 1, filed June 30, 2009, at 10.

[137] Docket No. 2009-0050, Decision and Order, issued September 9, 2010, at 1-2.

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3.4.3.2 Calculating Rates and Rate Design

After calculating the revenue requirements based on the approved TIER level, revenue requirements are then allocated to customer classes as a function of cost to provide service to each customer class in a manner similar to the COS method used by the HECO Companies. Like the HECO Companies, KIUC also uses the embedded cost approach for the cost of service analysis, including the functionalization, classification, and allocation of revenue requirement.[138]

KIUC calculates rates based on customer charges and energy consumption for Residential and Small Commercial, but also includes a demand charge for Large Commercial and Large Power (Primary and Secondary).[139] Also, KIUC also has a pilot TOU rate program for Residential and limited to approximately 300 residential customers who are duly selected to participate in the program.[140] KIUC's rates are then adjusted pursuant to an Energy Rate Adjustment Clause ("ERAC") which accounts for changes in the price of fuel and purchased energy as compared to the 2010 test year.[141]

3.5 Future of Hawaii-specific performance-based regulation

On April 24, 2018, the Governor of Hawaii signed the Hawaii Ratepayer Protection Act.[142] This new law aims to address concerns that the current traditional regulatory approach may not provide appropriate incentives to utilities to meet the challenges of a renewable and distributed energy future.[143] The law directs the PUC to create "performance incentives and penalty mechanisms that … break the direct link between allowed revenues and investment levels" by January 1, 2020.[144] The Hawaii Ratepayer Protection Act directs the PUC to consider economic incentives, penalties, and cost-recovery rules that promote affordability of rates, electric reliability, customer choice and satisfaction, data transparency, rapid integration of renewables, and timely execution of competitive procurement and other business processes.[145] Among the reasons to explore and implement PBR mechanisms are to align the regulatory framework and the utilities' financial interests with the public interest.[146]

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[138] Docket No. 2009-0050, Application, Volume 2, filed June 30, 2009, Exhibit KIUC 10-T-600, at 4.

[139] *See* KIUC Tariff No. 1, Schedules "D", "G", "J", "L", and "P", *available at* http://website.kiuc.coop/content/tariffs.

[140] *See* KIUC Tariff No. 1, Schedule "TOU-S", *available at* http://website.kiuc.coop/content/tariffs.

[141] *See, e.g.* KIUC Tariff No. 1, Schedules "D", "J", and "P", *available at* http://website.kiuc.coop/content/tariffs.

[142] Gov. Msg. No. 1105 (April 24, 2018); *see also* 2018 Haw. Sess. Laws Act 5.

[143] *Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5, § 1.

[144] *Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5, § 3.

[145] *Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5.

[146] Order No. 35411, at 51; *see also Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5, § 1.

Related to the objectives of the Hawaii Ratepayer Protection Act, the PUC issued Order No. 35411, *Instituting a Proceeding to Investigate Performance-Based Regulation*, on April 18, 2018, opening Docket No. 2018-0088, a proceeding to investigate the PBR for the HECO Companies ("PBR Docket").[147] The PUC intends for Docket No. 2018-0088 to be "a forum by which to evaluate the current regulatory environment; identify which elements, if any, may not adequately align with the public interest; and collaboratively develop modifications or new components to better align utility and customer interests."[148] The Commission aims to "(1) identify specific areas of utility performance that should be improved; (2) determine appropriate metrics for measuring successful outcomes in those areas; and (3) establish reasonable financial rewards and/or penalties that are sufficient to incent the utility to achieve those outcomes."[149]

According to Order No. 35411, PBR includes a "set of alternative frameworks and regulatory mechanisms intended to focus utilities on performance and desired outcomes as opposed to simply growth in capital investments or other determinants of utilities earnings" under traditional COS rate regulation.[150] PBR offers regulators a way to restructure utility financial incentives to achieve broad objectives such as incenting cost reduction and achievement of policy goals, improving unsatisfactory performance, integrating technological advances, and supporting customer choice.[151]

In Docket No. 2018-0088, the PUC stated that it is particularly interested in PBR mechanisms that result in:

- "Greater cost control and reduced rate volatility;
- Efficient investment and allocation of resources regardless of classification as capital or operating expenses;
- Fair distribution of risks between utilities and customers; and
- Fulfillment of state policy goals." [152]

[147] Order No. 35411.

[148] Order No. 35411, at 51.

[149] Order No. 35411, at 52.

[150] Order No. 35411, at 13.

[151] Order No. 35411, at 14.

[152] Order No. 35411, at 5.

PBR framework vs. Performance Incentive Mechanisms ("PIMs"), according to the PUC

"PBR frameworks constitute a wholesale change in the regulatory procedures and cost control incentive associated with the traditional ratemaking process by, among other things, allowing utilities to profit from realized cost efficiencies and establishing financial rewards or penalties based on utility performance according to specific incentive metrics."

"Standalone PIMs can provide financial rewards and/or penalties for utility performance according to specific metrics, without necessarily requiring a substantial change to other ratemaking procedures."

Source: Docket No. 2018-0088, Order No. 35411, issued April 18, 2018, at 37.

The proceeding will be implemented in two phases. During Phase 1, the current regulatory framework will be assessed and evaluated. Specific areas of utility performance that should be targeted for improvement and metrics for determining successful outcomes in those areas will be identified. [153] During Phase 2, the PUC will focus on refinements and modifications that can be made to the existing regulatory framework to incent the utility to achieve those outcomes. New PBR frameworks will be developed, including performance incentives, to increase the alignment between the utilities' interests and those of the customers. [154] The Commission expects Phase 1 to conclude in "approximately nine months" while Phase 2 will take approximately 12 months.[155]

As a member-owned cooperative electric utility, the Hawaii Ratepayer Protection Act does not apply to KIUC.[156] In addition, pursuant to Order No. 35411, KIUC is waived from involvement in Docket No. 2018-0088 because the method used by KIUC to determine rates, which is the TIER approach discussed above, is "unlikely to present the same potential risks to KIUC's customers as compared to those present for customers of for-profit."[157]

[153] Order No. 35411, at 53.

[154] Order No. 35411, at 55.

[155] Order No. 35411, at 55.

[156] *See Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5, § 3.

[157] Order No. 35411, at 9-10.

4 General assessment of the strengths and challenges of the current regulatory model in Hawaii

The assessment of the current regulatory model, including its strengths and weakness, is high level and qualitative. The Project Team evaluated the strengths and weaknesses based on the key characteristics of a good regulatory model and its performance relative to the policy goals for electricity sector espoused by the administration. As will be discussed below, the strengths of the current regulatory model include PUC's "independence", participatory regulatory process, rates are set to allow utilities a fair return, and policies are in place to achieve diversifying the state's energy portfolio. Areas for improvements include providing incentives in utilities' performance, providing certainty with regards to timeline on issuing regulatory decisions, and taking into account other elements that mitigate risks in the final design of the PBR.

4.1 Strengths of the current regulatory model

The current regulatory model has several strengths including the PUC's independence and innovativeness, a participatory regulatory process, a regulatory model that allows rates to be set to allow utilities a reasonable rate of return, and policies that are in place to achieve diversifying the state's energy portfolio. These are detailed further below:

- **PUC is independent and innovative**. The PUC is structured with fixed terms of Commissioners, once appointed and confirmed by the Senate, to be generally independent of political affairs and regulated public utilities. Independence is important so that the commission will be able to discharge its functions effectively and fairly. As mentioned earlier, Commissioners are appointed on staggered six-year terms that provide some shelter from short term sometimes shifting political winds. The PUC has shown innovativeness and openness to deviating from traditional ratemaking to institute various elements of PBR and various incentive mechanisms as discussed above.

- **PUC can adapt to the changes in the regulatory environment**. The PUC has shown that it is ready and able to adapt to changes when necessary.

- **PUC Commissioners and staff are deeply knowledgeable about the issues**. This enables the Commissioners to adapt to changes and policy directives.

- **Public participation in the regulatory process is encouraged**. Public participation raises the public's confidence in the Commission. It also ensures that the Commission considers the issues that are important to the stakeholders in its decisions. As mentioned earlier and as part of its mission, the PUC should "address the goals and future needs of the State in the most economically, operationally, and environmentally sound manner."[158] In PUC's review of dockets, stakeholders are encouraged to express their standpoints, which serves

[158] Hawaii PUC. *Goals and Objectives of the Commission*. Website. <http://puc.hawaii.gov/about/goals-objectives/>. Access Date: March 2, 2018.

as a foundation for the PUC to balance considerations from different perspectives. Therefore, the Project team sees this as a strength of the current regulatory model.

- **Utilities are performing as expected in terms of providing reliable service**. The PUC had acknowledged this in Order 35411 when it stated that "utilities under the COS have successfully provided reliable service while affording regulated utilities a reasonable opportunity to ensure their financial integrity."[159]

- **Rates are set to allow the utilities to earn a fair return**. The utilities currently earn fair and reasonable returns as mentioned in their financial report. Moreover, the return on equity ("ROEs") authorized by the PUC to the utilities have historically been slightly above industry average at the time established, more recent authorizations have been slightly below the industry average.[160] The industry average was 9.99% in 2013 and 10.14% in 2012, according to Edison Electric Institute. The PUC authorized MECO, HECO, and HELCO, an ROE of 9% (in 2013), 10% (in 2012) and 10% (in 2012) respectively,[161] all slightly below the industry average, as shown in Figure 9.[162] In the current pending rate cases, HECO Companies requested an ROE of 10.60%, which is higher than the industry average requested ROE in 2016 and 2017 (Figure 9).[163] But the PUC has not issued a decision and order on these rate cases yet.

Figure 9. Comparing ROEs of HECO Companies and Industry Average

	HECO	HELCO	MECO	Industry Average
2012 (approved)	10.00%	10.00%	N/A	10.15%
2013 (approved)	N/A	N/A	9.00%	9.99%
2016 (requested)	10.60%	10.60%	N/A	10.43%
2017 (requested)	N/A	N/A	10.60%	10.27%

Source: S&P Global. EEI Rate Case Summary. Q4 2017.

- **Policies are in place to help in diversifying the State's energy portfolio**. Hawaii regulators and legislators have issued several regulatory orders and laws regarding clean energy goals for Hawaii, including the ambitious RPS goals, which pushes the market to diversify the energy portfolio. In addition, the PUC has made major progress on several dockets and issued orders to help achieve a diversified energy portfolio in Hawaii. The

[159] Order No. 35411, at 11.

[160] S&P Global Market Intelligence. *Commissions: Hawaii PUC.* Website. <https://platform.mi.spglobal.com/web/client?auth=inherit#industry/commissiondetails?ID=4136041&Type=1&State=HI>. Access Date: March 2, 2018.

[161] Ibid.

[162] EEI. Edison Electric Institute's Rate Case Summary. 2012 and 2013.

[163] Edison Electric Institute. *Rate Case Summary*. Q4 2017 Financial Update. Page 4.

related dockets include but not limited to *HECO Companies' Power Supply Improvement Plans ("PSIPs") (Docket No. 2014-01893)*, *Distributed Energy Resource Policies Investigation (Docket No. 2014-0192)*, and *Community Based Renewable Energy Program (Docket No. 2015-0389)*, etc.[164] Moreover, the Hawaii PUC continues monitoring the implementation of the policies. Utilities are required to submit RPS reports to the PUC every year through 2021.[165] The PUC also approved a penalty of $20 for every MWh that an electric utility is deficient under Hawaii's RPS Law (HRS 269-91 to 269-95).[166]

Figure 10. Forecasted RPS and renewables (MW) by 2021

Island and County	Forecast RPS (%)	Forecasted Renewables (MW)
Molokai Island (Maui County)	142%	8.50
Hawaii Island (Hawaii County)	80%	235.30
Maui Island (Maui County)	63%	284.00
Lanai Island (Maui County)	59%	6.70
Oahu Island (Honolulu County)	45%	1,299.00

Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 1, pages 6-11 to 6-21.

Having achieved 23.2% of the RPS target by 2015, the HECO Companies surpassed the state's 2015 RPS target of 15%.[167] According to HECO's PSIP, they expect to achieve the future RPS targets ahead of schedule, anticipating reaching 48% renewable energy target by 2020, 18% more than mandated by the state's RPS rules.[168] By 2021, each island is forecast to meet more than 40% of the RPS target as shown in Figure 10. The Puna Geothermal Venture ("PGV"), a geothermal power plant on the Hawaii island, was shut down in May 2018 due to the volcanic eruption of Kilauea.[169] Mayor Harry Kim authorized a permit for PGV to clear lava for a road to its site in December 2018, and the operators have started restoring road access to the property.[170] Moreover, in early January 2019, HECO Companies submitted contracts for seven grid-scale, solar-plus-storage

[164] Hawaii PUC. *Annual Report for Fiscal Year 2017*. December 2017.

[165] Hawaii PUC. *Decision and Order No. 23912*. (Docket No. 2007-0008). Page 8.

[166] Hawaii PUC. Order Relating to RPS Penalties. (Docket No. 2007-0008). Page 1.

[167] Hawaiian Electric Company. "Record highs for renewable energy use in 2015." April 2016. <https://www.hawaiianelectric.com/Documents/my_account/customer_newsletter/hawaiian_electric/2016/hawaiian_electric_2016_04.pdf>

[168] HECO. *PSIP Update Report*. December 23, 2016. Book 1, page 41.

[169] HSEO. *Hawaii Energy Facts & Figures* (June 2018). Page 23.

[170] Associated Press. "Work begins to restore access to lava-locked Puna Geothermal." December 13, 2018.

projects on Oahu, Maui, and Hawaii Island to the PUC for review. The projects will add approximately 262 MW of solar energy with 1,048 MWh of storage.[171]

Likewise, KIUC has exceeded the 2016 RPS goal of 30% by having 41.66% of its net electricity sales from renewable energy resources.[172] The RPS level in 2016 has also surpassed the 30% by 2020 RPS goal by 11.66% and the 40% goal by 2030 RPS requirement by 1.66%. Moreover, KIUC expects to reach 50% renewable in 2018 – five years ahead of the initial goal in Strategic Plan 2008-2023.[173] According to KIUC's 2016 Annual RPS Status Report, it is on target to exceed the next RPS requirement of 70% by 2040.[174] As of 2017, more than 44% of KIUC's electricity came from renewable energy sources.[175]

Therefore, the current regulatory model makes it possible for the utilities to comply with the requirements set by the PUC and are ahead in meeting the clean energy target.

- **Platforms are provided to the utilities to be able to leverage the state's position as an innovation test bed.** One of the state goals is to make Hawaii an innovation test bed. Under the current regulatory model, the utilities were provided with the opportunity to implement several innovative programs that use new energy solutions. For instance, in its Decision and Order No. 34924, the PUC approved two innovative programs for HECO Companies on October 20, 2017. The Smart Export program and the Customer Grid-Supply Plus ("CGS +") will expand opportunities for customers to install rooftop solar and battery energy storage systems.[176]

- **If designed correctly, the proposed PBR will be able to help achieve the goals set by the PUC.** As discussed earlier, the PUC has introduced a proceeding to investigate the PBR**.** PBR offers many potential benefits to regulators, utilities, and customers. These benefits include superior performance incentives, improved rate predictability,[177] timely consumer benefits, lower administrative/regulatory costs, and greater compatibility with

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[171] HECO. "New solar-plus-storage projects set low-price benchmark for renewable energy in Hawaii." January 3, 2019.

[172] KIUC. "Docket No. 2007-008 - In the Matter of Public Utilities Commission Instituting a Proceeding to Examine Hawaii's Renewable Portfolio Standards Law, Hawaii Revised Statutes ("HRS") §§ 269-91 — 269-95, as Amended by Act 162, Session Laws of Hawaii 2006: Kauai Island Utility Cooperative's ("KIUC's") 2015 Annual Renewable Portfolio Standards ("RPS") Status Report." April 11, 2017.

[173] KIUC. *KIUC Board Sets Renewable Energy Goal of 70 percent by 2030*. February 1, 2017.

[174] KIUC. "Docket No. 2007-008 - In the Matter of Public Utilities Commission Instituting a Proceeding to Examine Hawaii's Renewable Portfolio Standards Law, Hawaii Revised Statutes ("HRS") §§ 269-91 — 269-95, as Amended by Act 162, Session Laws of Hawaii 2006: Kauai Island Utility Cooperative's ("KIUC's") 2015 Annual Renewable Portfolio Standards ("RPS") Status Report." April 11, 2017

[175] KIUC. *KIUC's 2017 Annual Renewable Portfolio Standards ("RPS") Status Report*. March 29, 2018.

[176] Hawaii PUC. *Annual Report for Fiscal Year 2017*. December 2017.

[177]Olson, Wayne and Caroline Richards. "It's All in the Incentives: Lessons Learned in Implementing Incentive Ratemaking." *The Electricity Journal*: 20-29.

a rapidly changing industry. PBR can also provide strong incentives to increase performance and improve productivity because it allows a utility to derive a significant financial benefit from doing so.[178] This benefit is precisely the incentive that motivates utilities in competitive markets to control costs and deliver exceptional service to their customers. Nevertheless, the devil is in the detail.

4.2 Areas of improvements in the current regulatory model

Under the current regulatory model, there are several potential improvements that can be made. These include providing incentives in utilities' performance, providing certainty with regards to timeline on issuing regulatory decisions, reducing complexity and cost of regulation and regulatory compliance and mitigate risks in the establishment of the final design of the Performance-Based Regulation ("PBR").

- **Most of the current performance metrics are for tracking only**. As mentioned earlier, only a few of the performance standards have any rewards or penalties set. With the implementation of the PBR, it is important to establish performance standards along with efficiency incentives to ensure that any cost reductions implemented by the utility will not cause a deterioration in service quality. When properly designed, performance standards should ideally meet a variety of different objectives such as aligning incentives by offering financial rewards for service level improvements, ensuring a high level of service and protect consumers from hidden costs increases and poor service quality, and allowing corrective measures, to name a few. Standards must be attainable, measurable, and verifiable, and must be consistent with customer needs or expectations and what customers are paying for. However, setting the criteria and financial incentives (or penalties) for performance requires additional administration and management.

- **Regulatory proceedings sometimes take longer than nine months.** Uncertainty over when the Commission issues its decision puts the utilities at a disadvantage when conducting business. Currently, as discussed above, in rate cases the law states that PUC has nine months from the time that the filing was made. However, for the past ten years, it has taken the PUC between 7 months and 31 months to decide on rate cases as shown in Figure 11.

- **Increasing complexity and cost of regulation and regulatory compliance**. The regulatory framework, which was already time-consuming and complex under traditional COS regulation, is further increasing in complexity with decoupling and various elements of PBR already having been established and implemented and will continue to increase in complexity as the Ratepayer Protection Act is implemented and the PBR Docket proceeding establishes additional PBR mechanisms. The complexity increases costs of the PUC and the Consumer Advocate, and increases costs for electric utilities, which passes on such costs to its ratepayers. Minimizing complexity may seem

[178] Sappington, David, Johannes Pfeifenberger, Philip Hanser, and Gregory Basheda. "The State of Performance-Based Regulation in the US Electric Utility Industry." *The Electricity Journal*. October 2001.

at odds with other initiatives, but consideration should be given to reducing or at least minimizing the increase in complexity of regulation and regulatory compliance.

Figure 11. Number of months to decide a rate case (2009-2017)

Utility	*Docket*	*Date filed*	*Date decision was filed*	*Decision Type*	*Rate Case Duration (months)*
Hawaii Electric Light Co	D-2012-0099	8/16/2012	3/19/2013	Settled	7
Hawaii Electric Light Co	D-2009-0164	12/9/2009	4/4/2012	Settled	28
Hawaiian Electric Co.	D-2013-0373	6/27/2014	12/23/2016	Fully Litigated	30
Hawaiian Electric Co.	D-2010-0080	7/30/2010	6/29/2012	Settled	23
Maui Electric Company Ltd	D-2014-0318	12/30/2014	8/4/2017	Fully Litigated	31
Maui Electric Company Ltd	D-2011-0092	7/22/2011	5/31/2013	Settled	22
Maui Electric Company Ltd	D-2009-0163	9/30/2009	5/2/2012	Settled	31

- **Other elements in the PBR should be considered in the final design.** Order No. 35411 discusses the PBR mechanisms that the PUC hopes to achieve which included greater cost control and reduced rate volatility, efficient investment and allocation of resources, fair distribution of risks between utilities and customers and fulfillment of state policy goals, as mentioned in Section 3.5. The discussion was focused heavily on revenue adjustment mechanisms and performance incentive mechanisms. The preparation of PBR filings requires the ability to forecast additional elements that may have been less critical under a COS regime.[179] Forecasting plays a central role in the building blocks approach-based PBR. Poor forecasting on the side of the utilities can also lead to potential additional costs and/or penalties affecting their bottom line. Realistically speaking, forecasts can significantly deviate from actual figures so the PBR design must include mechanisms that will provide a degree of protection to both the shareholders and ratepayers.

  These mechanisms may include re-openers/offramps, true-ups, and exogeneous factors ("Z-factors"). [180] Re-openers provide a degree of protection to both the shareholders and ratepayers. They provide utilities a way to modify the ratemaking mechanism before the end of the regulatory term or exit out of the regulatory regime if certain exceptional

[179] Items to forecasts include load growth, energy growth, depreciation, number of customers, cost of capital, operating expenditure, capital expenditure, and tax expenditure, to name a few.

[180] In UK, Ofgem developed an innovative mechanism called the menu approach or the information quality incentive ("IQI") to address forecasting challenges in capex and opex. This mechanism provides an incentive to utilities to present reasonable estimates of their true investment needs and penalize them if the information is misleading. It allows utilities to choose an implicit "regulatory contract" that provides the best incentive to declare the most accurate investment plans. In addition, it rewards utilities with lower expenditure forecasts and provides for utilities with higher expenditure forecasts to beat the targets by spending less.

circumstances materialize. During the review period of the PBR proposal, events or criteria are defined that will trigger an off-ramp event.

True-ups adjust rates between rate cases based upon the over or under-recovery of target revenues. True-ups arise due to three potential reasons: (i) operating costs differed from the forecast, volumes/customers differed from forecasts, or (iii) collection and bad debt expense rose. Timing of true-up is important; the less frequently it occurs, the more important it is to factor in the cost of capital, whether payments are to utility from customers or vice versa.

Z-factor is a mechanism to recoup extraordinary costs that are outside the utility's ability to control and is not included in the current escalation formula. It can either be defined by specific events or can be broader and include events which meet pre-established criteria.

5 Appendix A: Scope of work to which this deliverable responds

Task 2.1.2 General assessment of the existing regulatory model in place in Hawaii, including strengths and weaknesses.

CONTRACTOR shall provide a general assessment of the existing regulatory model in place in Hawaii.

DELIVERABLE FOR TASK 2.1.2. CONTRACTOR shall provide its conclusions and all work related to an assessment of the existing regulatory model in Hawaii. CONTRACTOR shall provide an MS Word document describing strengths and weaknesses of the current model, with an emphasis on how the current model performs related to policy goals for the electricity sector espoused by the administration. CONTRACTOR shall submit deliverable for TASK 2.1.2 to the STATE for approval.

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Preliminary and high-level evaluation of the regulatory models relative to Hawaii State's goals

A working paper prepared by London Economics International LLC with support from Meister Consultants Group for the State of Hawaii

August 16, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This document is one of several working papers associated with that engagement. Five utility regulatory structures were reviewed in more detail based on the team's preliminary evaluation of various potential regulatory arrangements: (i) status quo, (ii) status quo with increased oversight, (iii) independent system operator, (iv) distribution-focused regulatory model, and (v) performance-based regulation ("PBR") model. Key differences among these models include varying regulatory oversight over different sectors of the electricity value chain and the role of utilities in owning and operating the assets. Our preliminary evaluation of these regulatory models shows that the PBR model scores highest while the status quo performs the least favorably across the six criteria (including the five listed in the State legislation directing this research) considered: (i) the ability to facilitate the achievement of state energy goals; (ii) adequacy of mechanisms that can maximize consumer cost savings; (iii) relevance of arrangements towards a competitive distribution system; (iv) availability of features that minimizes or addresses conflicts of interest; (v) availability of innovative approaches that align stakeholder interests; and (vi) inherent process that help reduce transition costs.

The Project Team also notes that:

- ***a hybrid model with a combination of some of these models could be more effective in achieving all the State's goals than any single regulatory model on its own;***
- ***a reduced Public Utilities Commission ("PUC") oversight model is worthy of consideration for Kauai County.***

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List of acronyms

AMI	Advanced Metering Infrastructure
CAPM	Capital Asset Pricing Model
CGS +	Customer Grid-Supply Plus
COS	Cost of Service
DBEDT	Hawaii Department of Business Economic Development and Tourism
DCA	Hawaii Division of Consumer Advocacy
DCF	Discounted Cash Flow
DG	Distributed Generation
DER	Distributed Energy Resource
DSO	Distributed System Operator
DSPP	Distributed System Platform Provider
DUOS	Distribution use of the system
EAM	Earning Adjustment Mechanism
ECAC	Energy Cost Adjustment Clause
EIA	US Energy Information Administration
EMA	Electricity Market Authority
ERC	Energy Resources Coordinator
ERCOT	Electric Reliability Council of Texas
ESM	Earnings Sharing Mechanism
FERC	Federal Energy Regulatory Commission
HCEI	Hawaii Clean Energy Initiative
HECO	Hawaiian Electric Company, Inc.
HEI	Hawaiian Electric Industries
HELCO	Hawaii Electric Light Company, Inc.
HERA	Hawaii Electricity Reliability Administrator
HRS	Hawaii Revised Statutes
HSEO	Hawaii State Energy Office
IDSO	Independent Distribution System Operator
IOU	Investor-Owned Utility

IPP	Independent Power Producers
IRP	Integrated Resource Plan
ISO	Independent System Operator
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company, Ltd.
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NTA	Non-Transmission Alternative
NWA	Non-Wires Alternative
PBR	Performance-based Regulation
PIMs	Performance Incentive Mechanisms
PPAC	Purchased Power Adjustment Clause
PSIPs	Power Supply Improvement Plans
PUC	Hawaii Public Utilities Commission
RAM	Revenue Adjustment Mechanism
RBA	Revenue Balancing Account
REV	Reforming the Energy Vision
ROE	Return on Equity
RPS	Renewable portfolio standards
RTO	Regional transmission organization
RUS	Rural Utilities Service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TIER	Times Interest Earned Ratio
TIS	Texas Interconnected System
TOU	Time of Use
TTC	Total transmission capacity
UK	United Kingdom
USDA	United States Department of Agriculture
WACC	Weighted Average Cost of Capital

1 Executive summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which responds to Task 2.2.1 in the project scope of work, provides a high-level evaluation of the selected regulatory models relative to the State's goals. Those goals, enshrined in the legislation authorizing this research, are shown in the textbox below.[1] The Project Team also evaluated the strengths and weaknesses of the existing regulatory model in Hawaii to contextualize the discussion of whether other regulatory models address improvements needed (if any) in the current model.

Five utility regulatory structures were selected following the Project Team's evaluation of various additional potential regulatory arrangements, with a specific focus on relevance to the needs of Hawaii. These include:

- status quo;
- status quo with increased oversight;
- independent system operator ("ISO");
- distribution-focused regulatory model; and
- performance-based regulatory ("PBR") model.[2]

These models differ in terms of regulatory oversight over different segments of the electricity value chain in each model, the role of utilities in planning functions and at the distribution level, and the relative importance of varying revenue generation streams for the utilities. The PBR model introduces additional incentives and penalties on top of existing revenue streams. A distribution-focused model could create other earning opportunities for the utilities. However, the ownership and fundamental business model of the utilities is assumed to remain the same under all regulatory models.

State's key criteria in evaluating models based on the legislation

- Achieve State energy goals
- Maximize consumer cost savings
- Enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs
- Eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation

Source: House Bill No. 1700 Relating to the State Budget

Except for the status quo, each of the other regulatory models would require a series of actions to implement. Some of these models would need the issuance of rules or Orders by the PUC to initiate the establishment of a new entity or define a new structure. Subsequent steps common to several of the potential regulatory forms include the development of a surcharge to support the

[1] Hawaii State Legislature. *House Bill No. 1700 Relating to the State Budget.* June 24, 2016.

[2] As discussed in Task 2.1.1., we have three variants of PBR for Hawaii, namely (i) Light PBR, (ii) Conventional PBR, and Outcomes-based PBR.

operation of the new entity, hiring of new staff and experts for the new entity, and assumption of new roles, to name a few.

Based on our high-level qualitative and preliminary evaluation of the regulatory models relative to the State's goals, we find that the PBR model is best positioned to address the State's priorities. It received the highest rating in three of six criteria and second highest rating in another criterion. The expected performance of other models varied substantially; the status quo regulatory model received the lowest assessment overall.

It should be noted that these models are not mutually exclusive and may be combined. The Project Team also evaluated potential hybrid models--(i) combining a variant of PBR with a HERA entity with modified functions; and (ii) combining PBR with the distribution-focused regulatory model. Based on our analysis, we found these two models to be potentially more effective in meeting the State's criteria than some of the stand-alone regulatory models. The Project Team also considered a reduced oversight model for Kauai County because it has a different utility ownership structure than the other counties. Preliminary analyses indicated both the advantages and disadvantages of this regulatory model, making it worthy of more in-depth analysis in future deliverables.

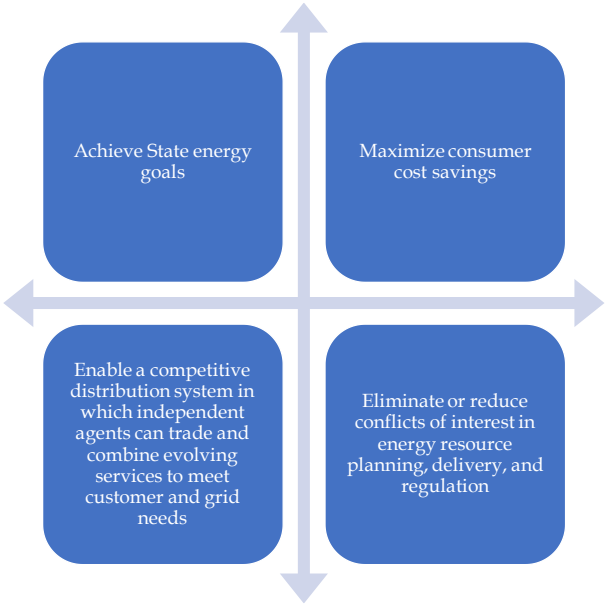
2 Introduction and scope

2.1 Project description

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the State legislature to commission a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[3] was contracted to perform this study.[4]

The project aims to evaluate the ability of each model to achieve the State's key criteria[5] (Figure 1).

Figure 1. State's key criteria in evaluating the models



Source: Scope of Services under Contract No. 65595

The study will help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the State. Moreover, it will also aid in identifying the process required in forming such ownership and regulatory models as well as in determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy

[3] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[4] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[5] House Bill No. 1700 Relating to the State Budget.

resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[6]

2.2 Relevance of this deliverable relative to others in the project

This deliverable is responsive to Task 2.2.1 in the project scope of work. It introduces the various types of regulatory models and evaluates their characteristics. It also summarizes a comparison of the regulatory models from Hawaii's perspective, assesses the existing regulatory model in place in Hawaii, and provides a high-level process assessment.

Moreover, various aspects of the regulatory models will be further explored in subsequent deliverables. This includes:

- assessment of current markets under each regulatory model, including a case study, analysis, and conclusions (Task 2.2.2);
- high-level assessment of the technical, financial, and legal feasibility of each regulatory model (Task 2.2.3);
- summary analysis and conclusions related to estimating stranded costs for each regulatory model (Task 2.2.4);
- soliciting public input from each island currently served by an electric utility on the results of Task 2.1.1 through 2.2.4 (Task 2.2.5);
- identification of and recommendations for the three most beneficial regulatory models for further consideration (Task 2.2.6);
- identification of steps, costs, and projected timelines, if there would be a change from the current regulatory model to the recommended regulatory models (Task 2.3.1);
- analysis of Hawaii law and history to determine the regulatory and legislative changes needed to implement the recommended regulatory models (Task 2.3.2);
- identification and assessment of the impact of financial and operational risks for different stakeholders under each regulatory model (Task 2.3.3);
- evaluation of how each recommended model impacts State agencies staffing and stakeholders (Task 2.3.4);
- estimation of potential of each model in increasing distributed energy resources (Task 2.4.1); and
- evaluation of revenue requirements, system average retail rates, risks to utility valuations, and funding mechanisms for each regulatory model (Task 2.5).

[6] Hawaii Contract No. 65595. Scope of Services.

2.3 Future refinements

As noted earlier, this deliverable is intended to serve as an introduction to the different regulatory models and, as such, the results of our analysis are subject to further refinement and changes as the project moves forward and inputs from stakeholder groups and results of quantitative analysis and case studies become available. LEI will provide case studies in some of the deliverables (if applicable) to highlight the essential features of the different regulatory models and key issues and lessons from other jurisdictions or utilities. Furthermore, the project will provide various opportunities for stakeholder inputs and participation. LEI will engage a wide range of stakeholders and perspectives across all islands through a series of facilitated dialogues, one-on-one meetings, and workshops.[7]

[7] A series of community meetings across the State were held in June 2018 in Hawaii. The workshops provided opportunities for the attendees, as well as online participants, to hear from key stakeholders in the energy policy discussion and provide inputs to the study through small group discussions.

3 Similarities and differences of the regulatory models

As introduced in Task 2.1.1, five regulatory models are being considered in this evaluation. These models are not mutually exclusive, and some of these models and/or their features could co-exist. These regulatory structures were determined based on legislative mandates (such as the Hawaii Electricity Reliability Administrator ("HERA") and the ongoing PBR proceeding), the emerging market trends in high renewables penetration jurisdiction, current state goals, and our high-level evaluation of various additional potential regulatory arrangements. The six selected regulatory models[8] are listed below:

1. status quo;
2. status quo with increased oversight ("the HERA model");
3. independent system operator ("ISO");
4. distribution-focused regulatory model; and
5. performance-based regulation ("PBR") model.

Furthermore, the Project Team determined three potential PBR models suitable to Hawaii. As discussed in Task 2.1.1, PBR is not a single type of regulatory regime but comprises various mechanisms and combinations. The three PBR variants are:

1. Light PBR;
2. Conventional PBR; and
3. Outcome-based PBR.

Each of these models entails a different approach to regulating entities in the Hawaii power sector. Some of these regulatory models (such as the HERA model, ISO, and distribution-focused regulatory model) require delegating some of the responsibilities of the Public Utilities Commission ("PUC") to an independent entity, while others such as the PBR would require modified oversight from the PUC. This section describes the regulatory models, focusing on their similarities and differences. The Project Team reviewed the regulatory models across three (3) key parameters to ensure coherence and consistency:

- ***utility's role across the value chain***: the role of the utilities in the regulatory model in each step of the value chain—including generation, system operator, transmission, and distribution. More specifically, we will consider whether the utilities will own and operate the assets and perform the planning or will there be an independent entity that will take over some of the responsibilities of the utilities.

[8] A lighter regulation for KIUC was also assessed in Section 7.

- ***utility's motivation:*** we will determine what incentives or disincentives will each regulatory model provide a utility, particularly, vis-à-vis its decision-making in investments in capital expenditure vs. operations and maintenance ("O&M") or in aligning its goals with the State's goals;

- ***oversight and monitoring:*** we will evaluate how will the oversight responsibilities of the Commission change across the energy value chain and if some of the current duties of the PUC will be passed on to another entity and if so, how will changes ensure effective monitoring.

Figure 2 shows a summary of the similarities and differences of the models (based on the recommended parameters), with relevant components described in greater detail below.

Figure 2. Similarities and differences of the regulatory models

	Status Quo	Status quo with increased oversight	ISO	Distribution-focused regulation	PBR
Utility role across value chain					
Asset ownership	X	X	X	X	X
Asset operation	X	X	X	X	X
Investment planning and execution	X				
Utility motivation					
Incentive to increase/decrease spending	X				
Incentive to increase/decrease investment	X				
Maintain operational control	X	X			X
Regulated revenues in ratebase	X	X	X	X	X
Market-based revenues			X	X	
Oversight and monitoring					
PUC	X	X	X	X	X
Independent monitor		X	X	X	

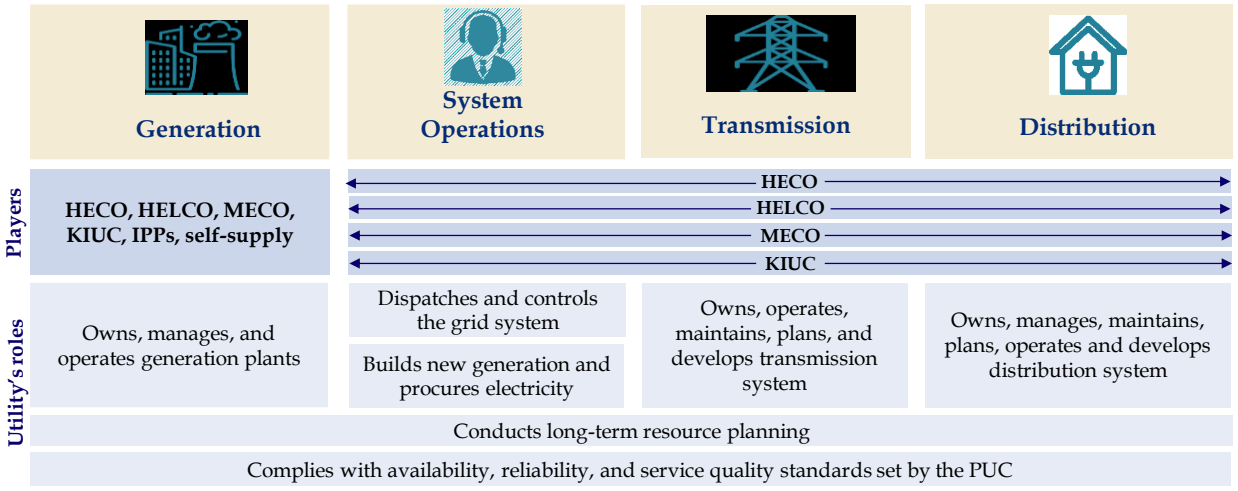
Note: "X" indicates that the feature is present in the model. PBR captures all three variants described in Task 2.1.1 – their similarities and differences in terms of the categories in the table above are identical.

3.1 Utility's role across the value chain

The utility's role across the value chain differs slightly in each of the regulatory models depending on the structure of the energy sector, but in no case does the utility disappear. As discussed in Task 2.1.2, some of the key roles of the utilities in Hawaii are shown in Figure 3.

Both the status quo and PBR regulatory models maintain the existing structure, where the HECO Companies and KIUC are vertically integrated and regulated by the Commission.[9] Under these models, the utilities are the major generators as well as owners and operators of transmission and distribution assets in their respective service areas. Investment planning and plan execution are performed by the utilities themselves, with approval from the Commission. The significant difference lies in the approach to the setting of utility rates and returns by the Commission. The utilities will continue to be under a cost-of-service ("COS") approach under the status quo while the Commission will apply a Hawaii-specific PBR mechanism under the PBR model.

Figure 3. Current key roles of the utilities across the value chain



Under the HERA model, the existing regulatory model is augmented with the creation of HERA. The utilities will maintain their current roles (i.e., generation, transmission, and distribution) across the electricity supply value chain. However, the utilities will be required to meet increased reliability and open access requirements, under the oversight of HERA. Investment planning and execution may also be subject to increased scrutiny from HERA. As discussed in Task 2.1.1, a Light HERA model requires the creation of an administrative body, which functions as an ombudsman and appeals body. Figure 4 shows the additional task of the utility under this model.

Meanwhile, under the ISO regulatory model, the newly-formed ISO either acquires or leases the transmission control and monitoring assets of the utilities. The utilities retain ownership over the transmission assets and control and ownership of the distribution system. In this model, the ISO conducts transmission planning studies along with the utilities. Upon approval of the PUC, the utilities will implement the plan and invest in and maintain the transmission facilities. The incumbent utilities' generation business may be retained or spun off into a subsidiary whose focus is on participating in the wholesale market. Figure 5 illustrates the roles of the ISO and utilities under an ISO model.

[9] The existing regulatory model in Hawaii is evaluated in detail in Task 2.1.2, where the team provides an overview and general assessment of the existing regulatory model.

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Figure 4. Key roles of the utilities across the value chain under a Hawaii HERA model

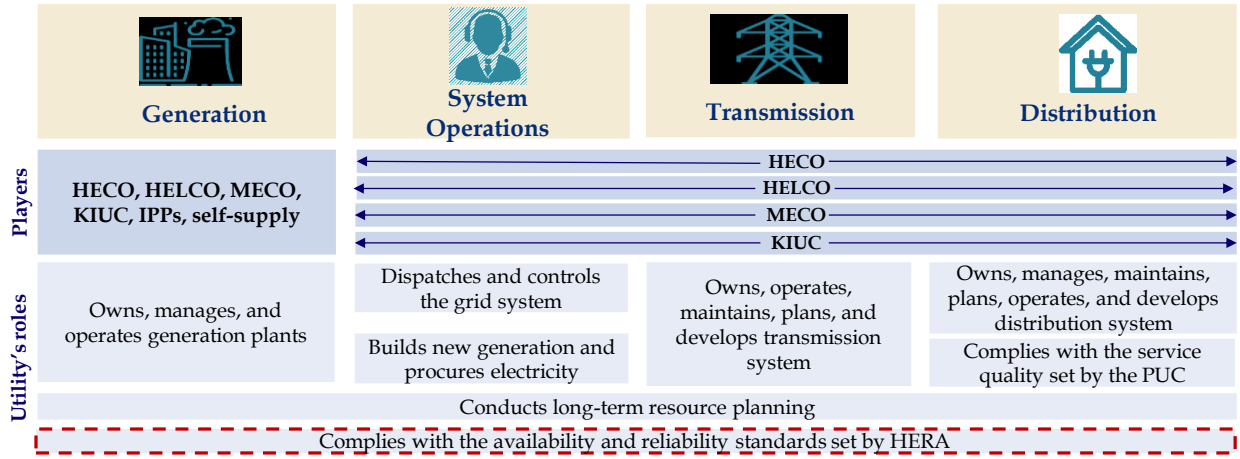
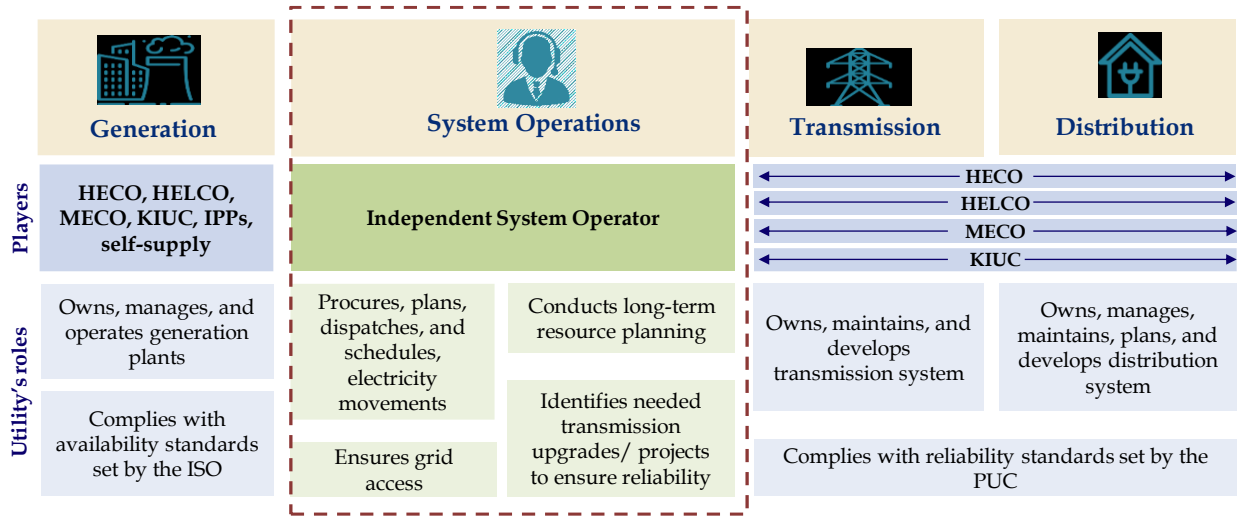


Figure 5. Key roles of the utilities across the value chain under ISO model

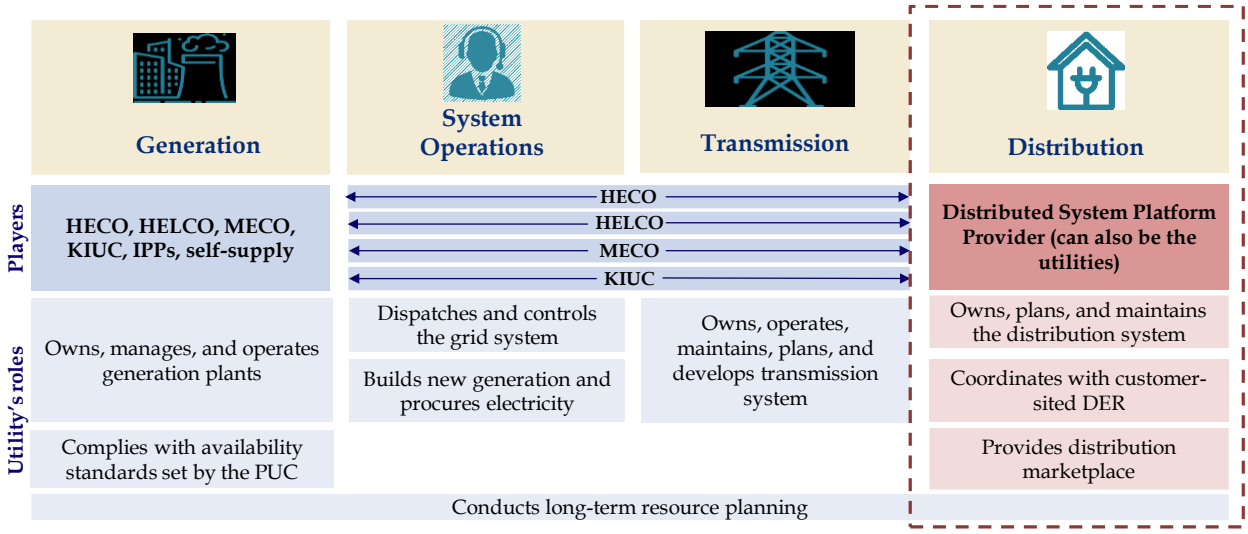


Under the distribution-focused regulatory model, the utilities facilitate the integration of distributed energy resources ("DER") into the grid. Ownership and control of utility-scale generation and transmission assets remain with the utilities in this model. The primary difference of this model relative to the first two described above is in the low-voltage distribution grid, where the utility is encouraged to provide distributed system platform services to enable third-party DER providers to create value for both customers and the system itself.[10] In this regulatory model (where investment planning and execution are carried out by the utilities), the Commission may also mandate the creation of a Distribution System Operator ("DSO"), which would perform the same duties as an ISO essentially but focused on the distribution-level

[10] DeMartini & Kristov. *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation & Oversight.* Lawrence Berkeley National Lab. October 2015.

system.[11] The utilities still own the distribution assets, but the operations of the distribution grid will be handled by the DSO in this regulatory model. Figure 6 depicts the roles of the utilities under the distributed-focused regulatory model.

Figure 6. Key roles of the utilities across the value chain under the distributed-focused regulatory model (DSSP)



3.2 Utility's motivation

The **motivation of the utility** can be derived by analyzing the incentives or disincentives created by the model, particularly utilities' investment decisions and the alignment of their goals to the achievement of the State's goals.

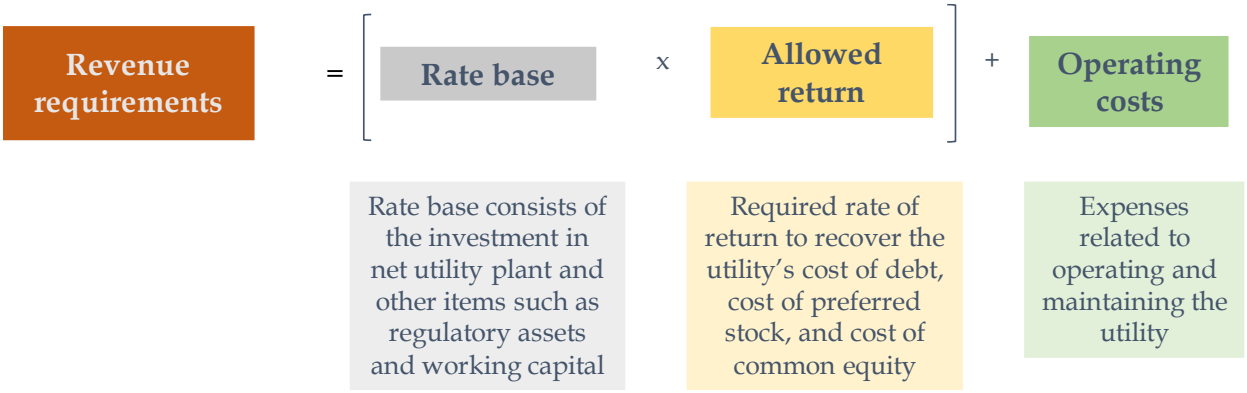
Under all the selected regulatory models (except for PBR), most or all of the sectors of the value chain will still be under the rate base or COS approach. Therefore, there is an inherent bias in spending more on capital infrastructure instead of operations and maintenance. This is because of the revenue requirement formula where the rate base—which includes capital investment—is multiplied by the rate of return whereas operating costs are not multiplied by the allowed return. Therefore, this formula provides a strong incentive for the utility to prioritize capital projects (Figure 7).

The proposed PBR regime in Hawaii aims to have no distinction between capital and operating expenditure in their revenue requirements. In the PUC order opening the PBR proceeding in Hawaii, it indicated that the proposed PBR regulatory model should encourage exemplary utility performance, saying that "*…PBR frameworks should result in an incentive structure that encourages exemplary utility performance irrespective of the nature of its investments (e.g., investment in capital*

[11] Ibid.

expenditures versus investment in efficiency measures)."[12] Therefore, under the proposed PBR, the utilities will not be biased toward capital expenditure. However, the PBR model can be implemented in conjunction with other proposed regulatory models and does not need to be a stand-alone option.

Figure 7. Revenue requirements formula



Under the ISO and independent DSO models, the utilities would still own and rate base their transmission and distribution assets and pass the transmission planning and dispatch to the ISO or the distribution planning to the DSO. Since independent entities (e.g., ISO and DSO) conduct the system planning through a stakeholder process (that involves utilities) and recommend the selected investments to the PUC, conflict of interest over investment decisions is reduced. Therefore, utilities have less influence on whether an investment is made—guarding against their incentives to over-capitalize the system, in the process.

3.3 Oversight and monitoring

As discussed in Task 2.1.2, the PUC's key responsibilities include approval of rates, fuel supply contracts, power purchase agreements, new generation builds, and resource planning as well as monitoring performance standards, reliability, and grid access, to name a few (Figure 8).

The role of the PUC changes slightly under HERA model. More specifically, the HERA entity, which will be responsible to the PUC, will oversee the reliability and grid access functions. The PUC will maintain its other responsibilities such as the approval of rates and large capital expenditure (Figure 9).

[12] Hawaii Public Utilities Commission. *Order No. 35411: Instituting a Proceeding to Investigate Performance-Based Regulation.* Docket No. 2018-0088. April 18, 2018.

Figure 8. Current key oversight responsibilities of the PUC

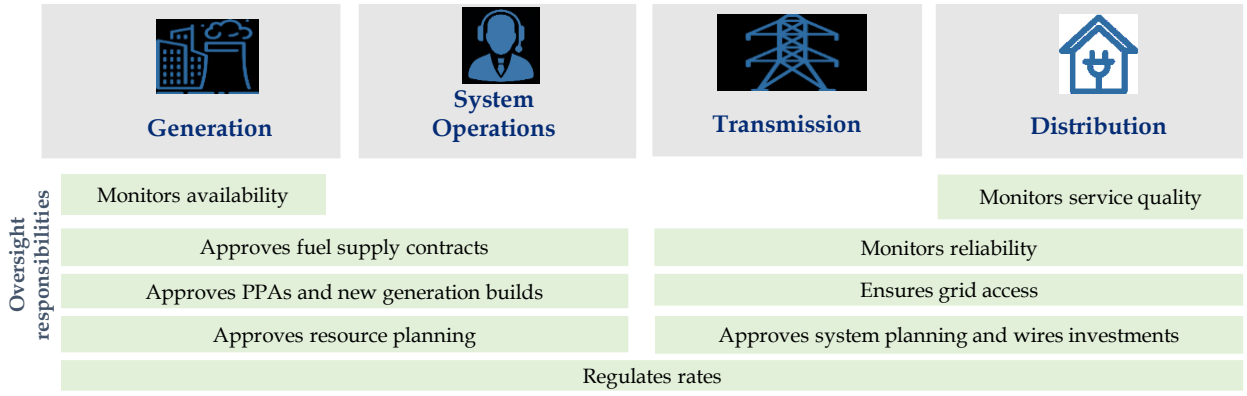
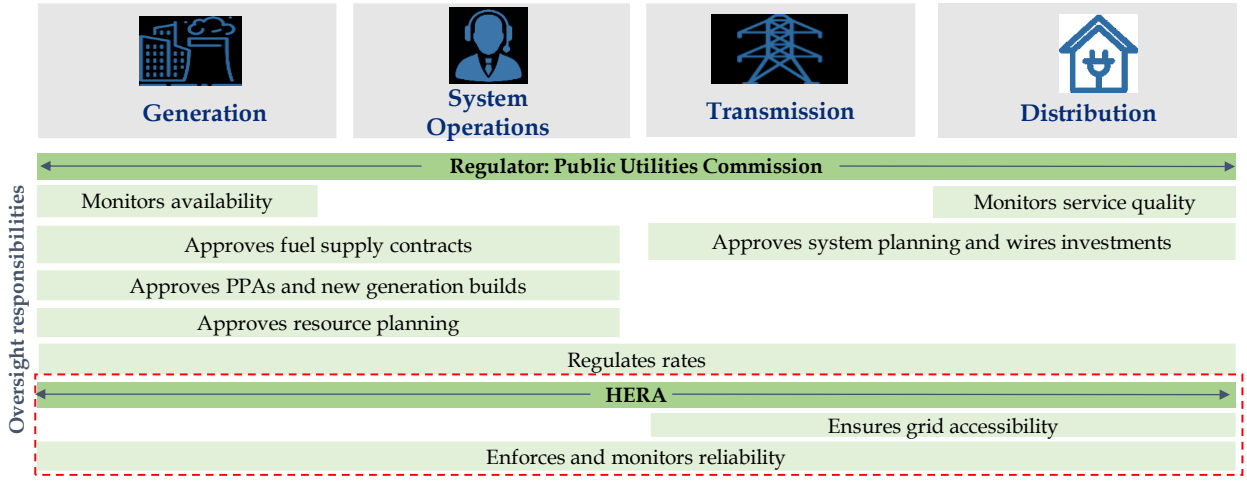


Figure 9. Key oversight responsibilities of the PUC under the HERA model



In the ISO and distribution-focused model, monitoring and oversight occur across multiple entities, with the Commission delegating market monitoring and competition assessment to the newly created entities. With the ISO model, the Commission's role in system planning and coordination is taken up by the new entity, with the ISO further responsible for short-term reliability and system operation. In the case of the distribution-focused model in Hawaii, the distribution-level planning, coordination, and oversight are also combined with the bulk power system. The smaller size of Hawaii's electric grid (especially in terms of transmission infrastructure) compared to mainland interconnections, makes it possible for the DSO to oversee both the transmission and distribution operations. In other words, the roles of the ISO and DSO can be performed by one independent entity. The regulator's role may be limited to the approval of capital expenditure, resource plans, and contracts, and management and resolution of disputes.

Finally, PBR requires the PUC—in addition to its current responsibilities—to develop new PBR mechanism and determine targets and metrics in assessing utilities' performance (under the new framework) and from there, come up with a system of rewards and penalties. This leads to the

additional role of the PUC under a PBR regime: monitoring the performance of utilities vis-à-vis the set targets and outcomes.

4 Advantages and disadvantages of each regulatory model

This section provides a high-level overview of the potential benefits and drawbacks of each regulatory model. The analysis considers these advantages and drawbacks from the perspective of the utility, the Commission, and ratepayers. A summary of the advantages and disadvantages of each regulatory model is illustrated in Figure 10 and are discussed in more detail in the following subsections.

Figure 10. Summary of advantages and disadvantages of each regulatory model

Regulatory Model	Advantages	Disadvantages
Status quo	Innovative and openness of PUC Participatory regulatory process raising public confidence in Commission and its decisions Existing framework allows utilities to earn a reasonable return	Limited incentives for utility performance Uncertainty with regards to timing of regulatory decisions Complexity and cost of regulatory compliance
Status quo with increased oversight (HERA)	Enforcement of open access and reliability standards Long-term view of reliability needs Recommend specific reliability standards relevant to Hawaii context Can develop into a center of excellence, expertise and best practices	Risk of ambiguity of roles between Commission and new entity Increased cost of HERA to fall on ratepayers
Independent System Operator ("ISO")	Efficiency gains of competition in the power supply market can lower costs to consumers and eliminate subsidies Additional benefits, such as improved reliability, better coordination, and reduced transaction costs	Technically complicated and requires highly-specialized staff High level of stakeholder engagement required to initiate Careful market design needed to mitigate implementation risk
Distribution-focused regulatory model	Potential for lowering costs to consumers as they shift consumption during peak hours via DERs Market efficiencies from increased competition of DER solutions Optimizing of environmental benefits of DERs in the system Potential to reduce grid costs through non-wire alternatives	Stranded cost risk exists which would be borne by consumers Technical complexity presents risk of high cost of implementation Extensive levels of consumer education required to optimize market participation Few best practices to learn from
Performance-based regulation ("PBR")	Drives innovation and better investment decisions Efficiency gains from PBR mechanisms can be shared with customers Incentive for utilities to operate more efficiently	Significant regulatory work may be required Requires lengthy stakeholdering efforts

4.1 Status Quo

The status quo represents the existing regulatory model in Hawaii.[13] The State government (Legislature and Governor) establishes energy policies through legislative enactments and resolutions that are further developed, implemented, and enforced by the PUC. The Hawaii State Energy Office ("HSEO") within the Department of Business Economic Development & Tourism ("DBEDT") assists in developing and implementing energy policy as may be provided by the State.

As mentioned earlier, electricity rates for the HECO Companies are generally determined through a COS approach (sometimes referred to as "rate return regulation") with some components associated with performance-based regulation such as the earning sharing mechanisms, penalties for non-achievement of specific performance standards (mostly in reliability), and a multi-year rate plan. Task 2.1.2 discusses the current regulatory model in Hawaii in detail.

4.1.1 Advantages

As discussed in Task 2.1.2, the current regulatory model has several strengths including the PUC's ***independence and innovativeness,*** as reflected in its openness to deviation from traditional ratemaking by instituting various elements of PBR and incentive mechanisms; a ***participatory regulatory process*** that raises the public's confidence in the Commission; a model that allows rates to be set, allowing utilities a ***reasonable rate of return***; and presence and implementation of policies that support the diversification in the State's energy portfolio.

4.1.2 Drawbacks

However, there are a number of potential improvements that can be made in the current regulatory model. These include the need to provide incentives that will encourage superior utility performance on specific metrics, provide certainty with regards to timeline on issuing regulatory decisions, and reduce complexity and cost of regulation and regulatory compliance.

4.2 Status Quo with increased oversight – the HERA model

As discussed earlier, the HERA is assumed to be implemented under the status quo with increased oversight model ("HERA model"). The HERA as an entity was established by the Hawaii State legislation (Act 166) in 2012 although there is currently no HERA entity in place as of this writing.

The increased oversight from HERA would not change the current structure of the electricity value chain. Utilities would continue to operate the transmission and distribution network under this regulatory model. Nevertheless, the PUC's role in ensuring grid access and reliability would

[13] A comprehensive assessment of the existing regulatory model in Hawaii is detailed in Task 2.1.2, where the Project Team reviews the energy industry, the rulemaking process, the ratemaking process and undertakes a general assessment of the strengths and weaknesses of the existing regulatory model.

be transferred to HERA in this regulatory model. As mentioned earlier, the Project Team is also analyzing a Light HERA option.

4.2.1 Advantages

Having a separate entity—that performs oversight and monitoring of interconnection and reliability standards—from the Commission allows ***more stringent enforcement*** of technical and reliability standards as well as a ***streamlined, transparent, and standardized interconnection process***. An independent entity that reports to the Commission on reliability standards is likely to take a ***long-term view*** on reliability needs for each county and recommend ***specific technical and reliability standards*** as counties seek to meet the renewable portfolio standards ("RPS") targets for the State.

Moreover, a HERA would ensure a fair and transparent interconnection process. HERA is expected to safeguard system reliability, resiliency, and accountability. It will also recommend specific reliability standards relevant to Hawaii context, given the unique features of the State.

Moreover, the HERA—as a separate entity dedicated to reliability standards monitoring and enforcement—can develop into a ***center of excellence, expertise, and best practices*** with regards to distributed energy resources integration. This is provided by the legislation, which allows the Commission discretion as to the specific roles that HERA can play. With such a purpose, HERA should provide training and technical assistance to counties and utilities seeking to comply with the State's RPS goals and reliability targets.

Finally, a study—commissioned by the Mayor's Office of Economic Development of Maui County (August 2017)—assessed the initial structure for HERA.[14] The study found that an independent organization such as HERA could be beneficial to the State particularly when it comes to overseeing planning, reliability standards, and interconnection processes.

A variant of this model, a Light HERA, could be designed to improve DER interconnection process as well as ***provide an independent assessment of the impact of DERs on local reliability***. Its narrow scope would allow the entity to develop stronger expertise on DER interconnection and hosting capacity analysis than a body like the PUC, which has more wide-ranging responsibilities. Moreover, the expertise would add more weight to its decisions as an ombudsman in dispute resolution. Having a separate entity that oversees these functions would accelerate DER interconnections as well as the resolution of disputes that usually take months under current PUC regulatory proceedings. Furthermore, a streamlined body has lower overhead costs and is less likely to create overlapping layers of jurisdiction and bureaucracy.

4.2.2 Drawbacks

However, a HERA model faces the ***risk of overlap*** of roles between the Commission and the new entity. Currently, the Commission is responsible for enforcement of reliability standards across

[14] Mayor's Office of Economic Development, Energy Commissioner, DKK, and SES. *Comparing the Structure and Function of a HERA to an ISO: Report and Task Analysis for use by the County of Maui.* August 25, 2017.

the State. The establishment of HERA would require the Commission to define the mandate of the new entity and potentially transfer this role to HERA, with the new entity reporting back to the Commission on its activities for the preceding year on an annual basis.[15]

Another potential challenge in the establishment of a HERA entity is the required ***funding***—which would ultimately fall on ratepayers.[16] The surcharge implemented to fund the HERA entity would be recoverable from ratepayers and, by definition, increases rates (with all other costs staying the same). In the Maui County Study, the authors concluded that it is difficult to demonstrate that the costs for the establishment of a separate entity would be covered by savings from changes to interconnection or reliability.[17]

In 2016, NERC indicated that its proposed total United States net funding requirement for the Electric Reliability Organization ("ERO") is equivalent to $0.0000389 per kWh, based on the aggregate net energy for load of the United States in 2015.[18] Therefore, using the total energy production in Hawaii for 2015, we can derive an annual budgetary requirement of $393,649.[19] Assuming an inflation rate of 2% per year and assuming the load forecast for 2018 from the Power Supply Improvement Plans ("PSIP") filings, an estimate of the 2018 budgetary requirement is $482,566. Start-up costs for the entity can be estimated based on historical start-up costs for reliability organizations, using data gathered by FERC on estimates of start-up costs for RTOs. Data on start-up costs for ERCOT indicates that it required ~$4.5 million to set up operations of its Reliability Entity.[20] A review of the investment costs for PJM Interconnection, Midwest Independent Transmission System Operator, and Southwest Power Pool revealed a range of $1.5 million to $10 million as the minimum necessary startup costs required for the functions of a

[15] Under the HRS 269-149, the Commission requires that the HERA entity, "*report to the commission each year on the date of agreement under section 269-147 following the original contracting between the Hawaii electricity reliability administrator and the commission on the status of its operations, financial position, and a projected operational budget for the fiscal year following the date of the report.*" (Source: Hawaii Revised Statutes, *HI Rev Stat § 269-149 (2017*), 2017).

[16] Under the HRS 269-146, the Commission may require by rule, or order, that "*all utilities, persons, businesses, or entities connecting to the Hawaii electric system, or any other user, owner, or operator of any electric element that is a part of an interconnection on the Hawaii electric system shall pay a surcharge that shall be collected by Hawaii's electric utilities.*" (Source: Hawaii Revised Statutes, *HI Rev Stat § 269-146 (2017*), 2017).

[17] Ibid.

[18] FERC. Docket No. RR16-6-000. *Order Accepting 2017 Business Plans and Budgets.* Issued October 20, 2016.

[19] Using total electricity production in Hawaii in 2015 of 10,119 GWh multiplied by the average NERC cost per kWh for 2015. (Source: Hawaii Department of Business, Economic Development and Tourism, *The State of Hawaii Data Book: A Statistical Abstract.* 2016.)

[20] FERC. "Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization." Docket No. PL04-16-000. October 2004. P.12.

reliability entity.[21] Using the Texas estimate provided and adjusting for Hawaii size on a $/kWh basis as described above, minimum startup costs can be estimated at $164,293.

4.3 ISO

An ISO or a regional transmission organization ("RTO") is an independent, membership-based, non-profit organization that ensures reliability and uses bid-based markets to determine economic dispatch for wholesale electric power.[22] Under this model, the utilities would still own and rate base their transmission assets, but they would pass the day-to-day operations of the transmission system to the ISO. As discussed in Task 2.1.1, the PUC's oversight on resource planning, power purchase agreements, utility transactions, significant capital expenditure, service quality, and rates would remain the same under the ISO model. However, the ISO would take over responsibilities for reliability and long-term resource planning under this model, with overall oversight by the Commission. The utility's previous role in coordination, scheduling, and dispatch will be transferred to the ISO in this model.

4.3.1 Advantages

The main benefits of an ISO regulatory model are typically bifurcated into quantifiable benefits, i.e., ***efficiency gains of competition*** in the power supply market and ***elimination of subsidies***; and additional benefits, such as ***improved reliability, better coordination, and reduced transaction costs***.

Efficiency gains have been demonstrated in relevant empirical studies that have examined costs to consumers in the years following deregulation and creation of a wholesale power market. In one highly-cited empirical analysis of the outcomes of the PJM market, market participants realized increased gains of over $160 million over the first year.[23] A similar study of the initial benefits of the New York ISO market estimated net annual benefits equivalent to 5% of system-wide production, which is determined to have a value of over $150 million.[24]

The ISO is also responsible for ensuring short-term reliability. Analysis of deregulation in the UK in the 1990s illustrated that incentives created by competitive wholesale electricity networks lead to lower generator operating costs and improved availability.[25] The presence of an independent

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[21] Ibid. p.8-13.

[22] EIA. *Today in Energy*. Website. <https://www.eia.gov/todayinenergy/detail.php?id=790>. Access Date: March 22, 2018.

[23] Mansur, E. & White, M. *Market Organization and Efficiency in Electricity Markets.* January 2012.

[24] Tierney & Kahn. *A Cost-Benefit Analysis of the New York Independent System Operator: The Initial Years*. March 2007. P.39.

[25] Newbery & Pollitt. *The Restructuring and Privatisation of Britain's CEGB – Was It Worth It?* The Journal of Industrial Economics. March 2003.

entity to oversee reliability is particularly important in Hawaii given the state's ambitious renewable energy targets.

Finally, an ISO model reduces conflicts of interest. Transferring the operations of the transmission system to an ISO would lower the conflicts of interest that Hawaii's utilities face under the status quo model. Currently, the utilities own transmission assets but are also responsible over the maintenance of reliability and resource planning. In the said system, the utilities can include transmission assets in their rate base and earn a regulated rate of return on them because they are incentivized to implement solutions that require larger capex spending or favor utility-owned generation assets, to ensure reliability and resource adequacy. With the separation of planning and ownership, the utilities become passive transmission owners and must follow the resource plans endorsed by the ISO and approved by the PUC. The ISO's independence can address the capex bias that investor-owned utilities ("IOUs") have in the current regulatory model.

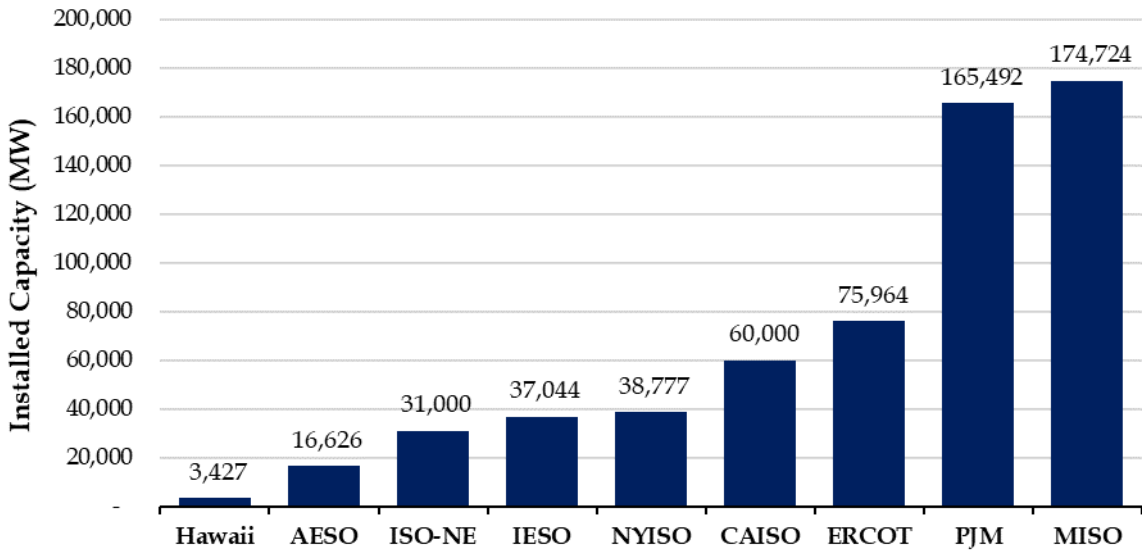
4.3.2 Drawbacks

Admittedly, the ISO model is a ***technically complicated industry structure and requires highly-specialized staff*** to ensure round-the-clock coordination. The costs—in terms of time, effort, and expense—to create, staff, and transition reliably to a new market structure are very significant. All of these additional costs will be borne by ratepayers. In Hawaii, these costs may double as the lack of interconnection among the islands will necessitate multiple markets running independently, all to be coordinated by a single entity.[26] An estimate of the costs of the creation of an ISO (performed by FERC staff) suggested that annual operating costs would impact the average customer by 0.02¢/kWh, with an initial investment of between $50 million and $70 million for hardware and fully operational software (that will calculate available transmission capacity and schedule transmission and dispatch through a centralized control center).[27] The smaller size of Hawaii's electricity system (compared with other jurisdictions with ISOs and RTOs in North America) likely requires higher fixed costs for the creation of an ISO on a per capita or a per kWh basis (Figure 11).

[26] This is currently the case in Mexico, where the state of Baja California is islanded from the rest of the Mexican grid, and as a result, three markets operate in parallel, i.e., the Baja California Interconnected System ("BCA"), the National Interconnected System (Sistema Interconectado Nacional, or "SIN") and the Baja California Sur Electric System ("BCS"). These three markets are monitored by the National Center for Energy Control (Centro Nacional de Control de Energía, or "CENACE"), all referred to as the Mexican Wholesale Electricity Market ("MEM"), which is established as a cost-based short-term energy market with a day-ahead market and a real-time market. (Sources: SENER; IEA, *Mexico Energy Outlook.* World Energy Outlook 2016.)

[27] FERC Staff. *Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization.* Docket No. PL04-16-000. October 2004.

Figure 11. Installed generation capacity in North American jurisdictions



Source: FERC, *Electric Power Markets: National Overview*; IESO, *18-Month Outlook, June 2018*; AESO, *2017 Annual Market Statistics*.

Aside from the smaller size of Hawaii's electricity system in terms of customers served or installed capacity, ***the transmission networks are also significantly smaller***. As described previously on Task 1.1.2, the State of Hawaii has less than 1,900 miles of transmission lines—817 miles in Honolulu County, 622 miles in Hawaii County, 258 miles in Maui County, and 171 miles in Kauai County.[28] Most of the transmission lines also have lower voltage—13.5 kV to 69 kV; only Honolulu County has the higher voltage lines operating at 138 kV. Higher voltage distribution lines operate at 4 kV and 12 kV.[29] Therefore, the distinction between transmission and distribution components of the power delivery system in Hawaii is not as large or as distinct as in the mainland.

Furthermore, as large, aging fossil fuel-fired power plants retire, they are being/will be replaced primarily by smaller renewables-based plants (alongside more efficient diesel units). When combined with increasing levels of DERs, the distinction between transmission and distribution is further blurred. Therefore, the roles of an ISO and a DSO are likely to have more overlap than differences in Hawaii.

The ISO model also requires a ***high level of stakeholder engagement***, which may also increase costs. As noted in Task 2.1.1, an ISO structure aims to assure reliability, which requires collaboration on the part of ISO, utilities (as the transmission owner), generators, and electricity

[28] Task 1.1.2 memo.

[29] HECO. *Power Facts – Power Delivery*. Web. <https://www.hawaiianelectric.com/about-us/power-facts/power-delivery>

utilities. As an example, at the onset of the market in Ontario, the development of the day-ahead market required a three-year transition period and a 12-month testing stage.[30]

ISO models and wholesale markets require ***careful market design*** because a poorly designed market may lead to unintended outcomes such as price spikes and damaged investor confidence. This implementation risk is not insignificant and has been demonstrated to result in inadvertent outcomes, particularly in the event of incomplete reforms.[31]

4.4 Distribution-focused regulatory model

In this model, the regulatory focus is on the optimization of the value of distribution-connected resources or DERs in the electricity value chain. The Project Team has identified a number of potential manifestations of the distribution-focused regulatory model; however, these differences, while outlined briefly here, are not important in our assessment of the regulatory model's strengths and weaknesses. As discussed in detail in Task 2.1.1, the distribution system is still owned and operated by the incumbent utilities under the distribution-focused regulatory model. This model is similar to New York's Reforming the Energy Vision ("REV"), where the distribution utility becomes the **Distributed System Platform Provider ("DSPP")**. The DSPP's new role, as envisioned by the New York regulator, is focused on "planning and designing its distribution system to be able to integrate DER as a primary means of meeting system needs." As indicated in Task 2.1.1, there is currently no jurisdiction that has a full-blown distribution-focused regulatory model.

4.4.1 Advantages

This regulatory model has the ***potential to lower costs*** on the side of consumers as they will tend to shift consumption away from the grid during peak hours by optimizing DER solutions such as storage as well as benefiting from efficiency gains from competition in the DER solution markets. Moreover, ***market efficiencies from increased competition*** would likely result in lower costs. As in any other market, competition motivates players toward technological improvement and product diversification (such as cheaper backup power options) that meet the various needs of consumers.

Furthermore, providing a platform would facilitate greater penetration of renewables and DERs. ***DERs in certain jurisdictions have been observed to reduce distribution grid costs,*** eventually lowering costs on the side of consumers.[32] Benefits from improved coordination may include a

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[30] Dewees, D. *Electricity Restructuring and Regulation in the Provinces: Ontario and Beyond.* September 2005.

[31] Joskow, P. *Lessons Learned from Electricity Market Liberalization.* The Energy Journal. 2008.

[32] In 2014, Consolidated Edison, a distribution utility in New York, projected a shortfall of 69 MW in its feeders for substations in the boroughs of Brooklyn and Queens. As an alternative to a $1.2 billion spending in substations and feeders, the utility proposed and implemented a $200 million DER program, which involved 17 MW of infrastructure investment and 52 MW of demand-side solutions. (Source: New York PSC, *Order Establishing Brooklyn/Queens Demand Management Program.* December 2014. Case 14-E-0302)

reduction in line losses, which can potentially link to a reduction in surplus procurement of generation.

It also provides wider grid access for behind-the-meter generation resources or distributed generation ("DG"). Currently, DG resources in Hawaii are predominantly rooftop solar photovoltaic ("PV") panels. The future sees increasing use of battery-backed rooftop solar energy systems as prices of batteries continue to fall. In the status quo model, the distribution system is operated by vertically-integrated utilities that own both generation and distribution-level infrastructure. They do not have the incentives to support the growth of DG because it lowers sales from utility-owned generation and could reduce the need for distribution-level infrastructure. ***A DSPP would offer more avenues for DG resources to monetize the value they provide to customers and the grid.*** DG owners can sell electricity to the grid or directly to other customers. They may also be compensated for lowering local peak loads, therefore, helping to avoid or defer costly infrastructure upgrades. In New York, Con Edison deferred a $1.2 billion distribution substation upgrade by contracting 52 MW of demand reductions and 17 MW of DERs (including DG).[33]

4.4.2 Drawbacks

Notably, this model leads to ***stranded cost risks inherent in a high DER penetration scenario.*** High DER penetration in the grid may result in decreased network load over time as customers increasingly switch their consumption during peak hours and/or become prosumers[34] in the market. This will likely increase the risk of stranded utility assets—the costs of which will be borne by remaining utility consumers, most of whom may be lower-income customers who are unable to take advantage of the benefits of owning DER technologies.

As described in Task 2.1.1, the distribution regulatory model will require substantial enhanced functional capabilities from the distribution utilities while the complex grid infrastructure required to facilitate it may require ***high-cost investments***.[35] This will also require ***extensive levels of consumer education*** to ensure success. DeMartini and Kristov of the California Institute of Technology and California ISO, respectively, note that the success of this regulatory model requires "*advanced grid platform technologies and operating procedures for the distribution utility to call upon the DERs when needed in real time and track performance*" as well as the development of

[33] Ibid.

[34] Prosumers are both producers and consumers of energy. They have on-site distributed generation behind the meter, allowing them to sell surplus power back to the grid.

[35] Distribution networks typically have very little real-time monitoring and control built into their networks, as these generally have been limited to higher voltage levels and typically used for management of faults, thus extensive transmission upgrades may be required. (Source: Bell, K. & Gill, S. *Delivering a highly distributed electricity system: Technical, regulatory and policy challenges.* Energy Policy 113 (2018) 765-777.)

"methods to identify needs of the system by location, determine hosting capacity, assess potential benefits of DERs on a particular feeder and distribute DERs optimally" within the distribution service area.[36]

To compound these risks, there are not many precedents, therefore, ***few best practices to learn from.*** As described in Task 2.1.1, distribution-focused models are currently at various stages of implementation in California and New York, but few medium- to long-term analyses have been carried out on the impacts of these transitions on utilities and ratepayers.

Finally, as DER penetration increases, the ***possibility for bias and barriers to DER development*** from incumbent utilities could pose risks in the areas of distribution planning, DER interconnection procedures, and real-time operations. As detailed by DeMartini and Kristov, the Commission must remain vigilant as transparency, non-discrimination, and the need to minimize the risk of stranded investment becomes increasingly important due to the diversity of new players entering the DER landscape and the rapidity of changes in technologies and customer demands.[37]

It is worth reiterating that the role of an IDSO would be substantially like that of an ISO in Hawaii. The State's utilities are vertically integrated, unlike in other jurisdictions in New York and Europe with DSPP or DSO models. In such larger and liberalized markets, distribution functions are well-separated from the bulk power system. Other system operators like an ISO or a Transmission System Operator oversee functions such as dispatch, scheduling, reliability, and coordination. In Hawaii, it may be more efficient to have one system operator at both transmission and distribution levels due to the small size of the State's bulk power system. As the proportion of intermittent utility-scale renewables and DERs in Hawaii's power supply mix increases, improved coordination between transmission and distribution will become more critical in the maintenance of reliable grid operations.

4.5 PBR

As discussed extensively in Tasks 2.1.1 and 2.1.2, PBR is a regulatory approach in rate regulation and provides a wide range of mechanisms that can weaken the link between a utility's rates and its unit costs and improve efficiency. Jurisdictions shift to PBR (from the traditional COS or rate-of-return regime) due to several reasons such as lack of incentives under the COS (e.g., features that encourage prudent and efficient capital investment) and weaker incentives for cost-efficiency. Moreover, PBR allows the utility sufficient freedom to decide how to best optimize its resources given the targets and objectives. This is particularly significant for Hawaii in the context of recent legislation and proceedings toward a form of PBR.

The advantages and drawbacks of PBR models can vary based on where a particular PBR design falls (i.e., in the range from light to comprehensive mechanisms). Implementing more comprehensive PBR regulation can yield more profound benefits but at greater risk to both

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[36] DeMartini & Kristov. *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation & Oversight.* Lawrence Berkeley National Lab. October 2015.

[37] Ibid.

shareholders and regulators. A greater proportion of utility revenues or costs are tied to incentives, which lowers the burden to maintain frequent regulatory oversight – more comprehensive PBR models typically also have a longer regulatory period, thus reducing the frequency of rate case proceedings. Utilities are encouraged to pay more attention to their performance with respect to metrics defined by the PUC, driving greater innovation as they seek to improve performance while reducing costs.

The degree of PBR regulation will likely impact costs, feasibility, performance with respect to the six evaluation criteria, and impact on utilities. The Project Team proposes to evaluate three PBR models for future deliverables under Task 2: (i) a "Light PBR"; (ii) Conventional PBR with price or revenue cap, and (iii) Outcomes-based PBR. It is important to note that ***none of the three variants of PBR is objectively "better" than the others as there are benefits and drawbacks to each***. Characteristics of the jurisdiction and objectives of the regulator are essential factors that determine the suitability of different PBR models.

As discussed in Task 2.1.1, **Light PBR** will feature expanded Performance Incentive Mechanisms ("PIMs") with rewards and financial consequences. Hawaii moved toward the establishment of PIMs when the PUC issued *Inclinations of the Future of Hawaii's Electric Utilities: Aligning the Utility Business Model with Customer Interests and Public Policy Goals* in 2014. Currently, the HECO Companies have PIMs for reliability and customer service quality.[38,39] The Light PBR would expand the current PIMs to include other metrics such as reliability, cost control, service quality, customer engagement, competitive procurement, and RPS achievement that align with State policies and energy goals. These PIMs would also be symmetrical, where the utilities would be rewarded for exceeding the targets but also penalized if they fail to meet them. The Team's Light PBR also includes the current earning sharing mechanism ("ESM") and will have the same 3-year general rate cycle.

Conventional PBR would use a revenue cap to determine the revenue requirements of the utilities, restricting their ability to increase earnings. Revenue requirements can only grow based on a pre-determined formula. Conventional PBR can support associated policy goals such as Hawaii's EV targets (e.g., through a price cap regime) and facilitate greater penetration of DERs through revenue caps. Like the Light PBR, the Conventional PBR would also include PIMs and ESM, which has a symmetrical design and increased deadband. Conventional PBR can be designed not just to improve operating efficiency but also address the capex bias that IOUs have through a total expenditure ("totex") approach. A totex approach does not distinguish between capital and operating expenditures, breaking the incentive for an IOU to favor the former over the latter.

Outcomes-based PBR can be considered as the most comprehensive PBR regime. It seeks to incentivize the utility toward beneficial outcomes to society—outcomes that may not be profitable

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[38] Hawaii PUC. *Docket No. 2013-0141. Order No. 34514 Establishing Performance Incentive Measures and Addressing Outstanding Schedule B Issues.* April 27, 2017.

[39] As discussed in Task 2.1.1., utilities are only assessed a penalty for failing to meet reliability targets and not rewarded for exceeding them, whereas the customer service quality PIM features both rewards and penalties.

to the utility under traditional COS regulation. The Project Team identified four potential outcomes: (i) enhance customer experience, (ii) improve utility performance, (iii) achieve public policies and goals, and (iv) healthy financial performance. Moreover, in this alternative, the Project Team would incorporate stringent reporting regimes and require submission of asset management plans to complement the PIMs.

4.5.1 Advantages

PBR mechanisms have some demonstrable advantages over COS regulation. PBR mechanisms have been shown to result in ***improved incentives*** for utilities and can be designed such that they ***drive innovation*** and ***better investment decisions*** from utilities. The PBR approach may reduce administrative and regulatory costs (e.g., due to fewer regulatory proceedings) as well as lead to more stable rates for customers.[40] A well-designed multi-year PBR with well-defined mitigation measures can also reduce regulatory risk on the utility, lowering its cost of debt and, ultimately, in the side of consumers.

Moreover, utilities are ***encouraged to operate more efficiently*** so they can achieve or surpass the productivity targets. PBR can provide strong incentives to increase performance and improve productivity because it allows a utility to derive a significant financial benefit from doing so.[41] This benefit is precisely the incentive that motivates companies in competitive markets to control costs and deliver exceptional service to their customers. The experiences of some jurisdictions that have implemented PBR illustrate its beneficial role in encouraging productivity improvements. For instance, in the case of FortisBC, the regulator, the British Columbia Utilities Commission ("BCUC") noted: "*the Commission Panel is satisfied that there were positive results experienced by both ratepayers and the shareholder over the PBR period. In addition, the Panel finds there is sufficient evidence to suggest that introducing a PBR environment has the potential to act as an incentive to create productivity improvements*."[42] In the UK, Ofgem stated that the PBR regulatory framework has brought benefits to electricity customers over the last 20 years and has "*delivered increased capacity and investment, greater operating efficiency, higher reliability, and lower prices.*"[43] In fact, "*since privatization, allowed revenues have declined by 60% in electricity distribution and 30% in electricity transmission. These reductions have been achieved without sacrificing capital investment, which has continued across all sectors since privatization.*"[44]

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[40] Rate stability under a PBR mechanism is a function of the rate setting formula. Utility rates, typically under an I-X approach will only increase by inflation (I) less the productivity factor (X) plus other flow-through mechanisms. This will be over multiple years, allowing for a longer-term outlook for utility rates. (Source: Olson, Wayne and Caroline Richards. "It's All in the Incentives: Lessons Learned in Implementing Incentive Ratemaking." *The Electricity Journal*: 20-29.)

[41] Sappington, David, Johannes Pfeifenberger, Philip Hanser, and Gregory Basheda. "The State of Performance-Based Regulation in the US Electric Utility Industry." *The Electricity Journal*. October 2001.

[42] British Columbia Utilities Commission. *Commission Order G-44-12*. Reasons for Decision, page 22.

[43] Ofgem. *Regulating Energy Network for the Future: RPI-X@20 Emerging Thinking*. January 20, 2010. P. 50.

[44] Ibid.

Efficiency gains from PBR mechanisms can be shared with customers through ESM. ESM can also lower costs to consumers and ensures effective customer participation in a company's financial performance.[45] In Hawaii, ESM has been implemented along with the Rate Adjustment Mechanism since 2011, as part of the Revenue Decoupling Mechanism approved by the PUC.[46] Through this mechanism, if actual utility returns exceed the PUC-approved rate of return on equity ("ROE"), rates will be lowered to share the "excess" returns with customers. However, utilities cannot use ESM to increase revenues if their actual returns fall below the PUC-approved ROE.

Reliability can also be safeguarded under a PBR regime, especially for plans that have mandated performance standards, which in some jurisdictions also entail a system of penalties and rewards. The presence of incentives provides a strong motivation for utilities to improve their quality of service. Ofgem believed that the implementation of PBR *"has led to significant improvements in quality of service. Between 1990 and 2009, the number and duration of reported outages fell by around 30 percent."*[47] With performance standards in place under a PBR regime, distribution line losses may also improve. In Ontario, line losses of Hydro One decreased steadily for the six years since 2011: by 0.3% on average per year from 1,711 GWh in 2011 to less than 1,625 GWh in 2016.[48]

Moreover, the PBR model could reduce ***administrative and regulatory costs*** in the long term by reducing the number of litigated rate cases for the utility. This is particularly true for the existing Hawaii regulatory framework, where the duration of the rate case application is over 24 months.[49] Reduced regulatory costs under PBR are a result of PBR's recognition of the information asymmetry between the regulatory body and utility. Under COS, regulators spend a considerable amount of time and expense to bridge the information gap.

In contrast, PBR does not try to rectify this information gap. Instead, under the PBR regime, the Commission does not need to know the costs for each O&M item but only the range of possible costs from which the Commission can approve a PBR plan that can elicit maximum efficiency from the utility.[50] Moreover, regulators benefit from PBR to the extent that it eases them out of the demanding task of micro-managing the activities of the utility. For the utilities, reduced

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[45] Sappington, David et al. *The State of Performance-Based Regulation in the U.S. Electric Utility Industry.* 2001. The Electricity Journal. 71-79.

[46] Hawaii PUC. *RAM Legal Notice.* March 31, 2011. <https://puc.hawaii.gov/wp-content/uploads/2013/06/20110427-RAM-legal-ad.pdf>

[47] Ibid.

[48] Ontario Energy Board. *Yearbook of Electricity Distributors (2011-2016).* Accessed at: <https://www.oeb.ca/utility-performance-and-monitoring/natural-gas-and-electricity-utility-yearbooks>

[49] LEI analysis of rate cases between 2009 and 2017 for the HECO companies showed that of the seven (7) rate cases reviewed, three (3) took at least 30 months to decide, while only one (1) was settled in less than 10 months. (Source: Hawaii Public Utilities Commission).

[50] Comnes, G.A. S. Stoft, Green, and L.J, Hill. *Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource Planning Issues Volume I.* November 1995. P. 6.

regulatory micro-management allows them to respond more quickly to technological and competitive challenges. This may mean lower prices for customers.

Additional PIMs under Light PBR can also align the interests of utilities and customers. The utilities, PUC, consumer advocate, and other intervenors are already familiar with and understand how this structure works. This familiarity can lower implementation costs and make it more likely that the utilities can achieve performance targets.

Specifying outcomes regarding customer experience, utility performance, and societal policy goals, among other goals under the Outcomes-based PBR, ***encourage the utility to invest in areas that they may not otherwise***. The ***increased earning opportunities create a revenue driver*** for utilities. Outcomes-based PBR is also typically implemented without necessarily specifying the exact mechanisms that utilities must adapt to achieve the outcomes. This leaves the utilities free to innovate and find a solution that produces outcomes at the lowest possible cost.

Lastly, the Outcomes-based PBR is also the ***most beneficial in advancing specific policy and regulatory goals***. This effectiveness stems from (i) the ability to have outcomes that reflect important public policy goals, (ii) flexibility in terms of offering the utilities a fair degree of leeway in how they can achieve those goals, and (iii) accountability in the regulatory process.

4.5.2 Drawbacks

As noted in Task 2.1.1, moving from a traditional COS to PBR can be a major undertaking not only for the regulator but also for the utilities. It involves a ***significant amount of regulatory work and requires lengthy stakeholdering efforts*** to determine the appropriate PBR mechanism that may be implemented and allow more in-depth analysis of sectoral and technical issues, discussions of which are not always present or as thoroughly dissected during a COS deliberation. This regulatory effort can be driven by ***availability, accuracy, and consistency of data***. Data is often inconsistent or even unavailable because of differing or lack of clear reporting guidelines, varying cost allocation methods employed by each utility, changes, and differences in accounting techniques, and mergers and amalgamations, to name a few. Ensuring data consistency and credibility requires configuring systems and processes correctly.

Sufficiency of capex funding under a PBR approach can be a concern if there are no other capital incentive mechanisms in place other than the indexing formula (inflation less productivity factor) or if the explicit capital incentive mechanism provided is very restrictive. Including a capex mechanism within the PBR formula or, at a minimum, incorporating a feature to reduce regulatory risks associated with capital outlays beyond the control of management may, in fact, provide for increased stability and ensure the longevity of a PBR mechanism.

PBR mechanisms face ***forecasting requirements and challenges*****.** The preparation of PBR filings requires the ability to forecast additional elements that may have been less critical under a COS regime.[51] Forecasting plays a central role in the building blocks approach-based PBR. Poor

[51] Items that need forecasting include load growth, energy growth, depreciation, number of customers, cost of capital, and operating, capital and tax expenditures, to name a few.

forecasting on the side of utilities can also lead to potential additional costs and/or penalties affecting their bottom line. In practice, forecasts can significantly deviate from actual figures so the PBR design must include mechanisms that will provide a degree of protection to both shareholders and ratepayers. These mechanisms may consist of re-openers, ESM, true-ups, rebasing, and flow-through.[52]

Nevertheless, Hawaii can learn from the experiences of jurisdictions that are currently under PBR (both in the US and across the world) on how to manage a transition to PBR in a timely and effective manner.

For Light PBR, identifying appropriate metrics and setting targets can be a challenging task. Some metrics are impacted by many different factors, not all of which may be under the utilities' control. Likewise, an ESM can somewhat increase the administrative burden of PBR because it requires additional effort in determining the earning sharing amount. More importantly, an ESM blunts the efficiency incentives created by the shift to PBR.

The potential drawbacks are also amplified under a more comprehensive PBR regulation. Formulating the details of PBR design is a more extensive and expensive process. The model must be based on rigorous analysis to ensure that the incentive mechanisms can achieve what they are meant to and will not lead to significant unintended consequences. The PUC and regulators both need more accurate data monitoring capability to evaluate performance levels and adjust for the impact of changes (e.g., in weather patterns or macroeconomic conditions).

Finally, a drawback of an Outcome-based PBR is the complexity of putting together a compelling business plan that will justify the utilities' revenue requirements for the 5-year regulatory period. The utilities are also required to submit several documentations such as a detailed plan (that includes their investment and asset management plans) and other documents that support their PBR implementation. Another negative consequence is the additional costs required in the hiring of consultants by both the utilities and the PUC. Generally, consultants are hired to help utilities in putting the PBR plan together and defending it. Consultants who can assist the Commission in the review of the PBR plan and determine whether the proposal is justified are also hired.

[52] In UK, Ofgem developed an innovative mechanism called the menu approach or the information quality incentive ("IQI") to address forecasting challenges in capex and opex. This mechanism provides an incentive to utilities to present reasonable estimates of their true investment needs and penalize them if the information is misleading. It allows utilities to choose an implicit "regulatory contract" that provides the best incentive to declare the most accurate investment plans. Moreover, it rewards utilities with lower expenditure forecasts and provides mechanism for utilities with higher expenditure forecasts to beat the targets by spending less.

5 Evaluation of regulatory models relative to state criteria

The evaluation of regulatory models relative to the State's criteria is both qualitative and high level at this stage of the project. Results are subject to refinement and change as the project proceeds and feedback from stakeholder groups and quantitative analysis become available.

The scoring mechanism is intended as a thought exercise in comparing the various regulatory structures. Each regulatory model was ranked from the most favorable to the least favorable. The scoring does not differentiate between instances in which items were close in ranking versus widely different. It should be noted that this is purely illustrative and may be adjusted in the final report as the results of subsequent stakeholder consultations and analyses become available.

The different regulatory models are evaluated with respect to their ability to address the following state goal criteria, like the criteria used in the ownership models:

i. meet state energy goals, particularly Hawaii's mandated RPS goal of 100% renewable energy by 2045;

ii. maximize consumer cost savings;

iii. enable a competitive distribution system in which a marketplace allows customers and independent agents to trade energy and other evolving services that can meet customer and grid needs;

iv. address conflicts of interests in energy resource planning, delivery, and regulation; and

v. align stakeholder interests.

Aside from the State's goals above, the Project Team is including the sixth criterion to provide a holistic understanding of the transition costs within the context of advantages and disadvantages and provide greater input into the evaluation process:

vi. length and costs of transition to other regulatory models, given current laws, regulatory structure, and organization.

5.1 Ability to meet state energy goals

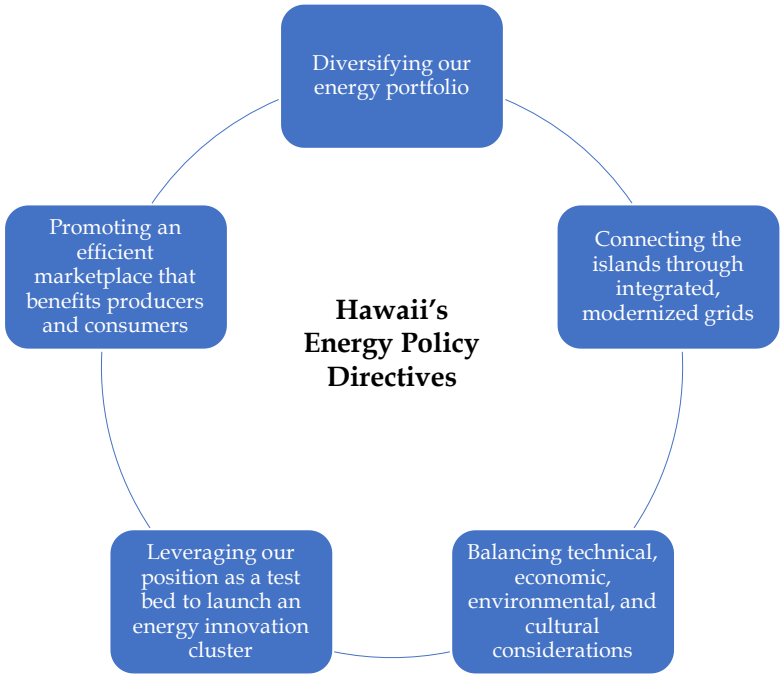
Hawaii has the most aggressive renewable energy targets in the US. It aims to source 100% of its electricity from renewable energy by 2045.[53] Also, Hawaii's energy policy focuses on its "*commitment to maximizing the deployment of cost-effective investments in clean energy production and management to promote the State's energy security*."[54] More specifically, the State aspires to achieve a diversified energy portfolio that makes the best use of land and resources; have an efficient

[53] HI Rev Stat § 269-92 (2015).

[54] HI Rev Stat § 269-92 (2015), Hawaii Senate Bill 198 (December 1, 2011), and Hawaii State Energy Office. Energy Policy. Accessed on July 20, 2017. <http://energy.hawaii.gov/energypolicy>

marketplace that is beneficial to all; create integrated and modernized grids, and be recognized as an energy innovation center.[55]

Figure 12. Hawaii's energy policy directives



Source: HI Rev Stat § 269-92 (2015), Hawaii State Energy Office ("HSEO").

Figure 13. Ability of each model to meet state goals



Source: LEI analysis.

For this criterion, the Project Team focused on Hawaii's target to achieve 100% of its electricity from renewable energy by 2045. The other policy directives (Figure 12) are covered by the other criteria. For example, "balancing technical, economic, environmental, and cultural considerations" is reflected in criteria (v): align stakeholder interests. Likewise, "promoting an efficient marketplace that benefits producers and consumers" is substantially similar to enabling a competitive distribution system.

[55] Ibid; Hawaii House Bill 416 (January 26, 2015), and House Bill 1494 (December 17, 2015).

Hawaii's utilities have made significant progress toward the 100% renewables target under the status quo regulatory structure, where the Hawaii PUC maintains oversight of the State's utilities. In fact, all but one of the utilities are ahead of the current intermediate RPS target of 30% by 2020.[56] HECO had achieved renewables contribution of 20.8% (as of December 2017) but its subsidiaries, MECO and HELCO, have surpassed the 2020 RPS target with RPS of 34.2% and 56.6% respectively.[57] The HECO Companies have a consolidated renewables contribution of 25.8%. Likewise, KIUC has exceeded the RPS target with combined renewable energy and energy savings at 44.4% of net electricity sales.[58]

This indicates that the State's renewable energy goals are potentially attainable under the status quo. All four utilities are vertically integrated and own most of the generation within their territories, with IPPs entering into PPAs with the respective utilities. This centrally controlled structure allows the PUC to push the utilities toward the RPS targets, supported by higher penetration of DERs. The PUC and utilities have encouraged the growth of DERs in Hawaii, particularly rooftop solar [through Net Energy Metering ("NEM")] in the past, and currently with the Smart Export and CGS+ programs.[59]

Keeping the current structure but increasing oversight of the utilities through a new independent agency such as HERA can further support the achievement of the State's energy targets. One of the main challenges with integrating high levels of intermittent renewable energy on the grid is the maintenance of reliability, which is currently overseen by the utilities themselves and monitored by the PUC. Transferring the enforcement of monitoring responsibility to HERA can prevent or at least minimize the tendency of utilities – under the status quo model – to be more conservative than necessary in integrating renewable resources (to maintain reliability Aside from the need to implement reliability standards across the electric value chain, HERA's mandate also includes providing fair grid access to generators.[60] This can open more opportunities for renewable generators and DER providers. Therefore, the Project Team scored increased oversight by an independent agency more favorably than the status quo model.

The PBR model, if well-designed, is considered to be the most favorable in achieving the State's RPS targets because the PUC can set incentives and penalties explicitly based on progress towards pre-established goals such as "rapid integration" of renewables (including third-party home solar

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[56] HB 623 HD2 SD2 CD1, *Relating to Renewable Standards.* House of Representatives, Twenty-Eight Legislature, 2015. State of Hawaii. Web. Accessed May 10, 2017.

[57] Hawaiian Electric Company. *2017 Renewable Portfolio Standard Status Report.* February 8, 2018.

[58] Kauai Island Utility Cooperative. *2017 Annual Renewable Portfolio Standards Status Report.* March 29, 2018.

[59] The Smart Export and Customer Grid Supply + ("CGS+") programs allow customer sited solar generation to supply power to the HECO companies at fixed rates. The Smart Export program allows up to 3,500 to 4,500 customers to export energy through their solar-battery system to the grid during evening, overnight, and early morning (i.e., 4:00 PM to 9:00 AM) following charging during the day. The CGS+ program allows approximately 5,000 to 6,000 customers with solar PV-only systems to export energy to the electric grid during the day (Source: Hawaii Public Utilities Commission).

[60] Hawaii Senate Bill 2787 (2012).

and storage systems), affordable rates, electric reliability, and customer choice and satisfaction (specific PBR metrics can be set for any of these criteria). The PBR model scores very favorably because it enables a "carrot and stick" approach that can be designed to both encourage utilities to achieve targeted performance and penalize them for underperformance. It also allows the utility freedom in optimizing its resources given targets and objectives.

The ISO and distribution-focused regulatory models both score less favorably than the status quo because they fail to address incentives at opposite ends of the generation spectrum. The ISO model can facilitate the development of significant renewable projects by increasing competition at utility-scale. As an independent body, system planning conducted by an ISO would also level the playing field between generators and allow renewables to compete based on cost and value to the grid. On the other hand, an ISO model without new initiatives at a distribution level will not substantially expand opportunities for DERs to participate. Conversely, a distribution-focused model can support the growth of DERs by unlocking additional value for them by incorporating them into distribution-level planning, allowing them to provide grid services and facilitating direct transactions with other customers. However, such a model does not address generation (at utility-scale), which accounts for most of the generation.

5.2 Maximize consumer cost savings[61]

Hawaii's customers already pay the highest rates for electricity in the US. The average electricity price across all sectors in 2016 was 132% higher than the national average and 33% higher than the next most expensive state, Alaska.[62] Ratepayers bear several categories of costs that are impacted by regulatory structures, including (but not limited to): (i) power supply including fuel costs; (ii) other utility operating costs; (iii) costs of regulatory proceedings; (iv) fees to fund regulatory bodies such as PUC (and HERA, if implemented); and (v) return on capital investments.

Regulatory models can lower the costs faced by customers if they can support the development of lower cost resources for generation, reduce reliance on expensive imported oil, incentivize the utility to be more efficient and cost-effective in its operations, lower the regulatory burden (including the length of typical regulatory proceedings), or reduce the bias for utilities to favor capital expenditure ("capex") for higher returns.

The PBR model is regarded as the most favorable in terms of reducing costs to consumers in the long run because it can incorporate incentives to control costs under both price- and revenue-cap approaches, while still maintaining service quality as well as other parameters set by the PUC (Figure 14). It can also set incentives that de-emphasize the importance of returns on capital investments for utilities' profitability. Indeed, in its order instituting the PBR proceeding, the PUC outlines its interest "in ratemaking elements and mechanisms that result in:"[63]

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[61] The consumer cost savings considered in this section excludes consideration of implementation costs.

[62] EIA. *Electric Power Annual 2016.* Revised May 2018.

[63] Hawaii PUC. *Docket No. 2018-0088 Instituting a Proceeding to Investigate Performance-Based Regulation.* Order issued and effective April 18, 2018. page 52.

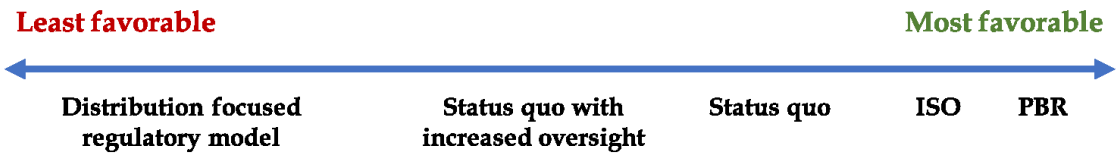
- greater cost control and reduced rate volatility; and
- efficient investment and allocation of resources regardless of classification as capital or operating expense.

It is important to note that establishing PBR will initially require time and impose a sizable regulatory burden on both utilities and the PUC, the costs of which will be passed on to ratepayers. However, once implemented, this model can achieve reductions in multiple categories of costs, creating higher savings for consumers in the long run.

An ISO model can also lower costs of the power supply by increasing competition in generation. Likewise, independent transmission planning and operations can lower system-wide costs. It also addresses utility bias towards capex, at least at the transmission-level, because utilities will make investments based on the ISO's planning. This is a more favorable environment for lowering costs to consumers than the status quo, where the utilities have no incentives to minimize costs due to the cost of service ratemaking regime. Costs to consumers are controlled in regulatory proceedings, such as rate cases, by the PUC and the Division of Consumer Advocacy ("DCA"); however, COS regulation has been observed to provide an incentive for utilities to overstate capex (to increase returns on investments), subsequently and possibly resulting in higher costs.

The regulatory burden only increases for both utilities and HERA in a HERA model. To comply with regular reporting requirements, utilities will have to monitor and track various metrics on reliability and grid access. Furthermore, HERA will have to be staffed with trained personnel to enforce standards and ensure utility compliance. There will also be an additional reliability surcharge on ratepayers to fund HERA.

Figure 14. Ability of each model to lower costs to consumers



Source: LEI analysis.

A distribution-focused regulatory model is the least likely model (at present) that can reduce costs (in the short term) to consumers. Such a model requires extensive investment in grid-modernization technologies. Some of the technologies needed for a fully-fledged version of this model have not been operationalized outside of pilot tests. The enabling technologies, both hardware, and software, may improve capability and become cheaper over time. The full costs of transition to a distribution-focused model are largely unknown, but they are likely to be high based on prevailing market conditions. These costs will eventually be passed on to ratepayers.

5.3 Enable a competitive distribution system

A competitive distribution system is one "in which independent agents can trade and combine evolving services to meet customer and grid needs."[64] This goal requires the evolution of grid operations and services away from the traditional utility business model where the utility has a monopoly over the sale of electricity and other limited services to the customer. The traditional regulatory models are not as favorable for a competitive distribution system as more innovative ones.

The status quo model offers programs like Smart Export and CGS+ to expand rooftop solar and battery storage. However, this approach limits the competitiveness at the distribution level because the utility remains the sole buyer of electricity from distributed generation, excluding any separate bilateral contracts between independent parties. Technology providers can offer their services to utilities as well as customers. Utilities increasingly partner with third-party companies especially for their need for software and other services that support grid management. For example, HECO is using Opus One's GridOS Dynamic Hosting Capacity software to understand how much DERs can be integrated into a distribution feeder to better optimize grid assets in real-time.[65] Customers can also purchase products and services (like the Nest thermostat and similar home energy management systems) from third-parties. However, such opportunities for customers and other market participants are defined by the utility through scope, requirements, and rates.

Adding increased oversight is slightly more favorable than the status quo model. Independent planning by an entity such as HERA can address the tendency of utilities to limit the participation of DERs and service providers, for example, by using excessively stringent criteria. HERA's responsibility to oversee grid access can ensure that grid-services provided by DERs[66] are integrated into planning without impacting reliability.

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[64] Hawaii Contract No. 65595. Scope of Services.

[65] "Hawaiian Electric and Opus One Collaborate on Grid Modernization." *Opus One Solutions*, 18 April 2018. Web. Accessed on May 17, 2018. <www.opusonesolutions.com/news/hawaiian-electric-and-opus-one-collaborate-on-grid-modernization>

[66] According to a survey of literature on benefit-cost analyses of behind-the-meter resources conducted by eLab, DERs can provide grid support services (in addition to energy and capacity) such as reactive supply and voltage control, regulation and frequency response, energy and generator imbalance, and synchronized and supplemental operating reserves.

The ISO model is regarded as more favorable than the status quo models because it enables greater participation of DERs at the wholesale level. For example, FERC Orders 745 and 841 have opened additional opportunities for demand response and energy storage to participate in wholesale markets and be compensated appropriately in other North American jurisdictions. Under the ISO model in other jurisdictions, DERs can compete with generation and even transmission upgrades in meeting system needs.[67] Utilities in markets with an ISO have begun to deploy DERs as Non-Transmission Alternatives ("NTA") to defer or even replace the need for transmission upgrades. The independence of ISOs is important to ensure that the competition is not biased in favor of utility-owned generation or new transmission projects with high capex.

Likewise, the PBR model can be more favorable than status quo models because of the incentives and penalties that can be designed based on the criterion: increasing competition at the distribution level. New York is pursuing a version of this by soliciting innovative solutions by various features including Advanced Metering Infrastructure ("AMI") network access, customer response to smart home and time-of-use rates, Energy Marketplace 2.0, increasing hosting capacity, reducing peak, and Non-Wires Alternative ("NWA") projects.[68] Incorporating Earnings Adjustment Mechanisms ("EAM") in the PBR mechanism can be favorable for a competitive

Utility financial incentives in NY's REV

Currently, the utilities in New York can receive incremental performance incentives for achieving REV objectives through Earnings Adjustment Mechanisms ("EAM"). There are currently five EAM opportunity areas:

- **System efficiency and peak reduction** – improve overall system efficiency to reduce capital investment, including peak reduction and load factor improvement;
- **Energy efficiency** – support greater overall energy efficiency savings and the transition to market-based approaches;
- **Interconnection** – improve processes for the interconnection of DG projects, as measured by a DG developer;
- **Customer engagement** – increase customer uptake in specific innovative programs; and
- **Greenhouse gas reduction** – support the electrification of transportation, building heating and cooling, reduce the cost of achieving New York's goal of getting 50% of electricity from renewable sources by 2030.

Source: NY REVConnect. *Track Two: REV Financial Mechanisms.*

[67] Only California's market, operated by CAISO, allows aggregate DERs to participate in the wholesale market, in both the energy and ancillary service markets. This take the form of a DER provider ("DERP"), a market participant allowed to aggregate DERs to meet the 0.5 MW requirement to participate. Examples of DERs that can participate under this market arrangement include generation such as rooftop solar PV, energy storage, plug-in electric vehicles ("EV"), and demand response (Source: CAISO. *Distributed energy resource provider.* <http://www.caiso.com/participate/Pages/DistributedEnergyResourceProvider/Default.aspx>)

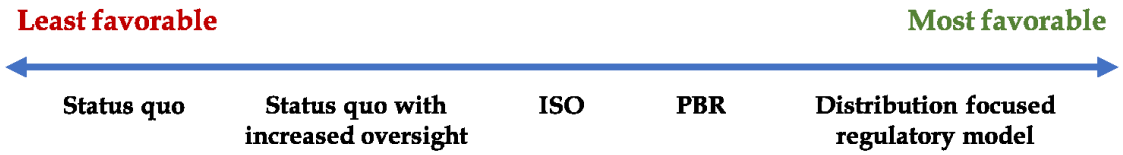
[68] "Innovation Opportunities." *REV Connect*, Accessed on May 17, 2018. <nyrevconnect.com/innovation-opportunities/>.

distribution system because utilities have incentives to increase participation of third-party service providers. The textbox provides an example of the EAMs in New York.

The EAMs and solicitation of innovation opportunities, as designed in New York's REV, may help align utility incentives and increase competition at the distribution level. However, it retains a centralized approach to procurement, which could undermine initiative and creativity. New York's efforts with NWA programs and EAMs are considered transitionary steps toward a fully-fledged distribution-focused regulatory model, conceptualized as a DSPP.

A DSPP or IDSO model can be the most effective model in enabling a competitive distribution system because customers, DER providers, and service providers can transact with each other in the future under this model without the utility serving as an intermediary or defining solicitation criteria (Figure 16). Compared with other regulatory models, a distribution-focused model allows buyers and sellers of energy and other services to interact directly with each other. Such increased transparency can encourage more participation in distribution markets. In New York, utilities can earn platform service revenues, which are tied to the selling of products and services that facilitate distribution-level markets, shared revenue opportunities, and other options for customers (such as the ability to pay a fee for value-added services such as advanced data analytics).[69] If a similar mechanism is instituted in Hawaii, utilities would have a stronger incentive in facilitating the growth of distribution-level markets than under a PBR model.

Figure 15. Ability of each model to enable a competitive distribution system



5.4 Address conflicts of interest

Conflicts of interest can take place between and among utility shareholders, ratepayers, regulators, and market participants like IPPs and DER providers in matters of energy resource planning, delivery, and regulation. Addressing conflicts of interest requires as much separation of planning and operational control from investment and ownership as possible. The performance of various regulatory models in addressing conflicts of interest has been discussed in the previous three criteria and will be summarized again in this section.

The status quo model is the least favorable because the PUC is the sole entity responsible for addressing or managing conflicts of interest (Figure 16). The utility maintains full control of energy planning and delivery with PUC oversight being the only check. This means that there is information asymmetry between the utility and the regulator, i.e., only the regulator has access to as much information on the utility's actions as the utility provides. Increasing oversight with HERA can help spread the regulatory burden between agencies. The independent planning can

[69] Ibid.

also help address utilities' potential conflict of interest against IPPs and DERs, for example, by separating some of system planning functions. A PBR model can use incentives and penalties to align the utilities' business models—a step, which helps in guarding against or managing conflicts of interest—but it will not result in full separation of planning and operational control from investment and ownership. Such a separation is achieved by a distribution-focused regulatory model at the distribution level and an ISO model for the transmission system and utility-scale generation. Combining both an ISO and a DSPP/IDSO model would be most effective in addressing conflicts of interest.

Figure 16. Ability of each model to address conflicts of interest



5.5 Align stakeholder interests

This criterion—alignment of stakeholder interests—is similar to the previous one but with more focus on whether stakeholder interests are aligned rather than whether conflicts can be resolved. The status quo model is, again, the least favorable because the utility's interests are in increasing profits (ultimately through rates) and making stakeholders happy whereas ratepayers want to keep their electricity rates low (Figure 17). This conflict plays out through other channels as well. Ratepayer interests favor greater participation of DERs and IPPs to keep their costs low. This would harm utilities' profitability unless they could increase capex in grid modernization infrastructure to accommodate more DERs—a step, which negates the cost-reduction value of DERs. Increasing oversight of the status quo along with the accompanying independent planning could better align interests between ratepayers and utilities.

A distribution-focused regulatory model is more favorable than the other models in this criterion because utilities are focused on providing the necessary level of distribution infrastructure. An independent DSO is perceived as fairer than the status quo utility because it has no incentive to increase its profitability beyond what is necessary to keep it financially healthy. Likewise, the ISO maintains similar independence in transmission planning and operations—a feature, which would help increase competition in utility-scale generation. Furthermore, ISO or DSO would both align the interests of ratepayers, utilities, and market participants.

However, a PBR model, if designed correctly, is the most favorable of all the regulatory models in this parameter because there are multiple avenues, where stakeholder interests may be aligned (e.g., through incentives). Incentives based on shared savings can be designed to both decrease capex spending and increase operational efficiency, resulting in lower rates while aligning interests with the utility. Likewise, other incentives based on RPS achievement, DER interconnection, and similar programs benefit both ratepayers and utilities. The incentives and penalties in a PBR model are determined in regulatory proceedings in which stakeholders can intervene, allowing both ratepayers and utilities to provide their inputs.

Figure 17. Ability of each model to align stakeholder interests



5.6 Process and costs of transition

The additional criterion proposed by the Project Team is the transition cost. Section 5.2 compares the regulatory models based on cost savings for consumers *after* the transition has been completed. It is essential to look at the steps needed to move to a new regulatory model to understand the level of opposition and delays that the process may encounter, all of which can substantially increase the transition costs. Task 2.3.1 will discuss this in detail. The more stakeholders involved in the transition process and the more approvals required likely indicates a greater probability of delays. Likewise, it is important to consider if a new regulatory model will require divestment of assets by the utility. This can increase the opposition of the utility and increase the likelihood of an expensive litigation process as well as an increase in the timeframe required to sell assets.

Maintaining the status quo would require no changes; adding increased oversight will likely be the next best option in terms of transition costs and timeframe (Figure 19). The law that requires the establishment of HERA already exists through state legislation (Act 166) in 2012. There will still be costs in setting up HERA as a functioning organization. The PUC is authorized to contract with a person, business, or organization (except a public utility) for the performance of HERA's functions.[70] Therefore, it must set the requirements for interested entities and run a competitive solicitation. Furthermore, there may be additional costs in hiring the personnel with the necessary expertise and/or providing additional training to the new staff. While this process must be conducted thoroughly, there are no glaring pitfalls that could result in lengthy stakeholder outreach or expensive litigation.

Compared to the move to a HERA model, the move to a PBR model could be a lengthy and expensive process, especially during the first regulatory period, despite the recently enacted legislative mandate. PBR has several "flavors"—ranging from "soft" to "hard" mechanisms—and involves price- vs. revenue-cap approaches (as discussed in Task 2.1.1.). Moreover, several criteria can be linked to performance targets. The exact combination of various components of PBR can result in substantially different incentive/risk profiles and revenue opportunities for the utility. For first-generation PBR, there will also be costs related to the hiring of external consultants and experts (who can provide guidance on designing PBR proposals) by both the PUC and utilities. The length of the process for deliberation (e.g., between proposed PBR models), incorporation of stakeholder feedback, and finalization of the ultimate design could take between several months to more than a year.

[70] HRS 269-147.

An ISO model is even less favorable in terms of transition costs because it requires the actual purchase of physical equipment in addition to the establishment of a new organization. First, there may be a need for legislation (toward the creation of an ISO) after due process and deliberation. This can be a lengthy process itself due to the need for extensive stakeholder engagement. There must also be a clear demarcation of authority between/among the new ISO, utilities, and the PUC.

In addition, the establishment of the organization requires defining of clear governance structures, the hiring of appropriately qualified staff (both from current utilities and externally), and the establishment of the office. It will require separate premises and office infrastructures such as computers, IT infrastructure, and furniture (some of which might come from the utility and some purchased). The specific software and equipment used by the current utilities for system planning, dispatch, and day-to-day operations can be obtained from the utilities themselves.

The distribution-focused regulatory model is regarded as the least favorable due to the extent it varies from the current utility business model, the infrastructure needed to enable it, and the degree of unknown costs. As with the ISO model, legislation that supports the move to a distribution-focused model should first be passed, but such a law requires an extensive stakeholder engagement process. However, while there are several examples of well-functioning ISO markets, the same cannot be said of a DSO or DSPP market.

Figure 18. Relative performance of each model with respect to transition costs



There are several jurisdictions moving towards different versions of such a model, but they are still in transition. A move towards this model will require extensive levels of new customer- and grid-facing technologies, some of which have not yet been deployed commercially outside of pilot projects. The full cost of such enabling infrastructure is currently unknown but likely to be high. In New York, preliminary investments in enabling technologies and pilot programs for DSPP development range between $11 million and $190 million between 2017 and 2021, depending on the technology, utility service area, and current status of utility infrastructure.[71] Moreover, this model may require the utilities to divest their generation or at least separate them into an unregulated subsidiary, depending upon the exact design and implementation. This can make the process much more complex and even more expensive because Hawaii's utilities are still vertically-integrated unlike in other jurisdictions that are moving toward a distribution-focused regulatory model.

[71] From Task 1.1.4 memo.

6 Potential hybrid regulatory models

The discussions in the previous chapters demonstrate that each regulatory model carries its own set of advantages and disadvantages and performs differently in the six evaluation criteria. Excluding the sixth criterion, i.e., the process and costs of transition, the Project Team's analysis considers the PBR model to be most favorable in meeting three of the five criteria. The distribution-focused regulatory model was considered most favorable in its ability to achieve a competitive distribution system, and both distribution-focused regulatory and ISO models were regarded as most favorable in addressing conflicts of interest (Figure 19).

Figure 19. Most favorable model for each evaluation criterion

Criteria	Most favorable model
Meet state energy goals	PBR
Lower costs to consumers	PBR
Enable a competitive distribution system	Distribution focused regulatory model
Address conflicts of interest	ISO/Distribution focused regulatory model
Align stakeholder interests	PBR
Minimize process and transition costs	Status quo

The preliminary analysis shows that the PBR model is the most effective model overall. However, the regulatory models described here are not necessarily mutually exclusive. This is especially true of the PBR model, which can be designed to be effective alongside an ISO, a DSPP/IDSO, or under additional HERA oversight. Based on Figure 19, combining PBR with both an ISO and a DSPP/IDSO could even be more effective in meeting the State's goals (except transition costs).

6.1 Conventional PBR + Light HERA

A combination of the Conventional PBR and a Light HERA could be able to help achieve most of the state goals discussed in the previous section. More specifically, this hybrid model could lower costs to consumers in the long run due to the indexing formula of the Conventional PBR. Since revenues are fixed, utilities are incentivized to be more efficient in their expenditures while still achieving their mandated targets. Combining this with the Light HERA will also lower costs as the HERA entity will provide a fair interconnection process, where third-party power providers can compete with the utility in offering the most cost-effective solutions.

This could also enable a competitive distribution system as HERA manages the DER interconnection process in a fair and transparent manner. Adding Light HERA to the regulatory regime would simplify the monitoring of the DER interconnection process (including associated reliability and hosting capacity analyses) by moving these tasks to an independent body. DER interconnection requests would be prioritized based on how beneficial they are to the overall grid not just to the utilities' bottom line. Moreover, conventional PBR with revenue caps can encourage utilities to support the growth of DERs. However, the incentives to do so would predominantly apply in cases where utilities can lower their costs by deploying or directly owning DERs.

Conflicts of interest will also be minimized or reduced because HERA functions as an independent appeals body that can help settle differences. The combination of the Conventional PBR and Light HERA aligns stakeholder interests because PIMs can be designed to address stakeholders' concerns. Process and transition costs can be lower in the long run. For instance, there will be fewer rate filings because of the fixed PBR regulatory term, and litigation process that allows HERA to act as the ombudsman tasked to assist in settling differences between the utility and customers (e.g., on issues related to interconnection and hosting capacity).

The Light HERA entity also frees up the utilities' resources, so they can focus primarily on improving efficiencies and lowering costs. This has the potential to deliver the more significant benefits that are usually found in the Conventional PBR model. Moreover, both components of this combined regulatory model are already being implemented in other jurisdictions. Therefore, lessons learned from their experience can be considered in designing these regulatory models. The different mechanisms with which it has been implemented are detailed in Task 2.1.1. Likewise, there is already legislation for a HERA in Hawaii; no further legislation would be required for a Light HERA entity.

6.2 Outcomes-based PBR + DSPP + Independent Grid Operator

Another combination that could achieve most, if not all, of the state goals, is the combination of an Outcomes-based PBR, DSPP, and ISO/DSO.

As mentioned earlier, given the smaller size of Hawaii's transmission systems (compared to jurisdictions elsewhere), the Project Team believes that combining the functions of the ISO and independent DSO is more effective and efficient in the Hawaii context. For this Project, we will call this combined ISO and DSO as Independent Grid Operator ("IGO"). The responsibility of planning and operations, including the dispatch of both the transmission and distribution system, falls to the IGO. It will also determine the investment requirements of both transmission and distribution networks. The utilities will continue to own the transmission and distribution assets, but the operations will be under the IGO.

There are examples of entities that combine traditionally separate roles and functions. For example, in Singapore, the Electricity Market Authority ("EMA") combines three disparate functions: as (i) power systems operator; (ii) industry regulator; and (iii) industry, developer.[72] As a system operator, EMA also conducts system planning to ensure reliability—such planning includes incorporating distributed generation (along with large generation plants) into the power system. This synchronizes well with EMA's functions as a regulator—functions that involve promoting competition and ensuring resource adequacy.

The role of the utility would also evolve into that of a DSPP. Under the IGO's oversight, the utilities can establish guidelines for DERs and other service providers so that they can offer grid support services. Utilities can then run competitive solicitations for these services and would only be allowed to provide these services themselves if third-party providers failed to beat the utilities' cost benchmarks. The IGO's independence will help ensure that the evaluation criteria for such

[72] Energy Market Authority. *Our Roles.* Web. <https://www.ema.gov.sg/Our_Roles.aspx>

solicitations will not be designed to deliberately favor any potential offeror, including the utility. Utilities and IGO can devise a compensation scheme for these services such that ratepayers would bear lower costs compared with instances (under the previous model) when they rely on traditional utility solutions (such as infrastructure upgrades). Utilities will also be allowed to earn additional revenues, either as shared savings from avoided costs to ratepayers or as fees from the third-party providers ("platform revenues," for example).

The components of this hybrid model can be implemented in different stages. The hybrid regime will feature Outcomes-based PBR initially—the IGO's functions such as the overseeing of reliability and interconnection and the DSPP's role in leveraging DERs for grid services (to lower costs to ratepayers) can be incorporated as outcomes and metrics within the PBR framework. When the IGO is introduced, reliability and interconnection targets can be removed from utility ratemaking. It may be prudent to add the DSPP component last, or at least not before the IGO, as it is the most complex component and the intervening years can shed more light on the enabling technologies and business models.

Indeed, it may even be more advantageous to implement such a combined model. The proposed hybrid model will likely ***be more effective in meeting the State's goals.*** It will be more effective in enabling a competitive distribution system and addressing conflicts of interest than just a "pure" PBR model. Furthermore, ***fewer incentive mechanisms would be necessary under such a hybrid model*** because the IGO and the utilities' role as a DSPP would make it unnecessary to include incentives (such as for those related to reliability, DER interconnection, or competitive procurement) for the utility. In such a scenario, the proposed IGO would likely address those criteria by its independence and mandates. Therefore, the focus of the incentives under PBR can be directed to where they will be most effective, for example, on lowering costs and aligning the utility's incentives with the State's energy goals.

A staggered implementation can also help lower the transition costs of this hybrid model and make them more predictable. The costs of a DSPP model will be better understood because lessons from other jurisdiction regarding implementation, technology, and business models can be adapted to Hawaii. There is more time to conduct the necessary analyses, so the State can fully understand all costs and benefits and ensure that it is implemented correctly. The additional time can also allow the completion of any needed legislative processes.

A significant downside is a potential need to pass legislation and regulations, to create the mandate and authority for such a new entity unless the parties can voluntarily reach an agreement.

7 Lighter regulation for KIUC

Electric cooperatives ("co-op") such as KIUC are owned by their customers, who are also referred to as "members" of the co-op. On November 2002, KIUC became the first electric co-op in Hawaii when it purchased the electric assets on Kauai from Citizens Communications. Any individual, partnership, joint venture, corporation, limited liability company, political entity, or other person or legal entity that has agreed to purchase or purchases electric energy from KIUC is eligible for membership in the co-op.[73]

KIUC's decision-making process is indirectly controlled by its members through the Board of Directors, who are elected by the members on a "one member, one vote" basis.[74] Candidates receiving the highest number of votes from members during the voting period for the number of positions being filled will be declared as elected regardless of the number of votes cast. Tie votes are decided by a coin flip conducted by a Circuit or District Judge. In the most recent board members election, three seats were vacant, with six nominees, one of whom was nominated by petition. The winning nominees were selected with a 19% voter turnout and the petitioned nominee finishing fourth.[75]

The co-op members' equity interest in KIUC and their ability to hold KIUC's leadership accountable theoretically helps ensure that KIUC's decisions reflect the interests of most voters. Therefore, the following two of the six criteria used to evaluate the various regulatory models are not as relevant to KIUC:

- Maximize consumer cost savings – KIUC members' ownership stake in the utility and their voting rights already provide the potential for oversight of KIUC efforts toward a cost-minimization approach in planning and operations.

- Address conflicts of interests – any profits generated by KIUC are returned to its members in the form of patronage capital and efforts in resolving the conflict of interest that usually exists between utility shareholders and ratepayers in IOUs. Likewise, KIUC has less incentive to discriminate against IPPs if they are competitive with utility-owned generation. However, it must be noted that the co-op model may not itself provide oversight of conflicts of interest within its management.

While the other IOUs remain in compliance, it is noteworthy that KIUC is currently ahead of the IOUs in meeting state energy goals. As mentioned in Section 5.1, KIUC achieved 44.4% of net electricity sales from renewable energy and demand-side management in 2017; the corresponding

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[73] Kauai Island Utility Cooperative. *Seventh Revised and Restated By-Laws of Kauai Island Utility Cooperative.* Accessed at: <http://website.kiuc.coop/content/bylaws> on June 13th, 2018.

[74] KIUC. *About Us – Cooperative Principles.* Web. <http://website.kiuc.coop/content/cooperative-principles>

[75] Note that candidates are nominated by a Nominating Committee, that is chaired by a sitting Director, not due for re-election. Candidates can also be nominated by petition, via submission of a petition signed by 35 KIUC members in good standing. (Source: Kauai Island Utility Cooperative. *KIUC Board Election Results.* March 2018. Accessed at: < http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/pr/pr2018-0310-election.pdf>)

proportion for HECO Companies was 25.8%. KIUC has committed to further expansion of its portfolio of renewables so it can reduce the fuel costs of its oil-fired plants. As of 2016 (the most recent year for which complete data is available), KIUC's residential customers paid the highest rates relative to other counties, with average rates of 34¢/kWh in 2016. This is compared to 26¢/kWh paid by HECO residential customers, the lowest among the HECO companies.[76] Provided Kauai County residents share the state policymakers' desire to transition to renewable energy; they can also pressure the KIUC leadership to continue expanding the penetration of renewables.

As described in the Task 2.1.1 report, the lighter regulation model will relieve KIUC of the requirement to obtain PUC approval for rates and rate design, contracts with fuel and power suppliers, and capex. Under lighter regulation from the PUC, KIUC would be exempted from certain regulations—such as those for approval of rate setting and design, power purchase agreements with IPPs, fuel contracts, and large capital expenditures—established based on an IOU structure, if such transactions or activities would not exceed particular thresholds.

However, such thresholds regarding rate increases and capital expenditures would be put in place to trigger a review by the PUC. Specific triggers could be designed to reinstate PUC's regulation, e.g., for projects or rates above a certain threshold or customer disputes above a certain amount. However, the exact metrics must be developed carefully. An indicative approach to the development of triggers could include, but are not limited to:

- Seeking of approval if KIUC wishes to pay a salary higher than HECO Companies for any similar position;
- The opening of PUC investigation in the following events (or similar cases):
    - When rate increases exceed the higher of 5% or 2 times State consumer price index ("CPI"), and 5[x] or more ratepayers object to PUC, PUC may open investigation;
    - If ratepayers provide evidence of rate discrimination; and
    - If the customer has exhausted KIUC internal dispute resolution processes and continues to feel KIUC has acted contrary to their policies, PUC guidelines, or the State law.

KIUC's Board of Directors would continue to approve operating and capital budget, develop resource plans—considering the interest of the members and ensuring adequacy of electricity. The Board's decision-making, however, would be subject to protest and would trigger a review if they are deemed to violate cost causation principles. Similarly, protections would remain in

[76] Sources: HECO Companies website. *Rates and Regulations – Average price of electricity.* Website. <https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/average-price-of-electricity>; KIUC. *"KIUC Miscellaneous Data 2012-2016." Annual Report to the PUC (December 31, 2016).* PDF page 47.

place for any perceived self-dealing and severe deviation from accepted management practices. Moreover, the state energy goals will still apply to KIUC.

The most significant benefit of a reduced oversight model is cost savings for KIUC. Regulatory proceedings are expensive and can extend for more than a year. KIUC must commit personnel to prepare materials for filings, engage with stakeholders, and hire outside consultants on legal and financial matters. For example, during rate cases, the costs to KIUC can be more than $3 million a year or over $81 per customer per year.[77] Without the direct PUC oversight, the utility can prioritize its resources and savings can be passed down to KIUC members instead.

A reduction in regulatory burden can increase operational flexibility for KIUC. Currently, KIUC requires PUC approval before it can introduce new rate designs or even raise rates. Given the costs of a rate case, it may refrain from filing with the PUC even if doing so may benefit both the utility and its members. Reducing PUC's regulatory requirements for KIUC allows the co-op to introduce innovative programs and rate designs if its board approves them.

A significant drawback of this model is that it becomes more challenging to align KIUC's corporate direction with state policy goals. KIUC's members and board both agree with Hawaii's 100% renewables target, but this may change in the future (however unlikely that may appear at present). Hawaii's legislature may also introduce other policies in the future that are relevant to electric utilities—policies such as targets for battery storage and electrifying transportation or regarding charging infrastructure for electric vehicles. A lack of direct PUC regulation will leave state authorities with fewer tools at their disposal to ensure that KIUC will comply with their policy goals.

This scenario is currently unfolding in a Virginia co-op. Members of the Rappahannock Electric Cooperative have filed a petition against their co-op with the Virginia State Corporation Commission. Their dissatisfaction stems from bylaws—adopted by the co-op's board of directors—that they believe are inconsistent with the co-op's founding principles.[78] While the complainants are in the minority, the incident illustrates an example of the need for external oversight for a co-op board.

The PUC also plays the role of a mediator if KIUC's members are dissatisfied with the utility leadership. While members can raise matters with the board and trigger an election, they may still be out-voted. Similarly, the absence of PUC oversight may result in the principal-agent problem, where management engages in self-dealing. This includes the incentive for top management to award themselves high salaries, cronyism for jobs, and rate design that favors strong lobby constituents or rate classes. In such cases, they will have no recourse without PUC regulation. As an objective body, the PUC is well-suited to mediate in disputes over rates or other policies that disproportionately harm a minority of KIUC members.

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[77] Project Team's meeting with Ben Sullivan and Hermina Morita on Kauai Island. June 15, 2018.

[78] SNL. "Va. Co-op members file legal challenge in fight for control" July 27, 2018. Web. Accessed August 5, 2018.

Another factor is the PUC's reliance on fees—from Hawaii's utilities—to meet its overhead expenses. PUC fees will presumably be waived for KIUC if the latter is removed from the former's regulatory authority. Currently, utilities are charged 0.5% of gross annual revenues for PUC fees.[79] KIUC's gross revenue was $147.8 million in 2017, resulting in estimated PUC fees of about $0.74 million.[80] This would be a small but significant loss of income for the PUC because it derived 89.8% of its funding from charges in the fiscal year 2017 (July 2016 to June 2017), of which KIUC fees comprised 3.9%.[81] This can impact the PUC's ability to carry out its functions in regulating other electric, gas, water, waste, and telecom utilities that remain under its jurisdiction. Lighter regulation of KIUC may not necessarily decrease the PUC's staffing needs and expenses because it is the smallest of Hawaii's electric utilities. Therefore, it could result in higher fees for other utilities.

[79] HRS §269-30. Finances; public utility fee. <http://www.capitol.hawaii.gov/hrscurrent/vol05_ch0261-0319/hrs0269/hrs_0269-0030.htm>

[80] Moss Adams. *Report of Independent Auditors and Consolidated Financial Statements – Kauai Island Utility Cooperative. December 31, 2017 and 2016*. April 2018.

[81] Hawaii Public Utilities Commission. *Annual Report for Fiscal Year 2017.* December 2017.

8 Steps required in forming the regulatory model

This section provides a list of steps necessary in establishing the proposed regulatory model. As discussed below, all the necessary steps in the establishment require actions led by the Hawaii PUC. If a new entity like HERA or ISO is established, certain types of surcharge and independent new hires will be needed. The role of utilities will change as the new regulatory model is developed. For instance, if an ISO is set up in Hawaii, it needs to acquire monitoring and dispatching functions and facilities from the utilities. If the distribution-focused regulatory model is selected, the utilities will shift their roles, for example, to act as distribution system platform providers instead of owners of DERs. Among the regulatory models studied, it seems like the distribution-focused regulatory model will be the most challenging to implement because of the presumed generation regulatory evolution, required responsibility transformation of utilities, and increased workload for the PUC.

8.1 Status quo with increased oversight[82]

As discussed earlier, there is already a law for the formation of the HERA. Setting up the HERA will be the next step. These steps include:

- ✓ The Hawaii PUC establishes qualification requirements for HERA by rule or order
- ✓ PUC details the scope of HERA activities
- ✓ The entity that will implement the HERA should be determined by the Hawaii PUC via competitive bid, scored request for proposal, or sole source procurement in certain situations (based on HRS 103D)
- ✓ The PUC orders that Hawaii electricity reliability surcharge will be collected to support the operations of HERA
- ✓ The HERA will hire staff members with appropriate skills and level of independence to develop and review reliability standards and interconnection requirements
- ✓ Once established, the HERA will review matters concerning reliability and interconnection and report to the Hawaii PUC on its operational and financial position annually

Moreover, as discussed earlier, there are some similarities between HERA and NERC. The textbox below provides a short discussion on the establishment of NERC. However, it should be noted that NERC's responsibility spans the continental US, Canada, and the northern

[82] Mayor's Office of Economic Development, Energy Commissioner, DKK, and SES. *Comparing the Structure and Function of a HERA to an ISO: Report and Task Analysis for use by the County of Maui*. August 25, 2017. Page 63.

portion of Baja California, Mexico[83] while HERA would be a much smaller organization covering the State of Hawaii only.

North American Electric Reliability Corporation ("NERC")

In November 1965, 30 million customers lost power in the US and Canada—this was the largest blackout to date in history. The US Electric Power Reliability Act proposed to create a council on power coordination in 1967. This stimulated the development of an industry electric reliability council. In response to the 1965 blackout and the recommendations of the Federal Power Commission (predecessor of the FERC), NERC was established by the electricity industry in June 1968.

In 1992, in one of six Agreements in Principle adopted by the Board, NERC Board of Trustees stated for the first time that conformity to NERC and regional reliability policies, criteria and guides should be ***mandatory*** to ensure reliability. The year after (1993), NERC published "NERC 2000", which built on the Agreement in Principle. It is a four-part action plan that recommends mandatory compliance with NERC policies, criteria, and guides and a process for addressing violations.

In response to FERC's Notice of Proposed Rulemaking on Open Access ("NOPR"), NERC filed six-point action plan in 1995 to address the planning and operating reliability aspects of the NOPR.

In 1997, the Electric System Reliability Task Force (established by the Department of Energy) and an independent Electric Reliability Panel ("Blue Ribbon" Panel, formed by NERC) determined grid reliability rules must be mandatory and enforceable in an increasingly competitive marketplace.

Proposed reliability legislation that would create an ***electric reliability organization*** was first introduced in US Congress by Senator Slade Gorton of Washington in 2000. In August 2005, Energy Policy Act of 2005 authorized the creation of an audited self-regulatory electric reliability organization and stated that compliance with Reliability Standards would be mandatory and enforceable.

In 2006, FERC certified NERC as the electric reliability organization for the US. The next year (2007), FERC approved 83 NERC Reliability Standards, the first set of ***legally enforceable standards*** for the US Bulk-Power System.

Currently, NERC's responsibilities include:

- development and enforcement of Reliability Standards,
- annual assessment of seasonal and long-term reliability,
- monitoring of the bulk power system through system awareness, and,
- education, training, and certification of industry personnel.

Source: NERC. *History of NERC.* August 2013.

8.2 Independent system operator

There are several steps in establishing an ISO, based on the experience of other ISOs/RTOs in North America. Below are some of the standard steps in its establishment:

- ✓ The PUC directs the establishment of an ISO, a non-profit third-party organization that can oversee equal access to the power grid
- ✓ The ISO forms a Board of Directors to oversee ISO operations, approve budget and staffing, establish market rules, and approve subsequent changes
- ✓ The ISO acquires or leases existing dispatch, monitoring, and control equipment, and hires staff[84] with appropriate skills in managing transmission/distribution system
- ✓ The ISO develops market rules, establishes stakeholder committees, and delineates PUC-ISO relationship
- ✓ The ISO, through stakeholder meetings, develops ISO tariff

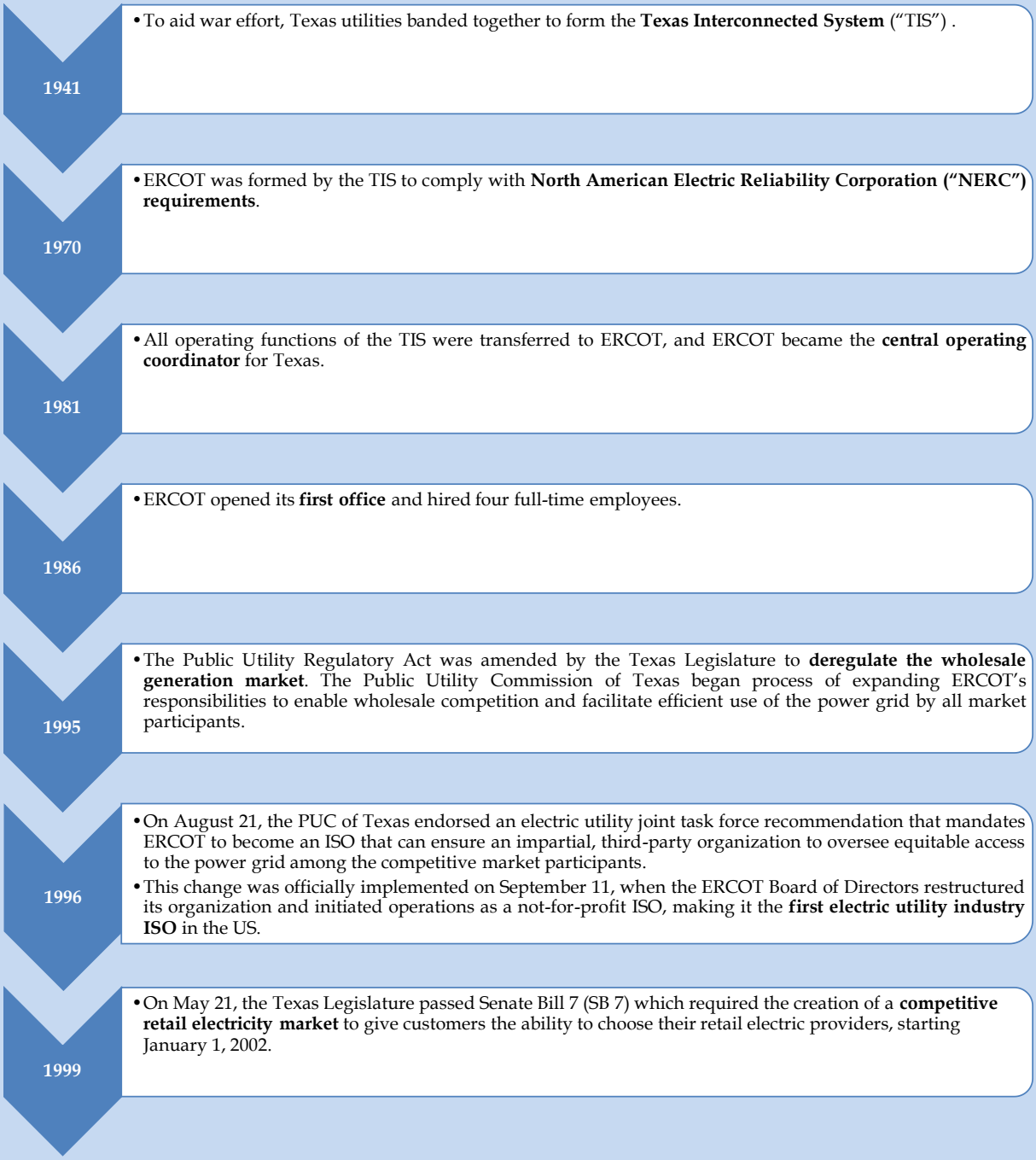
The ISO develops market protocols through stakeholder collaboration. Potential market protocols include but are not limited to: energy scheduling and dispatch; ancillary services; congestion management; outage coordination; settlement and billing; metering; data acquisition and aggregation; market information systems; transmission and distribution losses; registration and qualification; and market data collection, among others.

ERCOT[85] became the first ISO in the US in 1996. The textbox below provides a timeline of the formation of ERCOT. It is worth noting that, from 1999 to 2000, ERCOT developed market protocols (including rules and standards for energy scheduling and dispatch, ancillary services, congestion management, outage coordination, settlement and billing, transmission and distribution losses, market data collection, etc.) through stakeholder collaboration.

[84] Assets and staff could be transferred from utilities.

[85] Like Hawaii, ERCOT has no connections across state lines, so it is considered as "intrastate" and out of the jurisdiction of FERC.

Formation of the Electric Reliability Council of Texas ("ERCOT")



Source: ERCOT. *Company profile – History.*

8.3 Distribution-focused regulatory model

As described in Task 1 (Ownership models), moving to an integrated distribution-focused regulatory model necessitates piloting new and different ways in operating the electricity system and working with third-party DER providers. It also requires having a different business model for the utility.

Steps in implementing the distribution-focused regulatory model include the following:

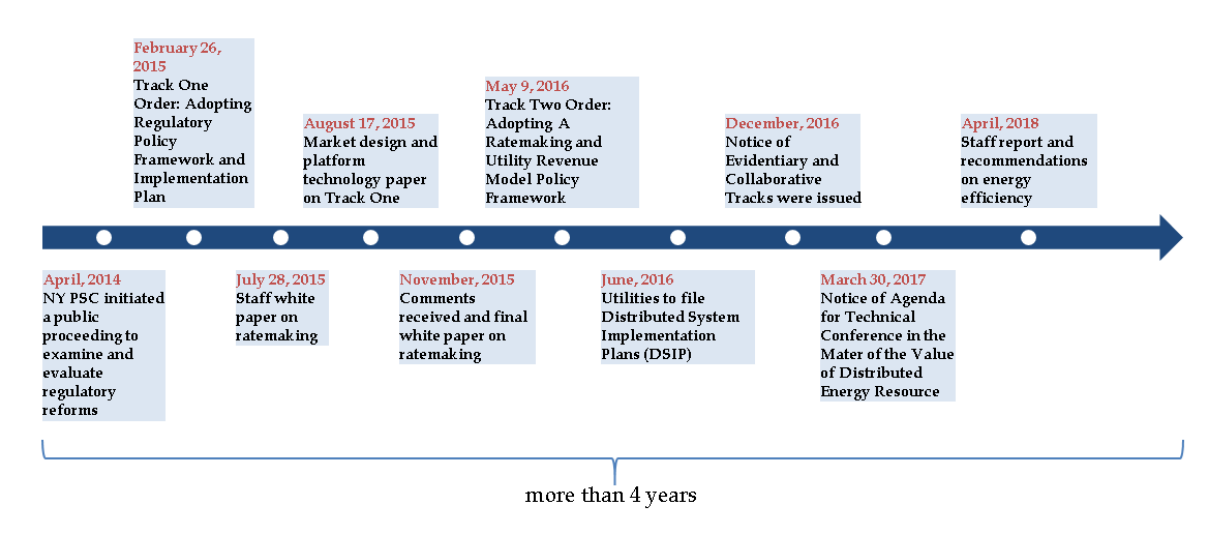
- ✓ The Hawaii PUC reviews the existing regulatory model and engages stakeholders in discussing and determining the definition of DSPP or DSO and how it will work[86]
- ✓ The Hawaii PUC orders that utilities to take on the new role of the DSPP
- ✓ The Hawaii PUC reviews the existing ratemaking approach and revises items, i.e., providing incentives to the utilities so they can support efficient DER integration, in line with their new role
- ✓ The DSO develops a distribution use of system charge that will facilitate wheeling within the distribution system
- ✓ The DSO installs independent board to oversee the DSO function
- ✓ The DSO identifies required additional technology in the implementation of DSPP and plans in financing and installation/establishment
- ✓ The DSO recruits employees who are not being seconded from the utility [applies to the IDSO only]
- ✓ The utilities file their DSIP including self-assessment of abilities in integrating distributed resources and their five-year roadmap to the PUC

In New York's REV proceeding, it took more than two years for the PSC to issue the Track Two Order, which serves as the foundational document regarding the utilities' revenue model. As of August 2018, it has been over four years since the PSC initiated the REV proceeding. Utilities are still in the process of adding details to their distributed system implementation plans, exploring opportunities for non-wires alternatives, and conducting pilots and demonstration projects with private sector industry participants. The textbox below shows the timeline of the New York REV experience.

[86] This process could be lengthy, given REV's experience (as shown in the textbox below).

Timeline of REV in New York

Through Governor Cuomo's *Reforming the Energy Vision* initiative, utilities in the New York State have been under regulatory reform and business model evolution. As of August 2018, this process has been ongoing for more than four years. The level of activity in the regulatory reform has been intense. Over 180 organizations, including utilities, power providers, non-profits, government agencies, etc., have filed more than a thousand documents regarding the initiative.



Source: NY. *DPS - Reforming the Energy Vision*. Makholm, Jeff. "The REVolution yields to a more familiar path: New York's Reforming the Energy Vision." *The Electricity Journal*. Volume 29. Issue 9, November 2016.

8.4 PBR

Moving from a traditional COS to PBR can be a huge task not only for the regulator but also for the utilities as well. It involves significant regulatory work and requires stakeholdering to determine the appropriate PBR mechanism that can be implemented and will allow more in-depth analysis of sectoral and technical issues (discussions of which are not always present or as thoroughly dissected during a COS deliberation). Nevertheless, as discussed earlier, Hawaii can learn from the experiences of jurisdictions that are currently under PBR.

The first 'formal' step in the PBR process is the regulator's expression of intent to implement a shift. In this step, the regulator is expected to explain the objectives clearly to all stakeholders as it embarks on the process. For example, in the case of Alberta, the Commission highlighted the goal of developing a regulatory framework that allows incentives for the regulated companies to improve their efficiency while ensuring that the benefits from the increase in efficiency will ultimately benefit customers.[87]

[87] Alberta Utilities Commission. Rate Regulation Initiative Decision 2012-237. September 12, 2012. P. 5. Website. <http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-237.pdf>

Experience and best practices dictate that the shift to a PBR mechanism requires the enumeration of principles that should guide the stakeholders (particularly the utilities) in the development and implementation process. The establishment of principles will assist the regulator in the evaluation of and deliberation on the PBR proposals. Such principles should also guide the utilities in developing the most responsive and relevant proposals. Below are the high-level steps in the transition to PBR:

- ✓ The regulator reviews the current ratemaking and regulatory model, announces intent to go into PBR, and releases indicative schedule for its implementation
- ✓ The regulator provides PBR educational seminars and stakeholder consultation workshops
- ✓ The regulator develops and releases proposed guiding principles for the PBR and stakeholders provide inputs to these principles
- ✓ Regulator finalizes and issues the PBR guiding principles and the regulatory implementation guidelines, which detail the type of PBR framework to be used, regulatory term (e.g., for three years), format of the PBR Plan, and documentation/evidence that is needed to be submitted to the PUC
- ✓ Utilities prepare their PBR plan and provide to the regulator
- ✓ Regulator reviews the PBR plan
- ✓ Interveners submit information requests and utilities submit information responses; oral hearings; utilities submit arguments
- ✓ Regulator issues its PBR decision

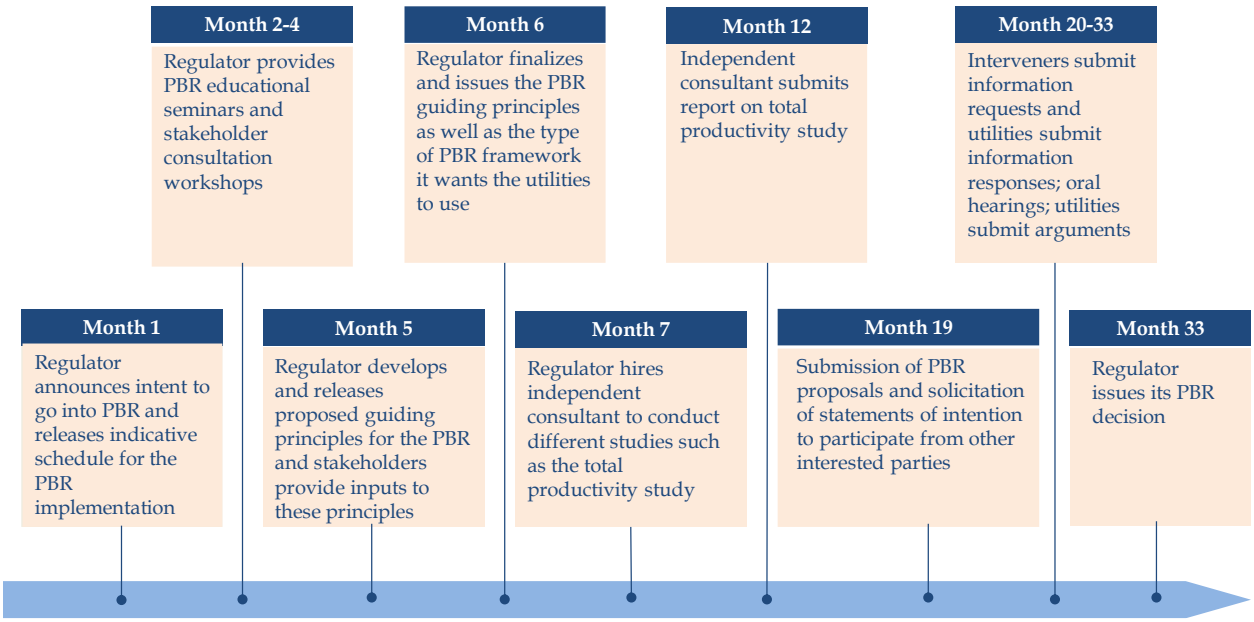
The shift to PBR often involves the steps and typical timelines that are shown in Figure 20.[88] This timeline is for a PBR launch; the timing could be less for the succeeding regulatory period. More detailed examples of two jurisdictions' move to PBR are provided in the textboxes below. As the experiences show, approximately one to three years are typically required.

Finally, data availability is a critical element in the development of a PBR regime and will improve the functionality of PBR regulation over time. The need for good data cannot be understated; incentive design could be significantly weakened by poor data. "Harder" forms of PBR require collating and employing multi-period information and data samples covering multiple firms. Over time, availability of reliable, comparable, and accurate data for the industry as a whole and the utilization of "best practice" forecasting tools can improve the functionality of the PBR

[88] This list is mostly adopted from the chronology of events involved in the shift to PBR of Alberta. Note, however, that the steps and timeline in this list are indicative only and depend on various factors such as government regulations, timely submission of reports and proposals, number of utilities and interveners, and strong consumer opposition or involvement, to name a few.

process, thereby, facilitating analysis and negotiations of parameters for PBR factors, as well as benchmarking actual productivity achieved against prior targets.

Figure 20. Move to PBR steps and timeline (Alberta experience)



Source: AUC Decision 2012-237.
Note: The timeline above is based on the experience of Alberta (except ENMAX) during the regulatory proceeding for the distribution utilities.

Ontario's move to PBR



In anticipation of the Energy Competition Act of 1998 (Bill 35) being passed, the Ontario Energy Board ("Board" or "OEB") stated its intent in October 1998 to consider PBR as a new approach to regulation. The first step undertaken by the Board toward the establishment of a framework for guidelines on PBR was the holding of a series of seminars in October and November of 1998 to familiarize stakeholders with the concept. Stakeholders were able to provide input for the most appropriate approach in PBR for electricity distribution. These inputs were compiled into a report (issued in December 1998), provides guidance to the Board going forward.

Four task forces—coordinated by Board staff—were then established to address the following topics: cap mechanism, yardstick mechanism, implementation, and distribution rates. These task forces consisted of 83 volunteer stakeholder members representing various electricity distributors, gas utilities, customer groups, and special interest groups. Task force meetings were conducted from mid-January 1999 through April 1999.

In the process, technical expertise on PBR and industry restructuring were provided to assist the task force. To address the diversity and large number of emerging issues on PBR and restructuring in general, working groups were formed within each of the task forces. The reports produced by these working groups were compiled by Board staff into task force reports and issued in mid-May 1999. Individual task force member position papers were included as appendices to the task force reports. To provide updates on the process to members who were not participating in the task forces, a web site was set up by the Board.

A draft of the *Board Staff Proposed Electric Distribution Rate Handbook* ("the draft Rate Handbook") was distributed on June 30, 1999. This draft document contains a proposal for a regulatory framework, which the Board used in developing and administering electricity distribution rates in the Province. Regional seminars were held across Ontario to provide stakeholders with an understanding and clarification of the proposal.

The draft Rate Handbook contained proposed rate policies, guidelines, and procedures, which were used by the Board in the establishment and adjustment of electricity distribution rates in Ontario for a first generation PBR plan. A series of presentations and a technical conference were held to discuss the draft Handbook.

On January 2000, the Board decided on a price cap framework. The proposed plan had a three-year term (2000-2002). The process—a bit over one year—is shorter than in Alberta.

Source: OEB website.

Illinois' move to PBR



The State of Illinois presents another example of a jurisdiction that has implemented a performance incentive mechanism ("PIM")-oriented PBR. The Energy Infrastructure Modernization Act ("EIMA") was signed into law on October 26, 2011. The EIMA provided a framework through which participating utilities could opt to recover electric delivery service costs through a performance-based formula rate provided that the participating utilities would also commit to undertake the infrastructure investment program as well as customer assistance programs as specified in Illinois Compiled Statutes ("ILCS") 5/16-108.5. Commonwealth Edison ("ComEd") and Ameren Illinois Company ("Ameren Illinois") opted to participate, thus, regulated by the Illinois Commerce Commission ("ICC").

The law not only authorized the smart grid investment but also set reliability and various performance metrics that must be achieved over the ten-year period (2012-2021). To assure that consumers would benefit from this change, the law set forth the following metrics:

- 20% improvement in the System Average Interruption Duration Index ("SAIDI");
- 15% improvement in the Customer Average Interruption Duration Index ("CAIDI");
- 20% improvement in the System Average Interruption Frequency Index ("SAIFI");
- 75% improvement in the total number of customers who exceed the service reliability targets;
- 90% reduction in issuance of estimated electric bills;
- 90% reduction in consumption on inactive meters;
- 50% reduction in unaccounted for energy (i.e. non-technical line loss); and
- $30,000,000 reduction in uncollectible expense.

These metrics were established as penalty-only performance incentives, where progress was required in equal segments over a ten-year period. Put differently, each year the participating utility does not meet the set goal, it faces a penalty of a return-on-equity ("ROE") reduction of 5 basis points in years 1 through 3, 6 basis points in years 4 through 6, and 7 basis points in years 7 through 10. To avoid a penalty, the participating utility must achieve full progress on reliability goals and 95% progress on other goals (220 ILCS 5/16-108.5).

Nonetheless, environmental and consumer groups were not satisfied with these performance metrics as they failed to address several other benefits of smart grid investments. Stakeholder discussions ultimately resulted in an agreement in 2013 between the groups and ComEd, approved by the ICC, whereby additional performance metrics to be tracked were added to the list, including (but not limited to) the following: reductions in greenhouse gas ("GHG") emissions; load served by distributed energy resources ("DERs"); time required to connect DERs to the grid; peak load reduction through demand response ("DR"); and customers enrolled in time-varying rates. While these additional performance metrics did not result in penalties or rewards, they did allow regulators and stakeholders to assess the investment's benefits. Overall, over sixty performance metrics were developed.

Source: Illinois Commerce Commission; 220 ILCS 5/16-108.5; NREL & RAP.

9 Appendix A: Scope of work to which this deliverable responds

Task 2.2.1 Comparative review of regulatory models, including a high-level process assessment.

CONTRACTOR shall provide a comparison of the regulatory models: 1) how they are similar to and/or different from each other; 2) the relative advantages and disadvantages of each, and 3) the steps required for their formation.[89] Evaluate each model's ability to: (a) achieve State energy goals; (b) maximize consumer cost savings; (c) enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs; (d) eliminate or reduce conflicts of interest in energy resource planning, delivery and regulation; and (e) align management, ownership and ratepayer interests.

DELIVERABLE FOR TASK 2.2.1. CONTRACTOR shall provide its conclusions and all work related to providing a comparative review of the regulatory models including a high-level process assessment. CONTRACTOR shall include an assessment of each model by various criteria, an assessment of the pros and cons of these models from Hawaii's perspective, and steps required to transition to each regulatory model. CONTRACTOR shall then evaluate each regulatory model's potential to 1) achieve state energy goals, 2) maximize customer cost savings, 3) enable a competitive distribution system, and 4) reduce conflicts of interest in energy resource planning, delivery, and regulation. CONTRACTOR shall assess each regulatory model from three perspectives: management, ownership, and ratepayer interests. CONTRACTOR shall provide a document in MS Word which summarizes the above and a PowerPoint presentation. CONTRACTOR shall submit deliverable for TASK 2.2.1 to the STATE for approval.

[89] We want to note that we have provided a discussion on this in Task 2.1.1.k 2.

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Assessment of current markets under each regulatory model

working paper prepared by London Economics International LLC for the State of Hawaii with support from Meister Consultants Group

August 20, 2018



London Economics International LLC ("LEI"), together with Meister Consultants Group, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership and regulatory models to support the State in achieving its energy goals. This document is one of several working papers associated with that engagement. It provides a case study for each of the regulatory models being assessed, including independent system operator ("ISO") model, distribution focused regulatory model, performance-based regulation ("PBR") model, and lighter regulation for KIUC. Also, for the ISO model and the PBR model, the Project Team reviewed three markets that have changed to these models. For the lighter regulation option for KIUC, the Project Team examined three states that have different arrangements for the regulation of generation and transmission cooperatives ("co-ops"). These case studies offer some insights of best practices as well as some lessons learned for Hawaii, which it can consider as it contemplates selecting and transitioning to a new regulatory model.

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List of acronyms

AER	Australian Energy Regulator
AESO	Alberta Electric System Operator
BCF	Business Carbon Footprint
BETTA	British Electricity Trading Transmission Arrangements
BMCS	Broad Measure of Customer Service
CAISO	California Independent System Operator
Capex	Capital expenditure
CES	Clean Energy Standard
CHP	Combined heat and power
DBEDT	Hawaii Department of Business Economic Development and Tourism
DECC	Department of Energy and Climate Change (UK)
DER	Distributed energy resources
DNOs	Distribution network operators
DSIP	Distributed System Implementation Plan
DSPP	Distributed System Platform Providers
EDF	Électricité de France
EDR	Environmental Discretionary Reward
EIM	Energy Imbalance Market
ENS	Energy Not Supplied
ERC	Energy Regulatory Commission (Philippines)
ERCOT	Electric Reliability Council of Texas
ESCOs	Energy service companies
EUB	Energy and Utilities Board (Alberta)
FERC	Federal Energy Regulatory Commission
GEMA	Gas and Electricity Markets Authority (UK)
GMC	Grid Management Charge
HSE	Health and Safety Executive
IBR	Incentive-based regulation
ICE	Incentive on Connections Engagement
IDER	Integrated distributed energy resources
IESO	Independent Electricity System Operator (Ontario)
IIS	Interruptions Incentive Scheme
IOUs	Investor-owned utilities
IQI	Information Quality Incentive
IRM	Innovation Roll Out Mechanism
ISO	Independent system operator
ISO-NE	Independent System Operator New England

LDR	Losses Discretionary Reward
LEI	London Economics International LLC
MISO	Midcontinent Independent System Operator
NERC	North American Reliability Council
NETA	New Electricity Trading Arrangements
NGET	National Grid Electricity Transmission
NIA	Network Innovation Allowance
NIC	Network Innovation Competition
NY PSC	New York Public Service Commission
NYISO	New York Independent System Operator
NYPA	New York Power Authority
Ofgem	Office of Gas and Electricity Markets (UK)
Opex	Operating expenditure
PBR	Performance-based regulation
PGC	Power generation companies
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PUCT	Public Utility Commission of Texas
REPs	Retail electric providers
REV	Reforming the Energy Vision
RIIO	Revenue = Incentives + Innovation + Outputs
RO	Renewable obligation
RORE	Return on regulatory equity
RPS	Renewable portfolio standards
SECV	Stakeholder Engagement and Consumer Vulnerability
SHETL	Scottish Hydro Electric Transmission Limited
SPP	Southwest Power Pool
SPTL	Scottish Power Transmission Limited
SSE	Scottish and Southern Energy
ST	Suruhanjaya Tenaga
TDSPs	Transmission and distribution service providers
TIS	Texas Interconnected System
TO	Transmission owners
TTC	Time to Connect Incentive
UK	United Kingdom
VoLL	Value of Lost Load

1 Executive summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which responds to Task 2.2.2 in the project scope of work, provides an assessment of current markets under each regulatory model, including a case study, analysis, and conclusions. We have also provided examples of jurisdictions that have changed regulatory model in the last 20 years and lessons learned from these markets.

The Project Team has selected the following markets as case study for jurisdictions that are currently implementing the regulatory model: Texas (independent system operator model or "ISO"), New York (distribution-focused regulatory model), and the UK (performance-based regulation model or "PBR") and Alaska (lighter regulation from PUC). Jurisdictions were selected due to their representativeness as well as their similarities with Hawaii. The case studies include background information on the jurisdiction's electricity sector including an overview of the electricity market, the current regulatory framework, history of transition along with recent developments, and lessons learned from these markets. Detailed review and analysis are provided to help the reader better understand each regulatory model and what aspects should be taken into consideration to move to the regulatory model.

The review of markets that have changed or moved to the regulatory models that are being assessed in the last 20 years covers nine jurisdictions. Since there are no other jurisdictions that have entities like HERA or have a full-blown distribution-focused regulatory model, the Project Team focused on the other three alternative models instead. The Project Team reviewed California, Ontario, and Alberta as case studies for the ISO model. Australia, the Philippines, and Malaysia were assessed as case studies for the PBR model. In addition to Alaska, Colorado, and Utah's cases were studied for the lighter regulation model for Kauai Island Utility Cooperative ("KIUC"). These case studies were provided to show that even under the same regulatory model, there are different regimes and arrangements that Hawaii could learn from.

Based on the experience of these jurisdictions, several key findings emerged, which would be useful for Hawaii to keep in mind as it evaluates its options:

- transition to the regulatory model at the right time (avoiding high demand periods) and gradually,
- set appropriate rates to protect both the utilities and the customers,
- provide mechanisms to ensure that capital investments are recouped in a timely manner,
- provide mechanisms to manage risks beyond utilities' control, and,
- put in place mandatory performance standards.

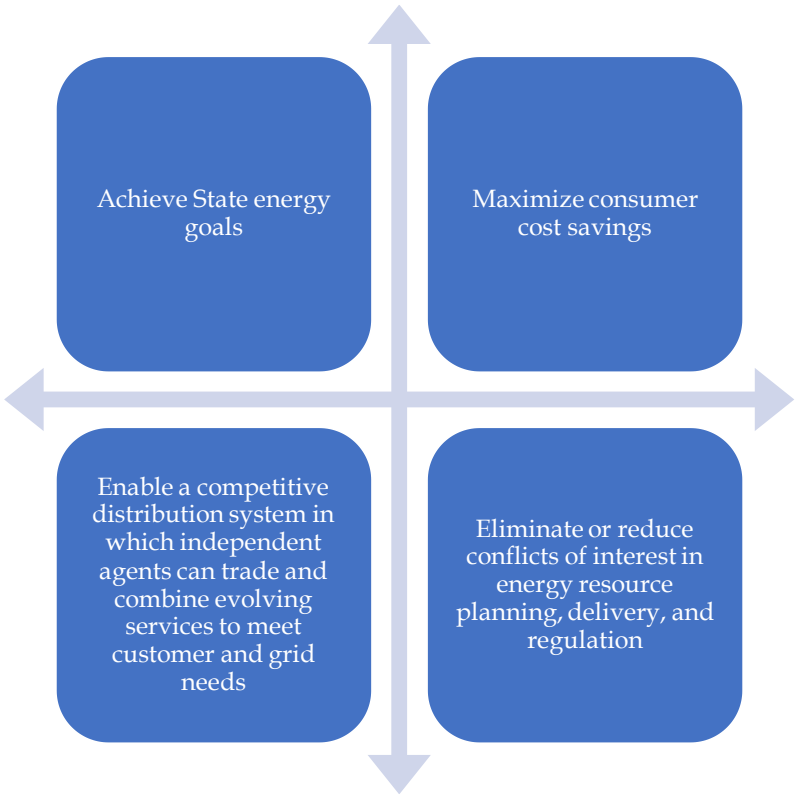
2 Introduction and scope

2.1 Project description

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission on a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[1] was contracted to perform this study.[2]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[3] listed in Figure 1.

Figure 1. State's key criteria in evaluating the models



Source: Scope of Services under Contract No. 65595

[1] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[2] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[3] House Bill No. 1700 Relating to the State Budget.

The study will help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[4]

2.2 Role of this deliverable relative to others in the project

This deliverable is responsive to Task 2.2.2 in the project scope of work. It assesses current markets under each regulatory model. The Project Team reviewed examples of current markets under each regulatory model and examples of markets that have changed regulatory model in the last 20 years. Case studies are included to highlight the essential features of different regulatory models and critical issues and lessons from other jurisdictions. Analysis and conclusions of this research are summarized in this memo.

[4] Hawaii Contract No. 65595. Scope of Services.

3 Overview of the case studies

This deliverable presents case studies of current markets under each regulatory model and six jurisdictions that have changed regulatory models. Regulatory models that were examined in this deliverable include independent system operator ("ISO"), distribution-focused regulatory model, performance-based regulation ("PBR") model, and lighter regulation for KIUC.[5]

The case studies provide a detailed assessment of the regulatory models. In particular, the case studies give an overview of the electricity market in that jurisdiction, followed by its current regulatory framework, history of transition to the regulatory model, and recent developments. Finally, each case study presents key takeaways for Hawaii. In addition, the Project Team provides examples of markets that have changed their regulatory model in the last 20 years, including identifying market features such as some utilities, customers served, capacity, annual sales, and retail rates, as data are available. Lessons learned from these markets were provided also discussed in each case study.

3.1 Case selection

The selection of the markets covered in this report is based on a variety of factors as shown in Figure 2. These factors include, but are not limited to, extensive experience with the specified regulatory model, a single-state regulatory structure, similar market size as that of Hawaii, and similar geography as that of Hawaii (i.e., archipelago).

For the markets that are currently under each regulatory model, we chose Texas as a case study for the ISO model because, like Hawaii, it has a single state ISO outside of Federal Energy Regulatory Commission's ("FERC") jurisdiction. New York was chosen as an example for the distribution-focused regulatory model because it is the only pioneer transitioning to this new model right now. The United Kingdom ("UK") has extensive experience in PBR having implemented it for more than two decades. Moreover, UK's "Revenue = Incentives + Innovation + Outputs" ("RIIO") model was also mentioned in the Hawaii PUC's order on PBR as "*one of the best-known examples of PBR in practice.*" [6]

Finally, for markets that have changed regulatory models in the last 20 years, we reviewed the year of establishment of all the ISOs and selected single-state ISOs (other than Texas) and which have other similarities to Hawaii (e.g., California, Ontario, and Alberta). While multiple jurisdictions have implemented PBR, we focused on markets that had similarities to Hawaii – in terms of relative size or island composition (e.g., Australia, the Philippines, and Malaysia).

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[5] "Status quo with increased oversight" model was not included in this discussion, as currently there is no single-state Electricity Reliability Administrator that is similar to the concept of Hawaii Electricity Reliability Administrator ("HERA").

[6] Hawaii PUC. *Instituting a Proceeding to Investigate Performance-Based Regulation* (Order No. 35411). Docket No. 2018-0088. April 18, 2018.

Figure 2. Rationale for selection of the case studies

Jurisdiction	Regulatory model	Rationale for choosing this jurisdiction
Current markets under each regulatory model		
Texas	ISO	Single-state ISO that is in NERC's jurisdiction but out of FERC's jurisdiction
New York	Distributed-focused	A pioneer state that is transitioning to the distributed-focused regulatory model*
UK	PBR	More than two decades of experience in PBR with new PIMs features in RIIO
Alaska	Lighter regulation for co-op	Most of the retail customers are served by co-ops; dominated by vertically-integrated utilities
Markets that have changed regulatory model in the past 20 years		
California	ISO	Single-state ISO that was set up in the past 20 years; aggressive renewable policies and initiatives
Ontario	ISO	Single-province ISO that was set up in the past 20 years; aggressive renewable policies and initiatives
Alberta	ISO	Single-province ISO that was set up in the past 20 years; relatively small market compared to other ISOs
Australia	PBR	An isolated market; under PBR since 1997
The Philippines	PBR	Consisting of islands; only one transmission utility; under PBR since 2003; several distribution utilities that are owned by coops
Malaysia	PBR	Consisting of islands; vertically-integrated utility under PBR; PBR was developed to promote efficiency and service standards, etc.
Colorado/ Utah	Lighter regulation for co-op	Has co-ops with generation but treat them differently from how Alaska treats co-ops with generation

* Currently, there is no jurisdiction that has a full-blown distribution-focused regulatory model.

3.2 Overview of the jurisdictions covered in the case studies.

Regulatory models' transitions are usually jurisdiction-based (at the country or state/provincial level), unlike transitions of ownership models which involves companies only. Since there are many factors, like economic development and population growth, that impact the number of utilities, number of customers, total capacity, annual sales, and retail rates, etc., it makes less sense to compare these numbers before and after the regulatory models' transition, as these factors will not change due to a change in the regulatory model. Therefore, the Project Team focused on the analysis of the development itself but provided the most recent data available (2016) as general background information for the jurisdictions that were evaluated. Figure 3 shows the key energy statistics about select jurisdictions.

Figure 3. Summary of selected jurisdictions

Current markets under each regulatory model

Market	Regulatory model	Number of Utilities	Number of customers	Capacity (MW)	Annual sales (MWh)	Average retail rates (cents/kWh)
Hawaii	Status Quo	4	506,216	2,893	9,445,389	23.87
Texas	ISO	34	11,975,355	103,607	398,661,809	8.43
New York	Distribution-focused	6	693,283	44,513	147,803,038	14.47
UK	PBR	17	28,000,000	78,279	288,129,030	23.21
Alaska	Lighter regulation	8	337,407	2,742	6,123,202	17.93

Markets that have changed regulatory model in the past 20 years

Market	Regulatory model	Number of Utilities	Number of customers	Capacity (MW)	Annual sales (MWh)	Average retail rates (cents/kWh)
California	ISO	14	16,029,429	70,960	284,119,456	14.68
Alberta	ISO/ PBR	11	1,750,000	16,423	79,560,000	8.11
Ontario	ISO/ PBR	71	5,106,528	36,070	130,194,307	12.23
Australia	PBR	21	6,755,510	42,862	196,500,000	19.22
The Philippines	PBR	130	18,519,029	21,423	74,153,000	16.03
Malaysia	PBR	3	9,659,221	26,563	124,709,000	8.66
Colorado	Lighter regulation	6	2,643,315	16,078	54,802,037	9.83
Utah	Lighter regulation	1	1,175,934	8,976	30,179,534	8.72

Notes: 2016 numbers. Average retail rates are in US dollars (1 Euro = 1.19 USD, 1 CAD = 0.78 USD, 1 AUD = 0.75 USD, 1 MYR = 0.26 USD). Different from the ownership model transition, the utility credit rating of each utility in the market is less relevant to the purpose of this regulatory models' review, and thus, was not included in this memo. There are more than 100 utilities in the Philippines because it comprises of more than 7,000 islands. The number of customers refers to the total number of customers (approximate), and the number of utilities refers to the total number of transmission and distribution ("T&D") utilities.

Source: EIA. S&P Global. Ofgem. Eurostat. Australian Energy Market Commission. Meralco. TNB. OEB. IESO. Utilities Consumer Advocate, etc.

3.3 Lessons learned from the case studies

Various lessons can be drawn from the case studies under each regulatory model. However, no matter which regulatory model Hawaii's electricity sector will transition to, there are some general lessons learned from other jurisdictions that will be relevant:

- **Transitioning the regulatory model at the right time:** transitioning the regulatory model tends to affect new build or infrastructure investment by utilities due to uncertainty about the final shape of the model. If this postponement happens during a high demand period, it will cause blackouts or even unexpected crisis.

- **Transitioning the regulatory model gradually**: most if not all markets require adequate preparatory and early-stage implementation periods. Mainly for the generation sector, the gradual introduction of competition contributed to a successful transition.[7]

- **Setting appropriate rates to protect both the utilities and the customers**: jurisdictions that have successfully implemented PBR have set rates that enable the utilities to meet their obligations to customers as well as earn sufficient rates of return to support future investments.

- **Providing mechanisms to manage risks beyond utilities' control**: for the ISO model, regulators need to closely monitor the risks and design backup policies to maintain a stable market. For the PBR model, mechanisms such as exogenous factors, flow-through, and reopeners are necessary to manage the utilities' risks that are beyond their control. For the lighter regulation model, the PUC should provide backup designs to co-op members if the board of directors does not act to serve members' interests.

[7] For instance, it took ISO-NE four years to adopt the "standard market design" including features like day-ahead market in 2003, after it implemented the wholesale energy market in 1999.

4 Markets currently under each regulatory model

This section provides a more detailed assessment of the regulatory models and a case study of one jurisdiction under each of the regulatory models. As shown in Figure 4, Texas, New York, and the UK were selected as sample markets that are under ISO model, distribution-focused regulatory model, and PBR model, respectively.

Figure 4. Summary of selected current markets under each regulatory model

Market	Regulatory model	Number of Utilities	Number of customers	Capacity (MW)	Annual sales (MWh)	Average retail rates (cents/kWh)
Hawaii	Status Quo	4	506,216	2,893	9,445,389	23.87
Texas	ISO	34	11,975,355	103,607	398,661,809	8.43
New York	Distribution-focused	6	693,283	44,513	147,803,038	14.47
UK	PBR	17	28,000,000	78,279	288,129,030	23.21
Alaska	Lighter regulation	8	337,407	2,742	6,123,202	17.93

Note: 2016 numbers. UK's retail electricity rates were converted to USD using the 2016 exchange rate. The number of customers refers to the total number of customers (approximate), and the number of utilities refers to the total number of T&D utilities.
Source: EIA. Ofgem. Eurostat.

4.1 Independent system operator: Texas

4.1.1 Overview of the Texas market

The Electric Reliability Council of Texas ("ERCOT") is the ISO that operates the transmission grid and administers the wholesale electricity market in most of Texas. The ERCOT controlled area covers 75% of the state's total area[8] and provides energy to 85% of the state's total load.[9] ERCOT operates a nodal real-time balancing market, as well as day-ahead energy and ancillary services co-optimized market, supplemented with hourly reliability unit commitment. The ERCOT market is dominated by natural gas capacity and generation, contributing shares of 62% and 49% respectively, as shown in Figure 5.

[8] Other parts of Texas area are served by utilities belonging to the Southwest Power Pool, the Southeastern Electric Reliability Council, and the Western Electricity Coordinating Council.

[9] LEI. *LEI Semi-annual Regional Market Update and 10-year Energy Forecast: ERCOT.* 3rd Quarter 2017.

Figure 5. Texas electricity market snapshot

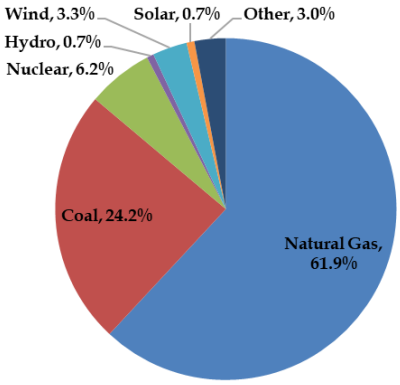
Texas



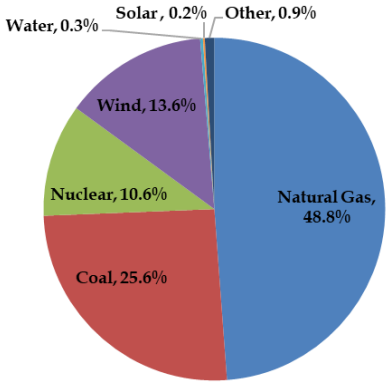
Key facts

Population (2016)	27.9 million
GDP growth (2016)	2.8%
Installed capacity (2016)	103.6 GW
Peak demand (2016)	71.1 GW
Load growth (2012-2016)	1.7%
Generation (2016)	377 TWh
No. of utilities	34

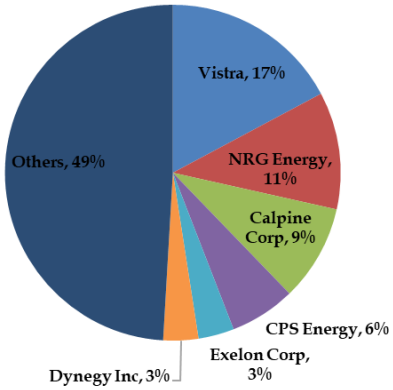
Installed capacity by fuel type (2016)



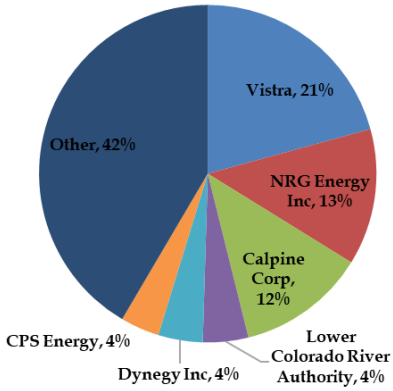
Generation by fuel type (2016)



Top players by installed capacity (2016)



Top players by generation (2016)



Note: The number of utilities refers to the total number of T&D utilities.
Sources: US Census Bureau. *State Population Totals and Components of Change: 2010-2017.* January 18, 2018; "Regional Data." *US Department of Commerce.* <https://www.bea.gov/iTable/index_regional.cfm>; S&P Global Market Intelligence. *PUC of Texas. Directory of Transmission & Distribution Utilities.* <https://www.puc.texas.gov/industry/electric/directories/tdu/search_tdu.aspx>

There are 381 power generation companies ("PGCs") currently registered with and regulated by the Public Utility Commission of Texas ("PUCT").[10] As defined by the PUCT, a PGC is *"a person that generates electricity intended to be sold at wholesale and does not own a transmission or distribution facility in [the] state."*[11] Vistra, NRG Energy, and Calpine operate 37% of generating capacity and provide 46% of the energy consumed in ERCOT.[12]

There are 34 transmission and distribution service providers ("TDSPs") in Texas, responsible for owning, maintaining, and operating transmission assets in the State, including IOUs, municipal-owned electric utilities, and co-ops. TDSPs are regulated by the PUCT and are required to provide non-discriminatory access to the grid.[13]

The retail electric market in Texas opened in 2002, brought about by the passage of Senate Bill 7 by the Texas Legislature, which began the project of restructuring the Texas electricity market.[14] There are currently 116 retail electric providers ("REPs") registered with the PUCT.[15] As defined by the PUCT, a REP *"sells electric energy to retail customers in the areas of Texas where the sale of electricity is open to retail competition. A REP buys wholesale electricity, delivery service, and related services, prices electricity for customers, and seeks customers to buy electricity at retail."*[16]

Hawaii and Texas have several similarities that make Texas a good example for the ISO model. For one, ERCOT was established in one single state - Texas, and it is out of FERC's jurisdiction[17] (like Hawaii). Also, similar to Hawaii, Texas has a stand-alone electricity grid which is mostly isolated from the interconnected power systems serving the eastern and western United States.

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[10] Public Utility Commission of Texas. *Power Generation Companies – Search.* Website. < https://www.puc.texas.gov/industry/electric/directories/pgc/search_pgc.aspx>. Access Date: April 24, 2018.

[11] "Certification and Licensing." *PUCT.* <https://www.puc.texas.gov/industry/electric/business/pgc/pgc.aspx> Access Date: April 23, 2018.

[12] Third party commercial database.

[13] "Transmission/Distribution Service Providers." *ERCOT.* <http://www.ercot.com/services/rq/tdsp> Access Date: April 23, 2018.

[14] PUCT. *2017 Scope of Competition in Electric Markets in Texas.* January 2017.

[15] PUCT. *Retail Electric Providers.* < https://www.puc.texas.gov/industry/electric/directories/rep/alpha_rep.aspx>. Access Date: May 10, 2018.

[16] "Certification and Licensing." *PUCT.* <https://www.puc.texas.gov/industry/electric/business/rep/rep.aspx> Access Date: April 23, 2018.

[17] According to FERC, "the transmission grid that the ERCOT administers is located solely within the state of Texas and is not synchronously interconnected to the rest of US. The transmission of electric energy occurring wholly within ERCOT is not subject to the Commission's jurisdiction under sections 203, 205, or 206 of the Federal Power Act." Source: FERC. RTO/ISO – ERCOT. Website. <https://www.ferc.gov/industries/electric/indus-act/rto/ercot.asp>

Moreover, both Hawaii and Texas have observed significant renewable development in the past few years, although the renewable energy development in Texas is mostly driven by favorable wind conditions and easy siting rather than state policy. However, unlike Hawaii, the Texas Reliability Entity ("Texas RE")[18], a Regional Entity, is part of North American Electric Reliability Corporation ("NERC"). There is no Regional Entity in Hawaii. Moreover, the current RPS is not the primary driver for renewables development in Texas, as the 10,000 MW renewable target was met in 2010. Moreover, Texas is much larger than Hawaii in terms of annual sales and peak demand. Hawaii's annual sales in 2016 represented only 2% of Texas' annual sales.[19]

4.1.2 Overview of the regulatory framework in Texas

As mentioned above, ERCOT serves as an ISO, managing the flow of electrical power to 24 million customers[20] in the state of Texas. Governed by a sixteen-member board of directors, subject to oversight from the PUCT and the Texas legislator, ERCOT has members including consumers, cooperatives, generators, power marketers, retail electric providers, IOUs (transmission and distribution providers) and municipal-owned electric utilities.[21] ERCOT's main responsibilities include: (i) ensuring system reliability through planning and operations; (ii) settling the wholesale market for electricity production and delivery; (iii) overseeing the retail switching process for customer choice; and (iv) ensuring open access to transmission.[22]

Unlike other ISOs, which are subject to FERC's oversight, ERCOT operates under the regulation of the PUCT as ERCOT has few connections with the two major US interstate grid systems, the Eastern and the Western Interconnections. The PUCT is responsible for the regulation and oversight of the competitive wholesale and retail electric markets, regulating the State's generation, transmission, and distribution owners.[23] This structure is similar to Hawaii's current regulatory framework, i.e., out of FERC's jurisdiction but under the PUC's regulation, which implies that an ISO model could be feasible in its current regulatory environment.

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[18] The Texas RE is a not-for-profit corporation that serves as the Regional Entity for the parts of Texas that is overseen by ERCOT. The Texas RE holds a Delegation Agreement with NERC, approved by FERC, authorizing it to "*develop, monitor, assess, and enforce compliance with NERC Reliability Standards; develop regional standards; [and] assess and periodically report on the reliability and adequacy of the bulk power system.*" The Texas RE is one of eight Regional Entities established to carry out "*compliance monitoring and enforcement activities…on behalf of NERC*", which NERC oversees to ensure "*consistency and fairness*." (Source: "About Us." *Texas RE.* Web. August 10, 2018. <https://www.texasre.org/Pages/About-Us.aspx>; "Regional Entity Compliance Programs." *NERC.* Web. August 10, 2018. <https://www.nerc.com/pa/comp/Pages/Regional-Programs.aspx>)

[19] EIA. *Electricity statistics*. Website. <https://www.eia.gov/electricity/state/>. Access Date: April 24, 2018.

[20] "Electric Power Markets: Texas (ERCOT)." *FERC.* <https://www.ferc.gov/market-oversight/mkt-electric/texas.asp> Access Date: April 23, 2018.

[21] Ibid.

[22] Association of Electric Companies of Texas Inc. *The Wholesale Electric Market in ERCOT*. 2017.

[23] PUCT. "About the PUCT.". <https://www.puc.texas.gov/agency/about/mission.aspx> Access Date: April 23, 2018.

4.1.3 History of transition and recent development

The establishment of ERCOT can be traced back to 1970 when the Texas Interconnected System[24] ("TIS") formed ERCOT to comply with North American Reliability Council's ("NERC") requirements. At that time, ERCOT was staffed by two retired employees from the utilities.[25] In 1981, ERCOT assumed the Central Operating Coordinator role as TIS transferred all operating functions to ERCOT. In 1995, the Texas legislature voted to deregulate the wholesale generation market by amending the Public Utility Regulatory Act. ERCOT's responsibilities were expanded by the PUCT to enable wholesale competition.[26] In 1996, the ERCOT Board of Directors restructured its organization and initiated operations as a not-for-profit ISO on September 11, 1996. This change made ERCOT the first electric utility industry ISO in the US.

From 1999 to 2000, ERCOT protocols (i.e., how ERCOT's organization supports competitive markets while maintaining the reliability of electric services) were developed through stakeholder collaboration. Rules and standards for implementing market functions include but are not limited to "energy scheduling and dispatch, ancillary services, congestion management, outage coordination, settlement and billing, metering, data acquisition and aggregation, market information systems, transmission and distribution losses, renewable energy credit trading, registration and qualification, market data collection, load profiling and alternative dispute resolution."[27] On July 31, 2001, ten (10) control centers merged into one control center. Under the new electric industry restructuring guidelines, power scheduling was centralized, and ancillary services were procured to ensure reliability. Commercial functions were centralized to "facilitate efficient market operations and enable switching by customers between competitive electricity providers."[28] The competitive retail electric market was launched to allow customers to choose power suppliers on January 1, 2002. This was specifically applied to investor-owned utilities ("IOUs") but allowed municipal utilities and cooperatives to opt-in to participate in the competition.[29] In 2003, the PUCT ordered ERCOT to develop a nodal wholesale market design to improve market and operating efficiencies and the nodal market with features like "locational marginal pricing for generation at more than 8,000 nodes, a day-ahead energy, and ancillary

[24] As part of the war effort in 1941, the TIS was created by a number of Texas utilities in order to pool energy and share transmission lines. Texas utilities maintained the TIS after World War II and eventually the organization established two monitoring centers, both located within the control centers in north and south Texas. Source: ERCOT. Company Profile - History.

[25] ERCOT. *Company Profile - History*. Web. <http://www.ercot.com/about/profile/history>. Access Date: May 4, 2018.

[26] Ibid.

[27] Ibid.

[28] Ibid.

[29] Ibid.

services co-optimized market, day-ahead, and hourly reliability-unit commitment, and congestion revenue rights" was launched in December 2010.[30]

Regarding renewables development, by 2006, Texas moved ahead of California as the top wind-producing state.[31] In 2016, grid-scale solar capacity totaled 554 MW, and ERCOT established a new solar forecast to support the reliable integration of this rapidly developing generation source. Moreover, on March 23, 2016, wind served 48.2% of load (a new record).

4.1.4 Implications for Hawaii

There are several lessons from Texas' electricity market ISO experience.

- **The Hawaii PUC could take the lead to set up an ISO, as the state is not under FERC's jurisdiction.** Like the PUCT, the Hawaii PUC could lead the process of establishing an independent, not-for-profit entity. Also, like the PUCT, the Hawaii PUC can have oversight and enforcement authority over the ISO protocols, operating guides, and other binding documents.[32] Furthermore, the Hawaii PUC can approve the resource plans that the ISO puts together.

- **If the Hawaii PUC decided to set up an ISO, the control and dispatch center needs to be acquired.** As mentioned above, an ISO needs to own or lease the control center, dispatch, and monitoring facilities to manage the transmission and distribution system. Currently, utilities own and operate these facilities. If created in Hawaii, the new ISO would need to acquire the equipment from utilities and probably hire former utility employees who are skilled and experienced to perform the technical job. Also, the PUC should set up specific policies to address possible conflict of interests.

- **A state-wide ISO requires more supply-demand coordination among counties.** As illustrated in Task 1.1.3 (Existing generation, transmission, and distribution infrastructure in Hawaii), each county has its generation resource characteristics. A state-wide ISO could continue to operate the dispatching and monitoring of each county's market separately or merge the control centers into one. If the ISO plans to have one control center, inter-island transmission connection would be required. Based on ERCOT's experience, expanding interconnection within the State could benefit the system as it brings additional supply to meet demand in populated areas. For instance, ERCOT constructed more than 3,600 miles of transmission lines to move its wind generation from the West Texas and Panhandle regions to more populated regions of the ERCOT grid.[33] With the transmission

[30] Ibid.

[31] Ibid.

[32] ERCOT. *Compliance in ERCOT*. Website. <http://www.ercot.com/mktrules/compliance>. Access Date: June 28, 2018.

[33] ERCOT. Company Profile - History. Web. <http://www.ercot.com/about/profile/history>. Access Date: May 4, 2018.

construction, wind served more than 48% of the load, which was a record in 2016. Nevertheless, an interconnection of the different islands is unlikely to happen due to cost and environmental concerns. As mentioned in Task 1.1.5, the HECO Companies evaluated the interconnection between Oahu and Maui island, but found that the gross benefits were "*substantially less than the estimated cost of a cable*."[34]

- **It takes time to go through a stakeholder process to develop ISO's rules and standards.** It took ERCOT almost two years to go through the stakeholder collaboration to set up the rules and standards for its markets.

4.2 Distribution focused regulatory model: New York

4.2.1 Overview of the New York market

The New York electricity market is competitive and very dynamic, with significant regulatory changes underway. As shown in Figure 6, installed capacity in New York ISO ("NYISO") totaled 44,513 MW in 2016.[35] This is more than 15 times of Hawaii's total installed capacity combined. New York's existing generation portfolio is dominated by gas and oil-fueled generating resources, representing approximately 64% of the state's total installed capacity and 44% of total energy generation.[36] These generating assets are required by state regulators to be ready to switch to fuel oil if the natural gas supply is constrained.[37] Nuclear facilities and hydro facilities (both conventional run-of-river and pumped storage) respectively account for 14% and 11% of total capacity.[38]

[34] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 3. Page H-53.

[35] S&P Global Market Intelligence. Regional Summary Statistics. <https://platform.mi.spglobal.com/web/client?auth=inherit#industry/summaryStatistics> Access Date: April 17, 2018.

[36] NYISO. *2017 Load & Capacity Data Report ("Gold Book").* April 2017.

[37] "New York State Profile and Energy Estimates." *US Energy Information Administration.* <https://www.eia.gov/state/?sid=NY>

[38] NYISO. *2017 Load & Capacity Data Report ("Gold Book").* April 2017.

Figure 6. New York electricity market snapshot

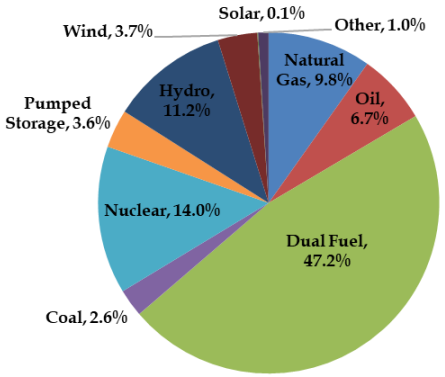
New York



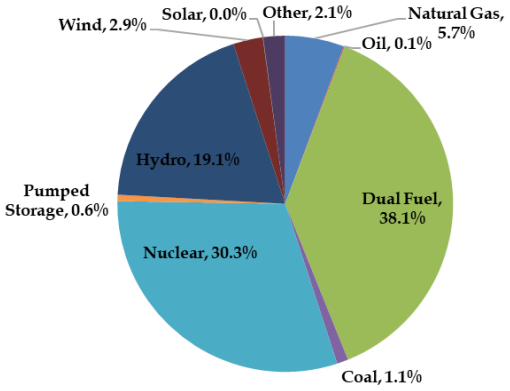
Key facts

Population (2016)	19.8 million
GDP growth (2016)	3.6%
Installed capacity (2016)	44.5 GW
Peak demand (2016)	32.1 GW
Load growth (2012-2016)	-0.3%
Generation (2016)	141 TWh
No. of utilities	6

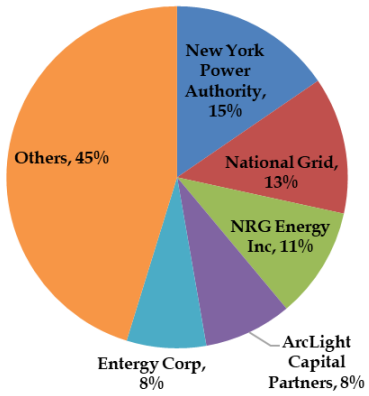
Installed capacity by fuel type (2016)



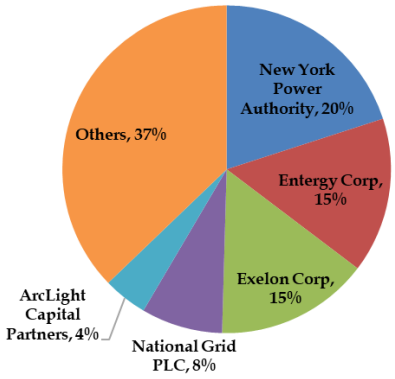
Generation by fuel type (2016)



Top players by installed capacity (2016)



Top players by generation (2016)



Note: The number of utilities refers to the total number of T&D utilities.
Sources: US Census Bureau. *State Population Totals and Components of Change: 2010-2017.* January 18, 2018; "Regional Data." *US Department of Commerce.* <https://www.bea.gov/iTable/index_regional.cfm>; S&P Global Market Intelligence; NYISO. *2017 Load & Capacity Data Report ("Gold Book").* April 2017. Department of Public Service. *Electric Utilities Listing.* <http://www3.dps.ny.gov/W/PSCWeb.nsf/All/03627EFC626529EE85257687006F39CD?OpenDocument>

New York electricity generators include both regulated electric utilities and independent power producers with diverse energy sources of generation.[39] The largest five generation owners in the NYISO market account for approximately 55% of total capacity.[40] The New York Power Authority ("NYPA"), a municipally owned generator and transmission owners, is the largest player in the market, accounting for 15% of the state's installed capacity. Other top generation market players include National Grid, NRG Energy, ArcLight Capital Partners, and Entergy.

Transmission assets are owned by eight (8) transmission owners ("TOs"), including six (6) investor-owned utilities ("IOUs") – Central Hudson Gas & Electric Corporation, Con Edison, Orange & Rockland, National Grid, NYSEG, and Rochester G&E – and two (2) power authorities – NYPA, which operates approximately one-third of the major transmission lines in the State,[41] and PSEG Long Island, which operates the Long Island Power Authority's transmission and distribution system.[42,43] The NYISO is the sole authority responsible for directing the operation of the New York State Power System, and coordinates with each TO's control center to maintain system reliability.[44]

In terms of distribution, New York State's IOUs, which are regulated by the NY Public Service Commission ("PSC"), are responsible for: (i) distributing electricity throughout the state; (ii) operating and maintaining their respective electric service distribution systems; (iii) responding to customer requests for service and maintenance; and (iii) serving as the electric service billing agent.[45] The only jurisdiction where electricity distribution does not fall under the responsibility of an IOU is in Long Island, where the Long Island Power Authority operates and maintains the electric distribution system through PSEG Long Island.[46]

There are some similarities between the New York and Hawaii markets. Both markets are operated in a single state. Both markets have increasing renewables in their energy mixes because of ambitious renewables goals, such as the RPS in Hawaii and the Clean Energy Standard ("CES")

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[39] EIA. *New York State Profile and Energy Estimates*. Web. <https://www.eia.gov/state/analysis.php?sid=NY>. Access Date: April 20, 2018.

[40] NYISO. *2017 Load & Capacity Data Report ("Gold Book").* April 2017.

[41] "Transmission Overview." *NYPA.* <https://www.nypa.gov/power/transmission/transmission-overview> Access Date: April 23, 2018.

[42] "Local Transmission Owner Planning Process." *NYISO.* <http://www.nyiso.com/public/markets_operations/services/planning/process/ltpp/index.jsp> Access Date: April 23, 2018.

[43] New York State Energy Planning Board. *Report on the Reliability of New York's Electric Transmission and Distribution Systems.* November 2000.

[44] NYISO. *Transmission and Dispatching Operations Manual 2016.* December 1, 2016.

[45] New York State Energy Planning Board. *Report on the Reliability of New York's Electric Transmission and Distribution Systems.* November 2000.

[46] "About Us." *PSEG Long Island.* <https://www.psegliny.com/page.cfm/AboutUs> Access Date: April 23, 2018.

in New York. According to the CES, 50% of New York's electricity should be generated from carbon-free renewable energy sources such as solar, wind, hydropower, and biomass by 2030 ("50 by 30 goal").[47] Both states support further growth of distributed energy resources ("DER"). Utilities' new role as "Distribution System Platform Providers" was designed to coordinate and facilitate deployment of various DERs on the grid.

However, the New York market and the Hawaii market are different in terms of market size and market structure. New York's electricity market is much larger than Hawaii's, as Hawaii's annual sales were only 6% of the annual sales in New York in 2016. Also, as mentioned above, New York's market is already a robust competitive wholesale and retail market, while the dominant utilities in Hawaii are vertically integrated and responsible for planning and dispatch. Moreover, the New York market is interconnected with numerous neighbors while Hawaii is isolated from the mainland and each island has its electric grid that is not connected with one another. However, we an assessment of the key components of Reforming the Energy Vision ("REV," as discussed below in Section 4.2.2 and 4.2.3) is merited and would still be valuable as part of this process.

4.2.2 Overview of New York's regulatory framework

In 1996, the New York NY PSC, which oversees the electric, gas, water, and telecommunication industries for the state, embarked on a restructuring of New York's electricity industry.[48] In doing so, the NY PSC sought to *"identify regulatory and ratemaking practices that [would] assist in the transition to a more competitive electric industry designed to increase efficiency in the provision of electricity, while maintaining safety, environmental, affordability, and service quality goals."*[49] Since then, the NY PSC has overseen the divestiture by the state's electric utilities of their generating facilities, the establishment of an independent system operator ("NYISO"), and the creation of competitive retail markets, which permit end-user customers to purchase electricity from energy service companies ("ESCOs").[50]

The NYISO was authorized to be established by FERC in 1998 and launched on December 1, 1999.[51] Its principal responsibilities include: ensuring the reliable operation of the bulk electricity grid of New York State, designing and implementing open and competitive wholesale electricity markets, and planning for New York's energy future.[52] Currently, the NYISO runs four markets:

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[47] 2015 New York State Energy Plan Frequently Asked Questions. Web. <http://energyplan.ny.gov/-/media/nysenergyplan/2015-faqs.pdf>

[48] The Association of the Bar of the City of New York. *Electric Regulation in the State of New York.* February 9, 2007.

[49] New York Public Service Commission. *Competitive Opportunities Regarding Electric Service, No. 94-E-0952.* March 6, 1996.

[50] The Association of the Bar of the City of New York. *Electric Regulation in the State of New York.* February 9, 2007.

[51] FERC. *Electric Power Markets: New York (NYISO).* Web. <https://www.ferc.gov/market-oversight/mkt-electric/new-york.asp>. Access Date: April 20, 2018.

[52] LEI. *LEI Semi-annual Regional Market Update and 10-year Energy and Capacity Price Forecast: New York.* 3rd Quarter 2017.

(i) energy market (both day-ahead and real-time); (ii) capacity market; (iii) ancillary services market (for regulation and reserve services); and (iv)Transmission Congestion Contracts market.[53] Since the NYISO was established in late 1999, the NYISO has taken operational control of the bulk power transmission system and the dispatch of generation in the State of New York.

Over the last 15 years, New York has strived to increase its renewable generation. In June 2002, the New York State Energy Planning Board released its 2002 State Energy Plan, which aimed to improve the State's use of renewable energy from 10% in 2000 to 15% in 2020.[54] In 2009, Governor Paterson announced the "45 by 15" Clean Energy Policy that proposed to reduce electricity end-use in 2015 by 15% below forecasted levels while simultaneously meeting 30% of the State's electricity supply needs through renewable resources.[55] Then, in April 2014, the NY PSC initiated a public proceeding to evaluate regulatory reforms. The objective was to "align electric utility practices and our regulatory paradigm with technological advances in information management and power generation and distribution."[56] In September 2014, New York City committed to 80 x 50, reducing greenhouse gas emissions by at least 80% by 2050.

Furthermore, Governor Andrew M. Cuomo laid out the REV strategy, "*to build a clean, resilient, and affordable energy system for all New Yorkers*" in 2015[57] He also directed the State Department of Public Service to design and enact a new Clean Energy Standard mandating that 50% of all electricity consumed in New York resulting from clean energy resources by 2030.[58] Currently, utilities in New York are transforming to become Distributed System Platform Providers ("DSPP"). Furthermore, under REV, market-based platform earnings and outcome-based earning opportunities will be added to the standard cost of service ratemaking approach.

4.2.3 History of transition and recent development

As described in the scope of work, the distribution-focused regulatory model is similar to the REV model that the electricity sector in New York State is transitioning into. This model targets are increasing the use of distributed energy resources ("DER") and improving customer participation in the electricity sector. Also, it is fundamentally shifting the role of the utility from an entity that develops and maintains transmission and distribution assets (utilities in New York

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[53] Ibid.

[54] New York State. *2002 New York State Energy Plan. Executive Summary*. Page S-3.

[55] Governor David A. Paterson. *2009 State Energy Plan Volume I*. December 2009. page 6.

[56] NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*. Order Instituting Proceeding. Issued and effective April 25, 2015.

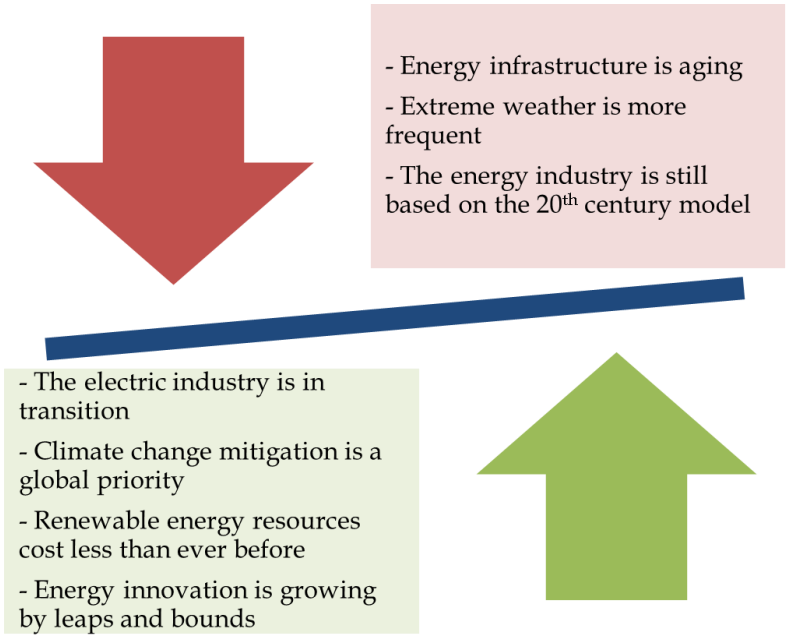
[57] Department of Public Service. New York State. *Reforming the Energy Vision*. Web. <http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument>. Access Date: April 20, 2018.

[58] New York State. *Governor Cuomo Directs Department of Public Service to Begin Process to Enact Clean Energy Standard.* Website. <https://www.governor.ny.gov/news/governor-cuomo-directs-department-public-service-begin-process-enact-clean-energy-standard>

generally are not allowed to own generation assets) to an entity that enables the localized management of electricity supply and demand.

As shown in Figure 7, REV was launched in part to help address concerns about aging energy infrastructure/regulatory model and the need to transition technologies and increase innovation. Similarly, Hawaii is facing the same challenges in its electricity sector. As discussed in Task 1.1.3, almost a third of the oil-fired generation capacity in Hawaii is from plants that are 40 – 49 years old, and more than a quarter of the plants are 50 years or older. Furthermore, as mentioned in its Order, the Hawaii PUC acknowledged that "*Hawaii's electric power industry is in the midst of a significant transition from predominantly centralized fossil-fuel-based generation systems towards increasingly distributed and renewable generation systems.*"[59] The Hawaii PUC also noted that "*Hawaii's regulatory framework must also continue to evolve to enable the State's electric utilities to meet these new challenges, maintain safety and reliability, offer new opportunities to create value for customers, and result in affordable rates.*"[60]

Figure 7. Reasons for regulatory reforms in New York



Source: New York State. About REV.

In April 2014, the NY PSC initiated a public proceeding to examine and evaluate regulatory reforms including two tracks:

[59] Hawaii PUC. *Instituting a Proceeding to Investigate Performance-Based Regulation*. (Order No. 35411). (Docket No. 2018-0088). page 1.

[60] Ibid, page 3.

- Track One focuses on the DSPP issues; and,
- Track Two focuses on regulatory changes and ratemaking issues.[61]

According to the NY PSC, utilities should take on the new role of DSPP and be responsible for "*planning and designing its respective distribution system in a manner that integrates DER as a primary means of meeting system needs.*"[62] This will require the DSPP to "*use localized, automated systems to balance production and load in real time while integrating a variety of DER, such as intermittent generation resources and energy storage technologies*."[63] Moreover, DSPPs are required to "*take steps to ensure that distribution systems continue to be modernized through the use of 'smart grid' technologies*" and "*coordinate its planning functions with the implementation by customers of customer-sited DER*."[64] Also, the Track One Order requires each utility, as a DSPP, to file a Distributed System Implementation Plan ("DSIP").[65] On June 30, 2017, New York's investor-owned utilities filed their first DSIPs, which include both a self-assessment of abilities to integrate distributed resources and a five-year roadmap. This will be updated every two years.[66]

It should be noted that the PSC received more than a thousand comments on its initial REV proposal and it was a lengthy process (April 2014 to February 2015) to determine the definition of DSPPs and their responsibilities.[67] Regarding implementation, the PSC initially proposed a phased approach to implementation, distinguishing among "near-term no-regrets" actions, traditional steps, and the planning and design of mature REV markets.[68] Stakeholders "overwhelmingly" supported a phased approach, but expressed their concerns including focus, timing, and resources required of the implementation process.[69]

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[61] NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Instituting Proceeding, (issued and effective April 25, 2014). Page 6.

[62] Ibid, page 12.

[63] Ibid, page 13.

[64] Ibid, page 14 - 15.

[65] NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting Regulatory Policy Framework and Implementation Plan, (issued February 26, 2015) (Track One Order). Page 32 and 129 - 130.

[66] Ibid, page 2.

[67] The PSC's initial proposal was released in April 2014 and the framework/implementation plan was adopted in February 2015.

[68] NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting Regulatory Policy Framework and Implementation Plan, (issued and effective February 26, 2015). Page 125.

[69] Ibid, page 126.

The PSC emphasized that "the pace of the REV initiatives reflects the challenges and circumstances"[70] that they face. Also, the PSC admitted that "a convergence of problems is clearly foreseeable, and the solution will be years in the making," but it is their responsibility to start right away.[71] Moreover, their approach is to "view the issues as comprehensive as possible, then to sequence the implementation in a manner that allows further progress to be informed by lessons learned."[72]

However, the NY PSC noted that possible effects the utility's involvement could be addressed not only through market rules but also through incentives to ratemaking that provides opportunities to utilities to use DER without regard to ownership.[73] The corresponding ratemaking and revenue model, as described in the Track Two Order, is based on the conventional COS ratemaking approach adding a combination of market-based platform earnings and outcome-based earning opportunities.[74] Utilities will have four ways of achieving earnings, including 1) traditional cost-of-service earnings, 2) earnings tied to achievement of alternatives that reduce utility capital spending and provide definitive consumer benefit, 3) earnings from market-facing platform activities; and 4) transitional outcome-based performance measures.[75] The Track Two Order initiated the following actions:[76]

1. Earning opportunities:
    - platform service revenues: revenues associated with the operation and facilitation of distribution-level markets;
    - earning adjustment mechanisms: incentives for system efficiency, energy efficiency, customer engagement, interconnection, affordability, etc.; and,
    - greenhouse gas reductions.
2. Competitive market-based earnings: unregulated utility subsidiaries are authorized to engage in competitive value-added services.

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[70] Ibid, page 127.

[71] Ibid, page 127.

[72] Ibid, page 128.

[73] NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Instituting Proceeding, (issued and effective April 25, 2014). Page 28.

[74] NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting A Ratemaking and Utility Revenue Model Policy Framework, (issued and effective May 19, 2016) (Track Two Order). Page 2.

[75] Ibid, page 2.

[76] Ibid, page 24 - 27.

3. Data access: utilities may charge a fee for the provision of more refined data or analysis.

4. Clawback reform: utilities are encouraged to displace capital expenditures with third-party DER investment where cost-effective.

5. Standby service: utilities begin a process to modernize the calculation of standby tariffs.

6. Opt-in rate design: utilities can voluntarily participate in advanced rate design including opt-in time of use rates and Smart Home rates.

7. Large customer demand charges: demand charges of commercial and industrial customers will be examined to see if they can be made more time-sensitive.

8. Scorecard metrics: a non-exclusive list of ten scorecard measures are adopted.

9. Mass-market rate design: an analytic approach to examine bill impacts.

As for customer data, the PSC believed that "utilities may not charge for basic levels of customer usage data shared with the customer or with vendors authorized by the customer," as this will "*reduce barriers to consumer use and is consistent with the objective to facilitate market development*."[77] However, for information beyond basic customer data, utilities may assess the charges and utilities may "*continue to charge energy service companies and other vendors for providing monthly customer data for a period in excess of 24 months*."[78]

4.2.4 Implications for Hawaii

For Hawaii, a transition similar to REV could be possible as it aligns with Hawaii's policy goals. However, Hawaii should also be realistic about what such a shift entails in terms of the timing, costs involved in the transformation, and additional or change in roles of the utilities and the PUC. Similarly, ratemaking initiatives need to be adapted to support such a regulatory transition.

The following lessons from New York's REV would be relevant to Hawaii:

- **The process of transitioning to the distribution-focused regulation model would be lengthy and complex.** As mentioned above, it will take years for a jurisdiction to transition to this relatively new model. Hawaii has similar active stakeholders' involvement in critical regulatory debates as New York, so a similarly long and complicated stakeholder process is likely if the PUC proposes to adopt a similar distribution-focused regulation model.

- **If the utilities take the role of DSPP, they should be restricted from owning DERs.** As discussed in REV's Track One Order, "ownership of generation by an affiliate of a utility

[77] Ibid, page 140.

[78] Ibid, page 140.

would unacceptably exacerbate the potential for vertical market power."[79] The NY PSC emphasized that this rationale also applies to "utility ownership of generation at the distribution level, where utilities are also operating distribution systems and retail-level markets for DER products.[80] This challenge exists in Hawaii as well. Currently, utilities own and manage the generation, transmission, and distribution, which results in vertical market power. If utilities take the role of a DSPP and they also continue to own DERs, it would result in even greater vertical market power and create more barriers for competitors to enter the market. Admittedly, this requirement is likely to be contentious and raise the thorny issue of what to do about existing assets owned by HECO Companies and thereby create stranded assets.

- **New ratemaking incentives should be created to attract utilities to optimize the use of DER without regard to ownership.** The utilities need to be paid for serving as DSPP. As discussed earlier, there are additional incentives provided to the NY utilities to perform this role.

4.3 Performance-based regulation model: United Kingdom

4.3.1 Overview of the UK market

The UK[81] electricity market is a mature, competitive market. It was among the first movers in power sector restructuring, and its market reform has generally been considered a success. Except for some old nuclear reactors, the entire sector is privately owned and fully unbundled, with privatization and unbundling beginning in the early 1990s. The current market design is structured around a bilateral market with a centralized balancing market. The retail electricity market is also fully liberalized, and consolidation between generators and retailers have created several large energy companies in the country. There are 149 licensed generators in the UK, led by Électricité de France ("EDF"), RWE Npower, Centrica, Drax, Scottish and Southern Energy ("SSE"), Uniper, InterGen, and ScottishPower.[82]

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[79] NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting Regulatory Policy Framework and Implementation Plan, (issued February 26, 2015) (Track One Order). Page 27.

[80] Ibid, page 27.

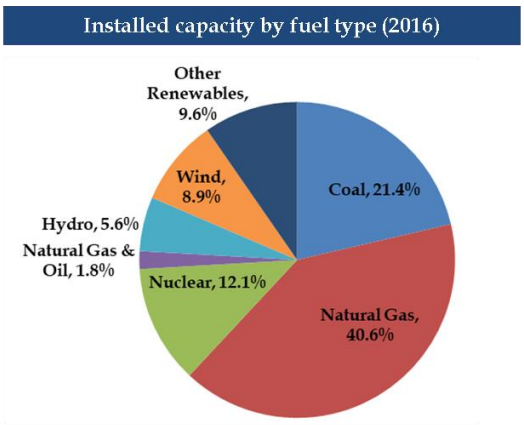
[81] In this report, we refer to the electricity market in the UK, excluding Northern Ireland, which runs on a separate network.

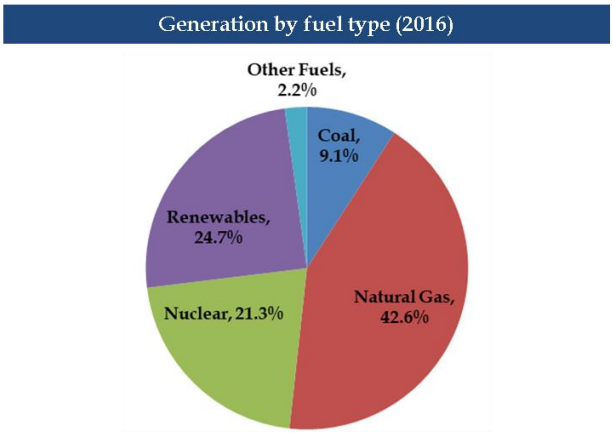
[82] Ofgem. *State of the Market Report*. October 31, 2017. P. 46.

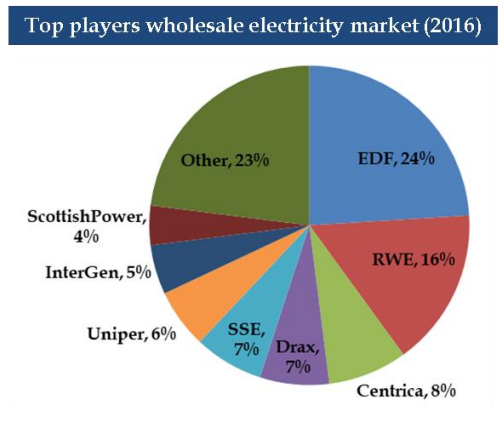
Figure 8. UK electricity market snapshot

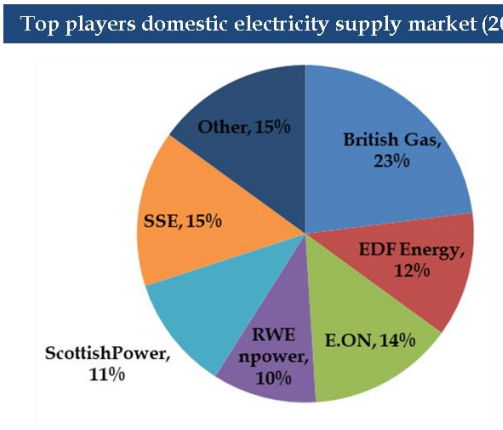


Key facts	
Population (2016)	65.6 million
GDP growth (2012-2016, annual average)	2.2%
Installed capacity (2016)	78.3 GW
Peak demand (2016)	52.9 GW
Load growth (2012-2016)	-1.7%
Generation (2016)	336 TWh
No. of electric distribution companies	14
No. of electric transmission companies	3









Sources: "United Kingdom." *The World Bank.* <https://data.worldbank.org/country/united-kingdom>; UK Department for Business, Energy & Industrial Strategy. *Digest of United Kingdom Energy Statistics (DUKES) 5.1, 5.5, 5.7, 5.10.* July 27, 2017; Ofgem. *State of the Market Report.* October 31, 2017.

The UK has a wholesale electricity market where generators sell electricity to suppliers through bilateral contracts, over-the-counter trades, and spot markets. It has been open to competition since 1990 with the creation of the Electricity Pool ("Pool"). The Pool was replaced with the New

Electricity Trading Arrangements ("NETA") in England and Wales and subsequently by the British Electricity Trading Transmission Arrangements ("BETTA") in April 2005, which extended the previous arrangements to Scotland and thus introduced a single wholesale electricity market for Great Britain.[83] In 2014, the government established the capacity market as part of its Electricity Market Reform policy, which is intended to help secure electricity supplies for the future.[84]

The transmission assets are owned and maintained by three regional monopoly transmission owners ("TOs"), namely: National Grid Electricity Transmission ("NGET") for England and Wales, Scottish Power Transmission Limited ("SPTL") for southern Scotland, and Scottish Hydro-Electric Transmission Limited ("SHETL") for northern Scotland and the Scottish islands groups.[85] These three TOs must ensure that sufficient transmission capacity is available to the UK transmission network. NGET is the sole system operator of the electricity transmission network and has the responsibility of ensuring that electricity supply and demand are balanced and the system remains within safe technical and operating limits. They are regulated by the Office of Gas and Electricity Markets ("Ofgem") through license conditions and price controls.

Currently, there are fourteen (14) licensed distribution network operators ("DNOs")[86] in the UK, and each is responsible for a distribution service area. These DNOs are owned by six different groups.[87] Similar to the TOs, the DNOs are also regulated by the Ofgem through license conditions and price controls. Most DNOs are part of a holding company, which is also involved in the generation and/or supply businesses.

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[83] "Glossary." *Elexon.* <https://www.elexon.co.uk/glossary/british-electricity-trading-and-transmission-arrangements/>

[84] Ofgem. *Capacity Market Rules*. Website. <https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-market-reform/capacity-market-cm-rules>

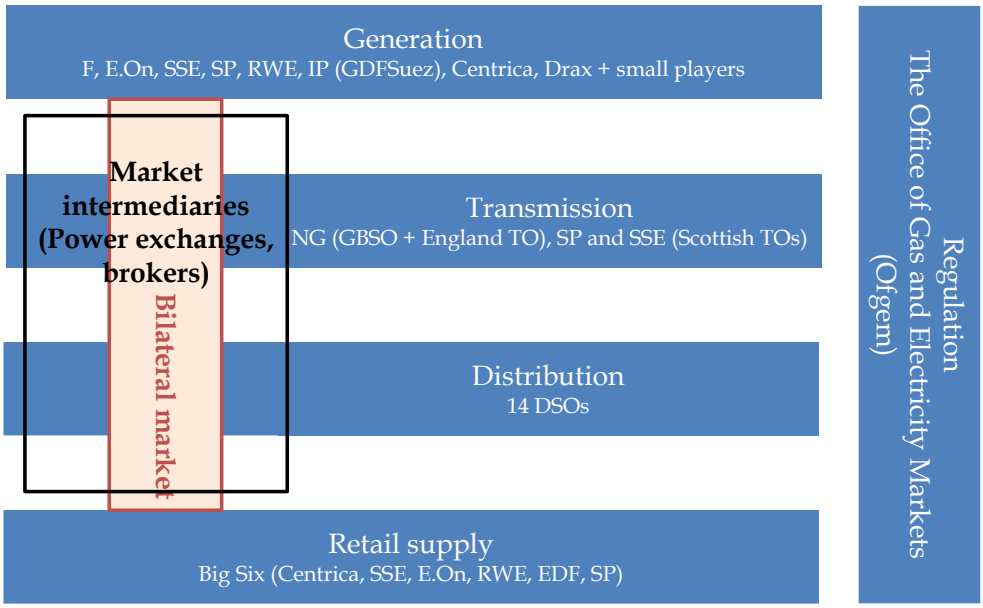
[85] These are the three onshore transmission owners ("TOs"). There are also offshore TOs. Source: "The GB Electricity Transmission Network." *Ofgem.* <https://www.ofgem.gov.uk/electricity/transmission-networks/gb-electricity-transmission-network>

[86] These DNOs include: Northern Powergrid (Northeast) Limited, Northern Powergrid (Yorkshire) plc, London Power Networks plc, South Eastern Power Networks plc, Eastern Power Networks plc, Electricity North West Ltd, Scottish Hydro Electric Power Distribution plc, Southern Electric Power Distribution plc, SP Distribution Ltd, SP Manweb plc, Western Power Distribution (East Midlands) plc, Western Power Distribution (West Midlands) plc, Western Power Distribution (South West) plc, and Western Power Distribution (South Wales) plc. Source: "The GB Electricity Distribution Network." *Ofgem.* <https://www.ofgem.gov.uk/electricity/distribution-networks/gb-electricity-distribution-network>

[87] These six (6) groups are composed of: (i) Electricity North West Limited, (ii) Northern Powergrid (owns Northern Powergrid (Northeast) Limited and Northern Powergird (Yorkshire) plc), (iii) SSE (owns Scottish Hydro Electric Power Distribution plc and Southern Electric Power Distribution plc), (iv) ScottishPower Energy Networks (owns SP Distribution Ltd and SP Manweb plc), (v) UK Power Networks (owns London Power Networks plc, South Eastern Power Networks plc, and Eastern Power Networks plc), (vi) Western Power Distribution (owns Western Power Distribution (East Midlands, West Midlands, South West, and South Wales) plc. Source: Ibid.

Electricity retail supply is legally separated from distribution. The major electricity suppliers—comprising six large vertically integrated suppliers[88] with a total combined market share of 82%—include British Gas, SSE,[89] E.ON, EDF Energy, Scottish Power, and RWE Npower (also known as the 'Big Six').[90] Competition among suppliers was introduced to improve quality of service to consumers, encourage consumer switching, and create pressure for lower and more innovative tariffs.

Figure 9. Relationship of the different sectors in the UK electricity market



Source: National Grid

There are some similarities between the UK and Hawaii markets. Both markets have increasing renewables in their energy mixes because of the introduction of environmental policies, such as the RPS in Hawaii and the renewable obligation ("RO"), which came into effect in 2002 in the UK.[91] The RO encourages investment of large-scale renewable electricity generating stations by setting an obligation on licensed electricity suppliers to source a portion of their supply from

[88] Integrated generation and supply businesses.

[89] Formed in 1998 with the merger of Scottish Hydro and Southern Electric.

[90] Ofgem. *State of the Market Report.* October 31, 2017. P. 20-21.

[91] "About the RO." *Ofgem.* <https://www.ofgem.gov.uk/environmental-programmes/ro/about-ro>

renewable sources.[92] Also, like Hawaii, over recent years the UK has witnessed *"a dramatic growth in the number of distributed generators seeking to connect to the distribution network*."[93]

Nevertheless, there are also stark differences between the two. For one, the UK has a larger electricity market than Hawaii. Hawaii's annual sales in 2016 represented 3% of the UK's yearly sales. Likewise, Hawaii's peak demand[94] represented 3% of the UK's peak demand[95] in 2016. Also, the UK has fully competitive markets in the generation and supply sectors, while Hawaii has a vertically integrated utility that dominates the generation sector in each county. Finally, the UK is a mature market in terms of restructuring, unbundling privatization, and market reforms, after having gone through several iterations of the market design. Hawaii, on the other hand, has undergone limited restructuring.

4.3.2 Overview of UK regulatory framework

The energy sector in the UK is governed by the Department of Energy and Climate Change ("DECC"), a ministerial department. The Gas and Electricity Markets Authority ("GEMA"), which operates through Ofgem, regulates the electricity and gas markets. This section provides a summary of the regulatory bodies in the UK energy market and their responsibilities.

DECC sets the electricity policies in the UK. It is responsible for ensuring that the market has a secure supply of energy by promoting policies that encourage investments in the UK's energy infrastructure. It also provides the delivery of low-carbon energy at the least cost to consumers.

Ofgem is the executive arm and the independent economic, regulatory body of the gas and electricity markets in the UK.[96] It is responsible for protecting consumers by promoting competition and regulating monopoly companies. Ofgem derived its regulatory powers from the Gas Act 1986, the Electricity Act 1989, and the Utilities Act 2000.[97] Ofgem's functions include administering a price control regime for network operators, monitoring the quality of services by setting guaranteed standards of performance and deciding upon proposed industry code changes. Ofgem operates under the guidance and governance of GEMA, which makes all major

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[92] Ofgem. *Renewables Obligation: Annual Report 2016-17.* March 21, 2018.

[93] Ofgem. *Distributed generation.* Website. <https://www.ofgem.gov.uk/electricity/distribution-networks/connections-and-competition/distributed-generation>. Access Date: June 28, 2018.

[94] 1,784 MW in 2016, source: DBEDT. *2016 State of Hawaii Data Book. Section 17 - Energy and Science*. 17.10 Electric Utilities, by island. 2016.

[95] 52,909 MW in 2016, source: UK Department for Business, Energy and Industrial Strategy. *Plant loads, demand and efficiency*. 2016.

[96] The Utility Regulator regulates the electricity, gas, and water sectors in Northern Ireland.

[97] Australia Competition and Consumer Commission. *Regulatory Practices in Other Countries Benchmarking opex and capex in energy networks.* May 2012.

decisions and sets policy priorities for Ofgem.[98] Ofgem also has the powers to investigate suspected anti-competitive behavior.

4.3.3 History of transition and recent developments

The UK uses a PBR regime in setting the electricity price[99] for the natural monopoly networks. Introduced in the early 1990s, the PBR used by the UK was in the form of an RPI-X cap mechanism where the RPI was the inflation in the Retail Price Index, and X was an efficiency factor. This meant that rates were allowed to increase by inflation minus an efficiency factor. Until 2010, the RPI-X values for P_0 and X were predetermined, and revenues were forced to conform to these annual changes.

The RPI-X regime was replaced by the current RIIO[100] model, which builds on its predecessor's success, but better meets investment and innovation challenges by emphasizing incentives to drive the innovation needed to deliver a sustainable energy network.[101] The DPCR5 was replaced by the RIIO-ED1 price control on April 1, 2015 and is set to extend until March 31, 2023. RIIO-ED1 sets the outputs that the 14 DNOs need to deliver for their consumers, as well as the associated revenues they are allowed to collect over the eight-year period.[102]

The UK's PBR has employed a "building blocks" approach that calibrates the terms of the indexing formula based on forward-looking revenue requirements of each regulated utility over the term of the price controls. In particular, revenue requirements are set based on estimates of the likely capital and operating costs and return of and return on an efficient asset base. Actual allowed revenues for each utility vary depending on how well it performs against some incentives. Figure 10 shows the components of revenue requirements under the UK's building blocks approach.

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[98] GEMA consists of non-executive and executive members. It determines the strategies, sets policies, and takes decisions on various matters such as price controls and implementation. Its powers are provided for under the Gas Act 1986, Electricity Act 1989, Utilities Act 2000, Competition Act 1998, and the Enterprise Act 2002.

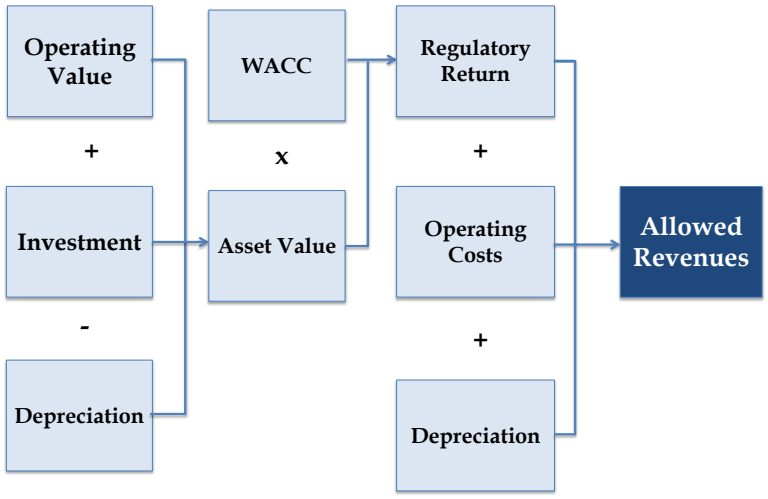
[99] Which they call "price control."

[100] Revenue = Incentives + Innovation + Outputs

[101] "Network Price Controls." *Ofgem.* <https://www.ofgem.gov.uk/electricity/distribution-networks/network-price-controls>

[102] "RIIO-ED1 Network Price Control." *Ofgem.* <https://www.ofgem.gov.uk/network-regulation-riio-model/current-network-price-controls-riio-1/riio-ed1-network-price-control>

Figure 10. Components of the allowed revenues



Source: Ofgem ("History of Energy Network Regulation")

In the UK, Ofgem uses the Information Quality Incentive ("IQI")[103, 104] scheme to further encourage TOs and DNOs to reveal their efficient costs and discourage inflated capital expenditure forecasts through a reward and penalty framework.[105] It provides incentives for a TO or DNO to not only propose efficient and prudent costs as part of its regulatory review but also to realize timely investment when needed (rather than to game the system to time investment with PBR terms). The IQI provides incentives by giving additional income to TOs or DNOs whose forecasts are close to Ofgem's assessment. This incentive is realized by providing TOs and DNOs with a higher incentive rate than those distributors with higher capex forecasts, thereby increasing their reward for outperformance.

The IQI, which has become a vital feature of the UK's approach, specifically addresses the information asymmetries problem that regulators have historically been concerned with under cost of service and also, to some degree, under the building blocks approach.

4.3.3.1 Transmission sector

Under the RIIO model, transmission operators are expected to deliver outputs that are set during the transmission price control review (i.e., RIIO-T1, which covers the period from April 1, 2013,

[103] Also referred to as the "sliding scale incentive" in previous regulatory periods.

[104] The IQI scheme was intended to mitigate the information asymmetry between Ofgem, the regulator, and the distributors in capex forecasting and provide incentives to distributors to provide the most efficient level of capex for the requirements of the network over the regulatory period. It aims to reduce the risk of under-investment, reduce the opportunity for distributors with high capex allowances to make high returns for underspend and reward distributors with low capex allowances for delivering against this.

[105] The Information Quality Incentive Mechanism is determined by the following formula:

(Allowed Expenditure – Actual Expenditure) * Efficiency Incentive + Additional Income

to March 31, 2021).[106] A list of these outputs is shown in Figure 11 below. Several of the incentives are linked to the percentage of allowed revenue.

Ofgem generally considers a TO's performance against its outputs on an annual basis. The productivity factor ("X-factor") in the UK is not the same as the X-factor in North American markets. The X-factor in the UK's RPI-X is not the productivity target, but instead the glide path in rates that allows the regulated utilities to recover reasonable return if – and only if – efficient costs are achieved. This glide path also allows for smoothing of rates for customers.

Figure 11. NGET's outputs and incentive parameters under RIIO-T1

Category	Output	Incentive
Safety	Compliance with safety obligations set by the Health and Safety Executive ("HSE")	Statutory requirements. No financial incentive A penalty/reward of 2.5% of the value of any over/under delivery of network replacement outputs
Reliability	Primary output based on Energy Not Supplied ("ENS")	Incentive rate of £16, 000/MWH which is based on an estimate of the value of lost load ("VoLL"). A collar on financial penalties limiting the maximum penalty to 3% of allowed revenues
Availability	Prepare and maintain a Network Access ("NAP")	Reputational incentive. Potential financial incentives if relevant during development and update of NAP
Customer Satisfaction	Develop customer/stakeholder satisfaction survey	Up to +/-1% of allowed revenue
	Effective stakeholder engagement	Up to 0.5% of allowed revenue via a discretionary reward scheme
Connections	To meet existing legal requirements	General enforcement policy
Environmental	SF_6 – Baseline target calculated annually with best practice 0.5% leakage rate for new assets installed	Differences to baseline subject to a reward/penalty based on the non-traded carbon price for carbon equivalent emissions
	Losses – Publish overall strategy for transmission losses and annual progress in implementation and impact on transmission losses	Reputational incentive
	Business Carbon Footprint ("BCF") – publish BCF accounts at business level annually over RIIO-T1	Reputational incentive
	Environmental Discretionary Reward Scheme ("EDR") scheme – measures to focus on aspects of the roles of the TOs and SO not explicitly captured in RIIO-T1 incentive	Positive reward available if achievement leadership performance across different scorecard activities.
	Visual amenity – to efficiently meet planning requirements for new infrastructure and deliver visual amenity outputs by mitigating impacts of existing infrastructure when it is located in designated areas	Reputational incentive in the context of its performance in the utilization of two mechanisms: (1) Baseline and uncertainty mechanism funding for additional cost of mitigation technologies required for development consent (2) Initial expenditure cap of £500m to reduce the impact of existing infrastructure in designated areas

Source: Ofgem. ("RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas")

[106] "Network Price Controls." *Ofgem.* <https://www.ofgem.gov.uk/electricity/transmission-networks/network-price-controls>

Ofgem reviews the TOs' capex forecasts to ensure that projected investments are adequate to maintain the operation of the network and to ensure that customers do not carry the costs of unnecessary investment or any operational inefficiency. Prior to the start of the regulatory period, TOs (as well as DNOs) are required to submit business plans that include, among other data, the utilities' forecasts for network replacement and capacity additions for the next five years. For the forecasted network replacement, Ofgem evaluates each utility's forecasts against its asset replacement policies in the past and the expenditure forecasts of other distributors taking into account the age profile of assets on the individual networks.

Financial models are also used by Ofgem and its consultants to evaluate whether the proposed projects are financeable under the regulatory term. According to Ofgem, financeability is evaluated via different financial ratios (like those used by rating agencies to determine the credit rating). If there are concerns, adjustments can be made to ensure that the utility can fund its operations.

Figure 12. Key components of PBR for the TOs

PBR components for UK for the RIIO-T1	
Form	Revenue cap
Approach	Building blocks approach
Term	8 years
Inflation factor (I factor)	UK Retail Price Index
Productivity factor (X factor)	Expected productivity improvements are embedded in the revenue requirements
Capex (K factor)	Embedded into the revenue requirements. Capital additions are included in the Regulatory Asset Value in the year of purchase of the assets. There is no distinction between new capex and opex when added into the RAV
Service Quality Standards (Q factor)	Rewards/penalties for specific performance targets (see table on NGET's outputs and incentive parameters under RIIO-T1)
Off-ramps	Reopeners are available for costs related to delivering EMR measures or for enhancement of physical security
Exogenous factor (Z factor)	Deviations in generation capacity connections from annual baseline profile and deviations in from baseline profile of investment (due to unanticipated demand connections)

Source: Ofgem. ("RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas")

4.3.3.2 Distribution sector

In 2015, Ofgem moved from the Distribution Price Control Review 5 ("DPCR5") approach to the RIIO-ED1 price control, the first electricity distribution price control to reflect the newly implemented RIIO model. RIIO-ED1, which covers the period from April 1, 2015, to March 31, 2023, requires DNOs to deliver on six (6) outputs: reliability and availability, connections,

environment, customer service and social obligations, safety, and innovation.[107,108] DNOs are also incentivized to manage their carbon footprints and report on how their actions have contributed to broader environmental objectives. A list of these outputs and incentives is shown in Figure 13 below.

Although the RPI-X framework worked well in the UK, Ofgem acknowledged that this framework was designed under a different context and may not work well in the future. Electricity networks were intended originally to deliver power from large, centrally-located power stations to homes and businesses around the UK. Electricity networks now need to be set up in such a way that electricity can flow to accommodate a higher number of smaller renewable plants that will connect to the networks. An Ofgem document also listed some of the challenges that distributors are likely to face: connecting more home-based micro generators, linking more small-scale renewables and combined heat and power ("CHP") to the low voltage distribution network, adapting to the impacts of climate change, and coping with active demand management.[109]

In the UK, there are several mechanisms in place to ensure that DNOs do not focus on cost-cutting measures at the expense of customer service. Some of the performance standards that are currently in place include: customer interruptions, customer minutes lost through interruptions each year, customer satisfaction, speed of providing quotes, speed of completing work to connect existing or new customers to their networks, percentage of units that are lost in distributing electricity to customers, and efficiency of connection of distributed generation. Distributors are rewarded or penalized if the targets set for these standards are not met. In designing the rewards and penalties for the target results, Ofgem uses the return on regulatory equity ("RORE")[110] as a measure of the DNOs' performance.[111] For the current period, Ofgem has also placed caps on the DNOs' exposure to each incentive, but it did not impose a cap on the extent to which DNOs can outperform the targets by being more efficient.[112]

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[107] "Network Price Controls." *Ofgem.* <https://www.ofgem.gov.uk/network-regulation-riio-model/current-network-price-controls-riio-1/riio-ed1-network-price-control>

[108] Ofgem. *RIIO-ED1 Annual Report: 2016-17.* December 19, 2017.

[109] Ofgem, *Regulating Networks for the Future RPI-X 20 Emerging Thinking,* (London: 2010), p. 36 and Ofgem, *RIIO – A New Way to Regulate Energy Networks,* (London: Ofgem, 2010), p. 1.

[110] The RORE is also used to determine the cost of capital.

[111] For instance (and as discussed in the *Ofgem Electricity Price Control Review Final Proposal*),[111] if all companies match the customer minutes lost performance currently achieved by the most efficient distributor, and were able to achieve their own best customer interruptions performance from the previous regulatory period in every year of the current regulatory period and earn the cap on losses and customer satisfaction, then they would be able to earn around another 110 to 220 basis points over the period. Given the WACC for the current regulatory period is at 4.7%, this would mean that shareholder returns at over 10% for all DNOs.

[112] *Ibid.* p. 56.

There are also re-openers or "logging up mechanisms" for distributors during special circumstances to ensure that both the distributors and consumers are protected from differences between the actual and assumptions underpinning the price control.[113] The PBR also has flow-through mechanisms to ensure that costs beyond the DNOs' control are covered and passed through to customers. There are also incentives to invest in technological improvements.

Figure 13. DNO's outputs and incentive parameters under RIIO-ED1

Category	Output	Incentive
Reliability and availability	Improvements in network reliability measured through the number of customer interruptions and the duration of these interruptions	Interruptions Incentive Scheme ("IIS") incentivizes DNOs to reduce the frequency and duration of interruptions experienced by customers
Connections	Sets targets related to time required to quote connections to customers and the time taken to actually connect customers	Time to Connect Incentive ("TTC") incentivizes DNOs to connect customers in a timely and efficient manner; Incentive on Connections Engagement ("ICE") incentivizes DNOs to meet the needs of larger connection customers, i.e. unmetered, generation and higher-voltage demand customers
Environment	Includes reducing BCF, SF_6 emissions and oil leakage from fluid-filled cables	Reputational incentives such as the Losses Discretionary Reward ("LDR") scheme
Customer service and social obligations	DNOs are to engage proactively with stakeholders in order to anticipate their needs and to deliver a consumer-focused, socially responsible and sustainable electricity service	Broad Measure of Customer Service ("BMCS"), which is comprised of the Customer Satisfaction Survey, Complaints Metric, and Stakeholder Engagement and Consumer Vulnerability ("SECV")
Safety	DNOs must be compliant with standards set by the Health and Safety Executive ("HSE")	
Innovation	DNOs are to achieve Ofgem's vision of innovation being central to the transition to a low carbon economy	Network Innovation Allowance ("NIA"), which funds smaller scale research, development and demonstration projects; Network Innovation Competition ("NIC"), an annual competition which provides funding to a small number of large-scale innovation projects; Innovation Roll Out Mechanism ("IRM"), which facilitates the roll out of proven innovations

Source: Ofgem. *RIIO-ED1 Annual Report: 2016-17*. December 19, 2017.

4.3.4 Implications for Hawaii

Clearly, the long history of reforms in the UK energy sector points to the crucial role that policy plays in pursuing the market's objectives. Policy reforms have been borne out of deeper market appreciation, more profound dialogue and consensus-building, and a stronger call for low-carbon development. The UK example presents a credible case for the merits of PBR. However, this requires an independent and transparent regulatory environment and the strong commitment and co-operation of system operators, utilities, and consumers. Hawaii can learn from the UK's experience in effectively implementing the PBR approach. Below are useful insights and lessons learned, from the UK experience:

- **Provide clear objectives for electricity reforms or any other regulatory changes upfront**. The UK was transparent with its goals in its 1990 restructuring. Providing a clear path

[113] Ofgem. *Electricity Distribution Price Control Review Final Proposals – Cost Assessment*. London: Ofgem, 2009, p. 6.

allows industry players to prepare for the changes in the marketplace. Also, these reforms and transitions require a gradual process which will take a few years.

- **Establish performance standards and quality of service**. The UK's use of performance targets combined with a penalty and reward incentive system has improved the quality of service of DNOs. HI currently has some performance incentive mechanisms where rewards and sanctions are imposed if targets are not achieved.

- **Adapt to the changing environment.** The framework for the electricity transmission and distribution price controls has changed significantly when compared with the regime that was put in place at privatization. Ofgem routinely makes modifications to the PBR regulations after each regulatory period to adapt to changes in the environment or improve a particular mechanism that did not work as anticipated. However, some would argue that the changes have been too frequent without corresponding benefits.

- **Recognize what works and what does not work**. In the original provision of the price controls implemented at privatization, revenues for distributors were allowed to increase in line with the number of units distributed. However, Ofgem recognized that this arrangement had the unintended effect of incentivizing distributors to increase the volume of units distributed. To address this, changes to the revenue driver mechanism were implemented in the next regulatory period under which the influence of units distributed was reduced to a weight of 50%, with the other 50% linked to customer numbers.

- **Provide incentives to encourage cost efficiency and quality service in its PBR.** Ofgem has put in place incentives for TOs and DNOs, so they can continue to innovate, deliver services efficiently, and provide an appropriate level of network capacity, security, reliability, and quality of service. Some of these incentives include a low carbon networks fund, distributed generation incentive, customer satisfaction incentive, customer reward scheme, innovative funding incentive, and the IQI. TOs and DNOs are also able to keep some of the benefits if the business can operate at a lower cost or exceed target levels—of performance standards or customer service—at the same cost.[114] Hawaii's PUC, in Order 35411, stated some of these items namely greater cost control and reduced rate volatility, efficient investment and allocation of resources, fair distribution of risks between utilities and customers, and fulfillment of State policy goals as the targeted results of the PBR design in the State.

4.4 Lighter regulation for co-op: Alaska

As stated in Task 2.1.1, the Project Team evaluated a separate regulatory model for KIUC – one with lighter PUC oversight compared to the status quo. Correspondingly, the Project Team

[114] In fact, the Ofgem reported that for the 2010-2015 period, well performing distributors could earn up to 13% equity returns within the regulatory period.

reviewed Alaska as a case study for this model as Alaska is mostly served by co-ops[115] and it has some similarities with Hawaii as discussed below.

4.4.1 Overview of the Alaska market

Alaska's electricity market is regulated, and the Regulatory Commission of Alaska ("RCA") oversees the state's electric utilities. The electric infrastructure in Alaska differs from that of the other jurisdictions outlined in this report, as well as that of most of the conterminous United States. While Alaska does have an interconnected grid, the Railbelt, which serves the most densely populated area of the state (approximately 75% of the population) from Fairbanks to south Anchorage, the grid is not linked to large, interconnected grids in the Lower 48 states or Canada through transmission and distribution lines.[116] Rather, the network in Alaska is a "*patchwork of unconnected grids,*" attributable to Alaska's overall low population density as well as distances between population centers.[117] This is somewhat similar to Hawaii, as each of Hawaii's islands has its own electrical grid, not connected to any other island. Furthermore, as depicted in Figure 14, the installed capacity in Alaska totaled 2,742 MW in 2016, similar to that of Hawaii.[118] The existing generation portfolio is largely dominated by natural gas, which accounted for approximately 48% of utility-scale generation in 2016. This is followed by 26% from conventional hydro, 13% from petroleum liquids, and 9% from coal, and 7% from other renewables, including wind and biomass.[119]cooperatives

Alaska's electricity utilities include investor-owned utilities ("IOUs"), municipally-owned/publicly-owned utilities, and member-owned electric cooperatives. Over 90% of Alaska's electricity supply is provided by vertically-integrated utilities. Collectively, Anchorage Municipal Light & Power, Chugach Electric Association (cooperative), Matanuska Electric Association (cooperative), Golden Valley Electric Association (cooperative) own 1,610 MW or approximately half of the state's total installed capacity. The four utilities also provide generation, transmission, and distribution electricity services in Alaska (Figure 15).

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[115] More than 74% of retail customers are served by co-ops in Alaska. (Source: S&P Global Market Intelligence Database.)

[116] "Alaska State Profile and Energy Estimates." *US Energy Information Administration.* <https://www.eia.gov/state/analysis.php?sid=AK> Access Date: July 4, 2018.

[117] Rábago, K.R., Feiler, T., and Damron, F. *Report to: The Alaska Public Utilities Commission and the Alaska State Legislature – Study of Electric Utility Restructuring in Alaska.* CHM2HILL and Econergy International Corporation.

[118] "State Electricity Profiles – Alaska Electricity Profile 2016." *US Energy Information Administration.* <https://www.eia.gov/electricity/state/alaska/index.php> Access Date: July 4, 2018.

[119] U.S. Energy Information Administration. *Electric Power Annual 2016.* Tables 3.7-3.22. <https://www.eia.gov/electricity/annual/pdf/epa.pdf>

Moreover, two of the five largest plants by capacity (i.e., 300 MW and 170 MW) are owned by Chugach Electric Association.[120] Of the five largest plants, four are natural gas-fired, with the fifth being petroleum-fired plant.

Furthermore, Alaska has limited electric transmission infrastructure. There are approximately 2,045 miles of transmission lines with the majority being less than 230 kV. Major transmission owners include Anchorage Municipal Light & Power, Golden Valley Electric Association, Copper Valley Electric Association, and Matanuska Electric Association. Together, the four vertically-integrated utilities serve approximately 217,000 customers or over 30% of Alaska's population.

There are some similarities between the Alaska and Hawaii markets. First, both states have dispersed grids that are not interconnected with that of neighboring markets due to the states' remote location. With regards to the use of petroleum liquids, a majority of Alaska's rural communities do not have access to the Railbelt[121] and thus, rely on consumer-owned electric cooperatives, many of whom produce some or all of their electricity from diesel.[122] This places Alaska second to Hawaii in terms of per capita generation of electric power from petroleum liquids in the US.[123,124]As such, the Hawaii and Alaska electricity markets rank as the nation's top two markets in terms of electricity generation per capita from petroleum liquids, with Alaska ranking second after Hawaii.[125] Similar to Hawaii, the dominant players in Alaska are vertically integrated utilities. Lastly, both markets are exempted from the Federal Power Act and do not have electric reliability organizations affiliated with the NERC, and also do not fall under the jurisdiction of the FERC.[126]

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[120] U.S. Energy Information Administration. *Annual Electric Generator Report.* Form EIA-860

[121] The Railbelt is an interconnected grid that serves the densely populated areas from Fairbanks to the south of Anchorage. The Railbelt utilities are comprised of six utilities, namely Chugach Electric Association, Anchorage Municipal Light & Power, the City of Seward, Homer Electric Association, Matanuska Electric Association, and Golden Valley Electric Association. (Source: "ISO Update." *Renewable Energy Alaska Project (REAP).* September 29, 2017. Web. August 10, 2018. < https://alaskarenewableenergy.org/index.php/2017/09/29/iso/>

[122] "Alaska State Profile and Energy Estimates." *US Energy Information Administration.* <https://www.eia.gov/state/analysis.php?sid=AK> Access Date: July 4, 2018.

[123] U.S. Energy Information Administration. *Electric Power Annual 2016.* Tables 3.7-3.22. <https://www.eia.gov/electricity/annual/pdf/epa.pdf>

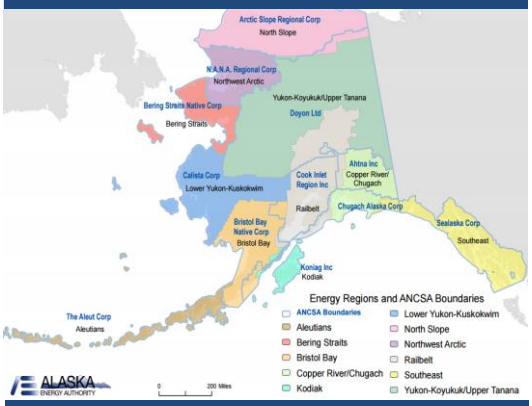
[124] "Alaska State Profile and Energy Estimates." *US Energy Information Administration.* <https://www.eia.gov/state/analysis.php?sid=AK> Access Date: July 4, 2018.

[125] "Alaska State Profile and Energy Estimates." *US Energy Information Administration.* Web. Access date: July 5, 2018. <https://www.eia.gov/state/analysis.php?sid=AK>

[126] NERC. *H.R. 6 – 348.* <https://www.nerc.com/AboutNERC/keyplayers/Documents/HR6_Electricity_Title.pdf>

Figure 14. Alaska electricity market snapshot

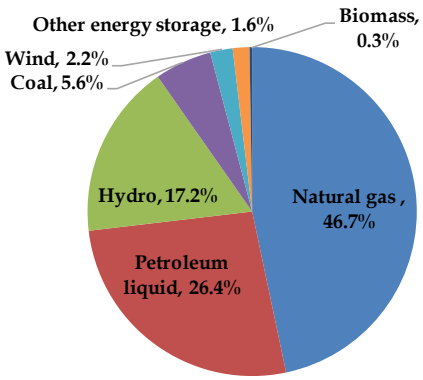
Alaska



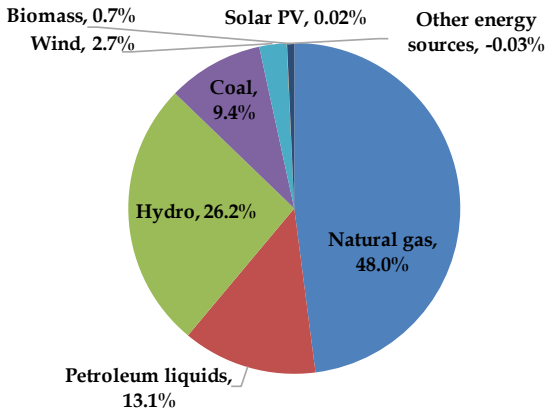
Key facts

Population (2016)	0.7 million
GDP growth (2016)	-4.5%
Installed capacity (2016)	2.7 GW
Peak demand (2016)	1.2 GW*
Load growth (2012-2016)	-0.9%
Generation (2016)	6.34 TWh
No. of utilities	8

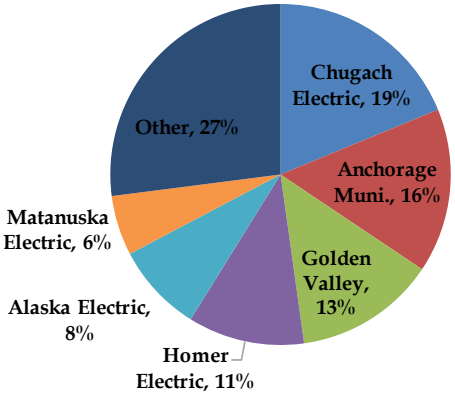
Installed capacity by fuel type (2016)



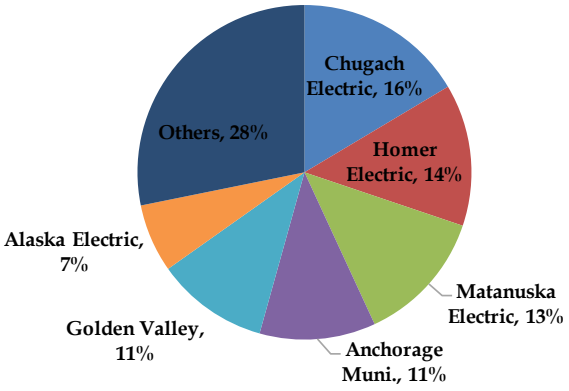
Generation by fuel type (2016)



Top players by installed capacity (2016)



Top players by generation (2016)



Note: *Peak demand listed is non-coincident peak demand. The number of utilities refers to the total number of T&D utilities.

Sources: US Census Bureau. *State Population Totals and Components of Change: 2010-2017.* January 18, 2018; "Regional Data." *US Department of Commerce.* <https://www.bea.gov/iTable/index_regional.cfm>; US Energy Information Administration.

Figure 15. Utilities providing generation, transmission, and distribution electricity services in Alaska

	Anchorage Municipal Light & Power	Golden Valley Electric Association (Co-op)	Chugach Electric Association Inc. (Co-op)	Matanuska Electric Association (Co-op)
Service territories	Anchorage	Fairbanks, Delta Junction, Nenana, Healy and Cantwell	Area extending from Anchorage to the northern Kenai Peninsula, and from Whittier on Prince William Sound to Tyonek on the west side of Cook Inlet	South of Cantwell down to Eagle River and over to the Matanuska Glacier
Miles of transmission lines owned	N/A – 371 circuit miles of distribution lines	N/A; 3,229 miles of power lines (T&D)	434; 2,153 miles of power lines (T&D)	N/A; 4,200 miles of power lines (T&D)
Numbers of customers served	30,751	44,374	83,855	58,000
Customer profile	15% residential, 85% commercial	29% residential, 71% commercial	Mainly residential	67% residential, 33% commercial
Approved rate of return	4.88%	N/A	N/A	N/A
Regulatory framework used to determine transmission rate	Cost of service	Cost of service	Cost of service	Cost of service
Major ongoing infrastructure projects	N/A	N/A	Full Advanced Metering Infrastructure (AMI) meter deployment by Spring 2017	Wasilla Transmission 115 kV Line

Source: Chugach Electric Association Inc. *Chugach 2016 Annual Report;* Golden Valley Electric Association. *At a Glance.* 2016; Matanuska Electric Association. *2015 MEA Annual Report*.

Nonetheless, unlike Hawaii where most of the customers are served by an IOU (i.e., HECO Companies, except the County of Kauai), over 74% of retail customers in Alaska are served by co-ops. Moreover, the two markets differ significantly with regards to renewable goals. Unlike Hawaii, Alaska has no formal policy targets for emissions reduction or renewables expansion. More specifically, Alaska has no established RPS or other forms of renewables target policy, as well as no established Greenhouse Gas ("GHG") reduction policy objectives.

4.4.2 Overview of the regulatory framework in Alaska

Like Hawaii, Alaska is outside of FERC's jurisdiction. As mentioned in Section 4.4.1, the RCA oversees the operations of the electric utilities in Alaska. As per Alaska Statute ("AS") 42.05.141, the responsibilities of the RCA include, but are not limited to, the following:[127]

- regulate public utilities that conduct utility business in the state;

[127] AS 42.05.141. *General Powers and Duties of the Commission.* Access date: July 5, 2018. <http://www.touchngo.com/lglcntr/akstats/statutes/title42/chapter05/section141.htm>

- investigate matters concerning rates, regulations, practices, and services, for instance, of public utilities and hold hearings, as necessary;
- establish or govern rates, regulations, methods, and services, for example, such that they are fair and reasonable;
- regulate the service and safety of operations of public utilities;
- require public utilities to file reports; and
- perform duties as per AS 42.45.100 – 42.45.190.

This is similar to the responsibilities of the Commission in Hawaii, which oversees the operations of electric utilities in the State. Like the RCA, the PUC partakes in activities such as rate regulation, monitoring availability, service quality, and reliability.

4.4.2.1 Regulated cooperatives

For cooperatives formed under AS 10.25 that are regulated by the RCA, cooperative utilities are subject to simplified rate filing ("SRF") procedures. SRF allows both the cooperatives and the RCA to avoid the costs and time associated with traditional general rate cases.[128] Under Article 6 of the Alaska Admin Code ("AAC"), *Simplified Rate Filing Procedures for Electric Cooperatives*, a cooperative may adjust its rates not more than four times a year (i.e., on a quarterly basis). Under the SRF procedure, the board of directors holds a major responsibility in rate adjustments rather than the RCA; that being said, the cooperative must first submit filings to the RCA before implementing any rate changes.[129] As per AAC 48.710(b), a cooperative must file on a quarterly or semi-annual basis (whichever period is opted for) with the RCA information including, but not limited to: RCA Form 201[130]; a schedule and explanation of amortized expenses, pro forma and normalizing adjustments, and of each line on RCA Form 201 which has increased or decreased over 10% from the previous 12-month period"; "*calculation of the cooperative's Times Interested Earned Ratio ("TIER") [as per] 3 AAC 48.750*"; "*the ratio of residential class kilowatt-hour sales to total kilowatt-hour sales for the current 12-month period and the ratio that existed when the cooperative last filed a [COS] study*"; if appropriate, "*the ratio of retail kilowatt-hour sales as a percentage*

[128] "Simplified Rate Filing." *Chugach.* Web. July 5, 2017. <https://www.chugachelectric.com/about-us/regulatory-affairs/simplified-rate-filing>

[129] Ibid.

[130] RCA Form 201 is a modified version of the Rural Electrification Administration ("REA") Form 7, or the Rural Utilities Service ("RUS") Form 7 (the RUS absorbed REA and its responsibilities in 1994). While a version of the RCA Form 201 is not available, the RUS Form 7 is a Financial and Statistical Report that includes, but is not limited to, the following: statement of operations, data on transmission and distribution plant, balance sheet, notes to financial statement, changes in utility plant, materials and supplies, service interruptions, employee hours and payroll statistics, patronage capital, due from consumers for electric service, kWh purchased and total cost, long-term leases, annual meeting and board data, long-term debt and debt service requirements, annual summary of power requirements data base, investments, and loan guarantees. (Source: AAC 48.710; United States Department of Agriculture Rural Utilities Service. *Financial and Statistical Report.* Web. July 24, 2018. <http://www.nmprc.state.nm.us/utilities/docs/form7-2006.pdf>)

of total retail and wholesale kilowatt-hour sales, and the ratio that existed when the cooperative filed its last [COS] study"; and a "*copy of the cooperative's annual certified audit, including any adjusting journal entries*".[131]

These filings may result in an increase in rates, a decrease in rates, or in unchanged rates. While the decrease in rates is not limited, the increase is capped. More specifically, cooperatives "*may not exceed a cumulative [20%] increase in any three-year period, or a cumulative [8%] in any 12-month period, excluding purchased power and fuel costs rate adjustments.*"[132]

4.4.2.2 Deregulated cooperatives

In Alaska, cooperatives may be exempt from the regulation of RCA or deregulated. As per AS 42.05.712, *Deregulation Ballot*, an election may be called upon by the board of directors of a cooperative upon a valid petition from members; the petition must not be signed by less than "*the number of [members] equal to [10%] of the first 5,000 [members] and [3%] of the [members] in excess of 5,000.*"[133]

A majority vote with at least 15% of eligible members voting is required for a co-op to be deregulated (i.e., exempt from the regulations of the RCA).[134] Each member of the co-op must receive a notice with the regular bill for service a minimum of 60 days before the date of the election, which must contain information regarding the election on the option of deregulation or regulation from under the RCA and that each member is entitled to vote. The notice also includes any announcements regarding public meetings where members would have the opportunity to discuss the matter; said meetings would not be held more than 30 days before the ballots are mailed. This vote must be submitted within 30 days from receipt of the information and results are certified within the 60 days after the ballots are sent to members.[135]

While cooperatives may be re-regulated (if members vote in favor of regulation), it must be noted that an election may be only held every two years. There have been seven electric co-ops that voted for re-regulation. Most recently, Egegik Light and Power voted to be reregulated in 2002.[136]

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[131] "Article 6 Simplified Rate Filing Procedures for Electric Cooperatives." *Alaska State Legislature.* Access date: July 4, 2018. <http://www.legis.state.ak.us/basis/folioproxy.asp?url=http://wwwjnu01.legis.state.ak.us/cgi-bin/folioisa.dll/aac/query=[jump!3A!27title3chap48!2C+a!2E+6!27]/doc/{@10154}?next>

[132] 3 AAC 48.770. *Limitations on use of simplified procedure.*

[133] AS 42.05.712. Deregulation Ballot. Access date: July 5, 2018. <http://www.touchngo.com/lglcntr/akstats/Statutes/Title42/Chapter05/Section712.htm>

[134] Ibid.

[135] Ibid.

[136] "Deregulation/Reregulation Elections." *Regulatory Commission of Alaska.* Web. Access date: July 6, 2018. <http://rca.alaska.gov/RCAWeb/RCALibrary/DeregulationElections.aspx>

Once deregulated, cooperatives are no longer regulated by the RCA except AS 42.05.221 to AS 42.05.281.[137] Instead, co-ops are governed by the board of directors. Conversely, in the case of KIUC in Hawaii, all rates, schedules, rules and practices made or charged by public utilities are required to be filed with the PUC.[138]

AS 42.05.712, *Deregulation Ballot* became effective on August 14, 1980, which was initially in the AS. Information about the history and transition is not publicly available, but a detailed discussion on sample cooperatives that moved to deregulation will be discussed in Section 0.

4.4.3 Implications for Hawaii

Several lessons from Alaska's electricity market, particularly about cooperatives, can be considered for Hawaii. More specifically, the PUC could consider lighter regulation of cooperatives as done by the RCA in Alaska, either via means of voluntary deregulation and/or by the introduction of a simplified and expedited ratemaking process for cooperatives. Below are key insights from Alaska's experience that could be considered:

- **Deregulation does not need to be an "either-or" option; it can take place in different forms.** There are many options for KIUC, ranging from "simplified ratemaking/ investigation process" to complete deregulation. This means that some of the areas that are currently regulated by the PUC could be relinquished. These can include rate governance, ratemaking, and/or filing annual reports. Whether "lighter regulation" or "complete deregulation" would work depends on various factors, including but not limited to, political will, economic benefits, opinions from the community, etc. This would need to be separately considered and analyzed before Hawaii could make any serious decisions about opting for a lighter regulation for co-ops.

- **Should the Hawaii Legislature decide to introduce optional deregulation for cooperatives (or smaller utilities), it should do so with caution.** Prior to offering KIUC lighter regulation, the Legislature and PUC must ensure that appropriate safeguarding mechanisms are in place to protect customers of the electric cooperative. Moreover, as mentioned in Section 4.4.2.2, for an electric cooperative to be deregulated under the RCA in Alaska, a majority vote with a minimum of 15% eligible members voting most occur.[139] To ensure the representativeness of the decisions, the Legislature should set up appropriate rules and percentages for qualified voting. The option of "re-regulation" via voting is another way to protect the customers' interests. Also, other rules might need to

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[137] AS 42.05.221 *Certificates Required;* AS 42.05.231 *Application;* AS 42.05.241 *Conditions of Issuance*; AS 42.05.251 *Use of Streets in Municipalities*; AS 42.05.254 *Public Utility Regulatory Cost Charge*; AS 42.05.261 *Discontinuance, Suspension, or Abandonment of Certificated Service*; AS 42.05.271 *Modification, Suspension, or Revocation of Certificates*; and AS 42.05.281 *Transfer of Certificate.* (Source: "Chapter 5. Alaska Public Utilities Regulatory Act." *Alaska Statutes.* Web. Access date: July 5, 2018. <http://www.touchngo.com/lglcntr/akstats/Statutes/Title42/Chapter05.htm>

[138] HRS § 269-16(a).

[139] Ibid.

be set up to protect customers of partial-deregulated or deregulated cooperatives. For instance, in Colorado (another case that will be analyzed in Section 0), the PUC may resolve complaints from individual customers of deregulated electric cooperatives for certain issues such as discrimination or preferential treatment of a group of customers.[140]

- **KIUC may consider proposing simplified regulatory processes to the Hawaii PUC if legal changes are challenging and time-consuming.** To minimize costs and time associated with lengthy regulatory procedures, KIUC may propose simplified regulatory processes on specific topics to the Hawaii PUC. Like in Alaska, cooperatives use simplified rate filing, enabling them to make reasonable adjustments to demand and energy rates without filing a formal rate case to the Commission.[141]

[140] Colorado PUC. *Deregulated Electric Cooperatives in Colorado.*

[141] "Simplified Rate Filing." *Chugach.* Web. July 5, 2017. < https://www.chugachelectric.com/about-us/regulatory-affairs/simplified-rate-filing>

5 Markets that have changed regulatory models in the past 20 years

This section provides an analysis of some of the jurisdictions that have changed regulatory models in the past twenty years. Since New York State, the only jurisdiction that is currently transitioning to the distribution focused regulatory model [142] was already discussed in Section 4.2; the Project Team will not discuss examples for the distribution focused regulatory model. Therefore, the focus of this section is on examples for the ISO model, PBR, and Lighter Regulation in this section.

To identify examples of the ISO model, the Project Team reviewed all the ISOs in North America, including their establishment year and jurisdictions (states or provinces coverage). Other than ERCOT, which was discussed in Section 4.1, the Project Team believes that California ISO ("CAISO"), Ontario's Independent Electricity System Operator ("IESO"), and Alberta Electric System Operator ("AESO") would be good points of comparison for Hawaii because they are markets that represent a single jurisdiction. Furthermore, some of them have similarly ambitious environmental policies.

Figure 16. Summary of selected markets that have changed regulatory models to ISOs, PBR, and lighter regulation for co-ops

Market	Regulatory model	Number of Utilities	Number of customers	Capacity (MW)	Annual sales (MWh)	Average retail rates (cents/kWh)
California	ISO	14	16,029,429	70,960	284,119,456	14.68
Alberta	ISO/ PBR	11	1,750,000	16,423	79,560,000	8.11
Ontario	ISO/ PBR	71	5,106,528	36,070	130,194,307	12.23
Australia	PBR	21	6,755,510	42,862	196,500,000	19.22
The Philippines	PBR	130	18,519,029	21,423	74,153,000	16.03
Malaysia	PBR	3	9,659,221	26,563	124,709,000	8.66
Colorado	Lighter regulation	6	2,643,315	16,078	54,802,037	9.83
Utah	Lighter regulation	1	1,175,934	8,976	30,179,534	8.72

Note: 2016 numbers. Average retail rates are in US dollars. The number of customers refers to the total number of customers (approximate), and the number of utilities refers to the total number of T&D utilities.
Source: S&P Global. IESO. AESO. Natural Resources Canada.

As for jurisdictions that have changed to PBR models, the Project Team included in the list Australia, the Philippines, and Malaysia. The Philippines and Malaysia were included in the list because these markets have some resemblances to Hawaii, namely being an archipelago and Australia was included in the list because, similar to Hawaii, it is an isolated market. It is worth

[142] We acknowledged that California is also looking into the distribution-focused initiatives. The California PUC published a "DER Action Plan" in November 2016. Its scope includes 1) rates and tariffs, 2) distribution grid infrastructure, planning, interconnection and procurement, and 3) wholesale DER market integration and interconnection. However, California's approach focuses on specific DER integration assessments and optimization of utility operations and planning, while New York called for an overhaul of the utility business model. Source: ScottMadden. *California and New York DER Demonstration Projects*. May 2017.

noting that IESO (Ontario) and AESO (Alberta) has transitioned its ratemaking method to PBR as well in the past several years.

Moreover, Colorado and Utah were selected as markets that have lighter regulation for co-ops but use a different approach from Alaska. Figure 16 summarizes basic information of each market under ISO model, PBR model, and lighter regulation for co-ops.

5.1 Markets that have established ISOs

As mentioned in Task 2.1.1, in the US and Canada, there are nine ISOs found in the late 1990s. Three of them, including ERCOT (1996),[143] PJM (1996),[144] and ISO New England ("ISO-NE") (1997),[145] were established more than 20 years ago. Six of them, including California ISO ("CAISO") (1998),[146] Independent Electricity System Operator ("IESO") (1998),[147] NYISO (1999),[148] Midcontinent ISO ("MISO") (2001),[149] Alberta Electric System Operator ("AESO") (2003),[150] and Southwest Power Pool (("SPP") (2004),[151] were established in the last 20 years (Figure 17). Since MISO and SPP are multi-state ISOs, and NYISO was discussed in Section 4.2, this section will focus on CAISO, IESO, and AESO as they are single-state ISOs with aggressive renewable policies and initiatives especially in CAISO and IESO (like Hawaii).

CAISO, IESO, and AESO are governed by a board of directors and support their operations through charges to market participants. The key tasks of these ISOs are almost the same, including providing open and competitive access to the transmission grids, planning resource adequacy, as well as managing market operations, etc. All of them have energy market and

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[143] ERCOT. *History*. Website. <http://www.ercot.com/about/profile/history>. Access Date: April 24, 2018.

[144] FERC. *PJM market*. Website. <https://www.ferc.gov/market-oversight/mkt-electric/pjm.asp>. Access Date: April 24, 2018.

[145] FERC. *ISO-NE – History*. Website. <https://www.iso-ne.com/about/what-we-do/history/>. Access Date: April 24, 2018.

[146] FERC. *CAISO market*. Website. <https://www.ferc.gov/market-oversight/mkt-electric/california.asp>. Access Date: April 24, 2018.

[147] IESO. *Corporate-IESO*. Website. <http://www.ieso.ca/en/corporate-ieso>. Access Date: April 24, 2018.

[148] FERC. *New York market*. Website. <https://www.ferc.gov/market-oversight/mkt-electric/new-york.asp>. Access Date: April 24, 2018.

[149] FERC. *Midwest*. Website. <https://www.ferc.gov/market-oversight/mkt-electric/midwest.asp>. Access Date: April 24, 2018.

[150] Province of Alberta. *Electric Utilities Act (Statutes of Alberta, 2003, Chapter E-5.1)*. Website. <http://www.qp.alberta.ca/documents/Acts/E05P1.pdf>. Access Date: April 24, 2018.

[151] FERC. SPP. Website. <https://www.ferc.gov/market-oversight/mkt-electric/spp.asp>. Access Date: April 24, 2018.

ancillary services, but only AESO has started to set up its capacity market.[152] The capacity in these ISOs ranges from 16,423 MW to 70,960, about 6 to 25 times of the total capacity in the State of Hawaii. Figure 18 summarizes the establishment, governance, and funding information for CAISO, IESO, and AESO.

Figure 17. Review of ISOs' establishment

ISOs	Year of establishment	Single-State ISO?
ERCOT	1996	Y
PJM	1996	N
ISO-NE	1997	N
CAISO	1998	Y
IESO	1998	Y
NYISO	1999	Y
MISO	2001	N
AESO	2003	Y
SPP	2004	N

Note: PJM: Pennsylvania-New Jersey-Maryland; ISO-NE: ISO New England; CAISO: California ISO; IESO: Independent Electricity System Operator (Ontario); NYISO: New York ISO; MISO: Midcontinent ISO; AESO: Alberta Electric System Operator; SPP: Southwest Power Pool

Source: FERC, ERCOT, IESO, AESO, etc.

Furthermore, all the three ISOs were established to encourage competition as part of the market restructuring process. As mentioned in California Assembly Bill 1890, the California ISO was set up to "increase reliability and provide new power producers equal opportunity and ability to deliver their supplies."[153] Similarly, IESO was formed to be in charge of maintaining a balance between electricity supply and demand when the electricity market was restructured and opened up to competition in Ontario.[154] AESO was also formed in the early days of deregulation in Alberta as roles and responsibilities of energy agencies were reviewed and realigned to support the new industry structure.[155]

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[152] California effectively has a bilateral spot market for capacity, where existing generators can sell their capacity on a month-ahead and year-ahead basis to load serving entities that must then show compliance with the California Public Utilities Commission's Resource Adequacy program.

[153] EIA. *Provisions of AB 1890*. Website. <https://www.eia.gov/electricity/policies/legislation/california/assemblybill.html>. Access Date: June 28, 2018.

[154] Legislative Assembly of Ontario. *Energy Competition Act 1998*.

[155] AESO. *Guide to understanding Alberta's electricity market*. Website. <https://www.aeso.ca/aeso/training/guide-to-understanding-albertas-electricity-market/>. June 28, 2018.

Figure 18. Summary of CAISO, IESO, and AESO

Comparison	CAISO	IESO	AESO
Establishment year	1998	1998	2003
Establishment process	• September 1996: Following the federal Energy Policy Act of 1992, CAISO was created as a nonprofit public benefit corporation with the passage of California Assembly Bill 1890 • March 1998: CAISO began serving 80% of the State or 30 million people	• 1998: IESO was established by the Electricity Act of Ontario • January 2015: IESO merged with the Ontario Power Authority	• 2003: AESO was created by the Electric Utilities Act of 2003
Report to?	FERC	Ontario Energy Board	Alberta Energy and Utilities Board ("EUB") and the Market Surveillance Administrator under EUB
Governing structure	• CAISO has 5 governors on its Board which are recommended by a 36-member Board Nominee Review Committee, and appointed by the Governor of the State of California and subject to confirmation by the Senate of the State of California • CAISO Board members serve three-year staggered terms, as required by state law	• IESO is governed by an independent board of directors (eleven) including an appointed Chief Executive Officer and a Chair by majority vote • There are two committees of the board: the Audit Committee and the Human Resources and Governance Committee	• AESO is governed by a board of directors (eight members), whose members are appointed by Alberta's Minister of Energy • The Board comprises of four standing committees, including the Audit Committee, Human Resources Committee, Governance and Nominations Committee, and the Power System Committee
Funding	CAISO charges a Grid Management Charge ("GMC") to market participants; other revenues including, but not limited to: fees paid for participation in the Western Energy Imbalance Market ("EIM"), generator interconnection studies, and for operation of the California-Oregon Intertie Path	The IESO has two key sources of revenue: (i) system fees, which are based on approved rates for each megawatt of electricity withdrawn from the IESO-controlled grid (including scheduled exports) and embedded generation; (ii) the Smart Metering Charge that is based on a rate approved by the OEB for each installed smart meter in the province	The AESO's four revenue sources are from market participants for transmission, energy market and renewables, and from owners of electric distribution systems and wires service providers for load settlement; there is no government funding for the operations of the AESO
Markets?	Energy market (day-ahead/ real-time), ancillary services, congestion revenue rights	Energy market (real-time), ancillary services	Energy market (day-ahead/ real-time), ancillary services, capacity market (transitioning)

Source: FERC, CAISO, IESO, AESO, etc.

The California, Ontario, and Alberta markets' experiences underline the feasibility of establishing an ISO in a single state/province out of FERC's jurisdiction. However, considering the unique characteristics that Hawaii has, decision-makers should, most of all, have a full grasp of what exactly the market should be, agree on specific goals (both for the short and long terms), establish the appropriate policy environment, design the market based on unmet needs and best practices, involve stakeholders, and allow for gradual transition. The following summarizes the lessons learned from the ISOs from the jurisdictions reviewed:

- **Developing clear objectives and policies**: challenges in the California market between 2000 and 2001 ("California crisis") were headline news across much of the world, entering immediately into regional market reform dialogues. This is a good example of the importance of developing a deep understanding of what the actual needs are and connecting those with the appropriate policy responses. California created an over-complicated regulatory structure, which could have been caused by unclear (or disagreements on) policy goals. The disconnect (combined with the inability to hedge) led to increased uncertainties, higher risk premiums, and roadblocks for implementation of critical decisions. The prolonged design and passage of the initial restructuring bill led to tightness in the system, discouraging a new generation of investments by utilities (eventually triggering the crisis). Delay in permitting and siting for proposed new entrants did not help the process, and this is a problem that continues to plague California even today given its complex regulatory approval process.

- **Some problems cannot be solved by creating more entities**: in trying to put in renewable policies, both Ontario and CA seem to have developed lots of power related state organizations, which sometimes have overlapping responsibilities. While they are trying to resolve problems by creating these, it sometimes generates more bureaucratic hassle.

- **Creating competition in the generation sector**: the Alberta case presents an example where a market, which was previously dominated by a few vertically integrated utilities, moves gradually to welcome greater competition. While the concept applies to Hawaii, minimum efficient size also needs to be a consideration.

- **Changing market designs is always complex:** for instance, Alberta has been transitioning to from an energy market to a new framework that includes any energy market and a capacity market. The stakeholder engagement process was planned to take three years (2017 to 2019), and a capacity market is anticipated to be in place by 2021.[156] Designing a market for Hawaii from scratch would be even more complex and requires more time and efforts.

5.2 Markets that have set up the PBR model

As discussed in Task 2.1.1, PBR regimes exist in multiple jurisdictions throughout the world. Unlike the UK which started moving to PBR in the 1980s, Australia, the Philippines, and Malaysia transitioned to PBR in the past twenty years. However, similar to the UK, these markets have almost the same rationale for moving into PBR, i.e., to promote economic efficiency and protect the interests of electricity consumers. This rationale applies to Hawaii as well. The Hawaii PUC noted that it is interested in PBR mechanisms that result in:

- "greater cost control and reduced rate volatility;

[156] AESO. Capacity Market Transition. Website. <https://www.aeso.ca/market/capacity-market-transition/>

- efficient investment and allocation of resources regardless of classification as capital or operating expense;
- fair distribution of risks between utilities and customers; and,
- fulfillment of State policy goals."[157]

Several markets have been implementing the PBR for quite some time now. This is the case for Australia, the Philippines, and Malaysia, which is shown on Figure 19. Their PBR is also considered as a "comprehensive" form of PBR where they have the price cap or revenue cap with other components of the PBR such as earnings sharing mechanism, performance standards with rewards (and penalties for some), off-ramps, and exogenous factors.

Figure 19. Summary of PBR regimes in Australia, the Philippines, and Malaysia

	Australia	Philippines	Malaysia (TNB)
Name of regulator	Australian Energy Regulator ("AER") – (Eastern Australia and Economic Regulation Authority (Western Australia)	Energy Regulatory Commission ("ERC")	Suruhanjaya Tenaga ("ST")
No. of dist. and trans. utilities	Distribution: 13 Transmission: 8	Distribution: 20 private Transmission: 1	Distribution: 1 Transmission: 1
Term for incentive regulation	Incentive-based regulation	Performance-based regulation ("PBR")	Incentive-based regulation ("IBR")
Current PBR	Transmission: 3rd Distribution: 2nd (Under the AER)	Transmission: 3rd Distribution: 4th	Transmission and distribution: 1st
Form of PBR	• Distribution – Revenue Cap in Queensland, New South Wales, South Australia and Tasmania; Average Revenue Cap in the ACT; Weighted Average Price Caps in Victoria (will switch to Revenue Cap from January 1, 2016) • Transmission – Revenue Cap with CPI-X • Retail – Retail margins are set by the state regulator	• Transmission – Revenue cap • Distribution – Price cap	• Customer Services - Pure Price Cap • Transmission, System Operator, Single Buyer (Operational) - Revenue Cap • Single Buyer (generation) – actual costs
Year started the PBR	1997 in Victoria	Transmission: 2003 Distribution: 2004	2014
Rationale for doing PBR	To promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect: • price, quality, safety, reliability and security of supply of electricity; and • the reliability, safety and security of the national electricity system"	• To promote economic efficiency • To share the benefits of efficiency gains between consumers and utilities • To prevent abuse of monopoly power • To encourage improved service levels • To allow utilities sufficient revenue to operate efficiently and attract investment • To provide transparency and stability	To strengthen: • Economic regulatory framework • Tariff setting mechanism and principles • Incentive mechanisms to promote efficiency • Process of tariff reviews • Creation of regulatory accounts and annual review process
Approach to setting the price	Building blocks	Building blocks	Building blocks

[157] Hawaii PUC. *Instituting a Proceeding to Investigate Performance-Based Regulation*. Order No. 35411. Docket No. 2018-0088. April 18, 2018.

	Australia	Philippines	Malaysia (TNB)
Other components of PBR	• I factor – quarterly CPI index • X factor – specific for each year and utility • Capex – ex ante capex allowances • Q factor – Service target performance incentive scheme • ESM – symmetric ESM • Z factor – applies to specific events such as regulatory or tax change, disaster or terrorist event • Off-ramps – only for transmission utilities; re-opener is available for events significantly alerting the level of capex	• I factor – weighted index of the Philippine CPI • X factor – individually determined for each entity • Capex – ex ante capex allowances • Correction factor – correction for over- or under-recovery of revenues and/or taxes during the previous regulatory period • S factor – rewards or penalties should not exceed 3% of the allowed annual revenue for any regulatory year • Off ramps – increase in I factor • Flow through – cost of purchased power, transmission costs, force majeure, and tax change events	
Performance standards	The Service Target Performance Incentive Scheme has three components applied to TNSPs: • Service Component • Market Impact Component • Network Capability Component – except Directlink and Murraylink The Service Target Performance Incentive Scheme also has four components applied to DNSPs: • 'reliability of supply' component • 'quality of supply' component • 'customer service' component • 'guaranteed service level' component The AER sets the performance indicators and NSPs needed to submit annual compliance report	ERC specifies the indices of Network Performance and Service Performance Network performance measures: • System average interruption frequency index • Customer average interruption duration index • Planned system average interruption duration index • Voltage regulation • Service losses Service performance measures: • Time to process applications for Regulated Distribution Services • Time to connect premises to the Regulated Distribution System after compliance with all government and Regulated Entity requirement • Percentage of calls answered at the call center within a predetermined time Each indicator will be weighted when calculating the performance factor	TNB business entities recommend a list of 3 operational performance indicators and demonstrate that they comply with the criteria: • Relates closely to the business activities of the TNB business entities; • Highly valued by electricity customers; • Can be objectively measured; and • Can be independently audited Take into consideration performance standards set in other international jurisdictions, which have implemented incentive-based regulatory frameworks for electricity industries

Note: TNB is Tenaga Nasional Berhad, the only electric utility in Peninsular Malaysia.
Source: LEI, AER, ERC, ST Malaysia, etc.

Hawaii can learn from these jurisdictions that have extensive/ongoing PBR regimes from many perspectives:

- **General guidelines are needed for the PBR transition:** guidelines from the markets provide a brief background on the purpose of the PBR transition and how they relate to the energy regulations and the powers of the Commission. In Hawaii, the Ratepayer Protection Act 005 and the PUC Order 35411 provided some guidelines on the goals of the PBR.

- **Targets should be balanced:** targets set for efficiency and productivity need to be balanced against the financial viability of the utility and consideration of costs that are within management's control.

- **The relationship of capital expenditure ("capex") and operating expenditure ("opex") should be clarified:**

    - recognition of national policies and how these policies impact the utilities;

    - clear efficiency scheme; and

    - encouragement of innovative projects.

- **Risk management mechanisms are needed:** in successful PBR regimes, the regulator has provided appropriate tools to manage risks to customers and the utility for factors that are beyond the utility's control. The three jurisdictions have exogenous factors, offramps, and reopeners to mitigate the risks.

- **Utilities need an appeal process:** jurisdictions allow for an appeal process to provide the utilities the opportunity to review the Regulator's decision.

- **Finally, a PBR design needs to be customized to the specific environment and circumstances of the regulated utility**:

    - A regulatory framework from another jurisdiction or utility may not work as well in another utility because of numerous factors such as inherent economic and market differences, business practices, policy-driven obligations, and regulatory or institutional requirements.

    - The regulator needs to take the utility's unique characteristics, type of customers served, and underlying economy into account.

5.3 Co-ops that are under lighter regulation from PUC

There are over 834 distribution and 63 generation and transmission ("G&T") cooperatives in 47 states.[158] PUCs regulate their tariffs in only 16 of the 47 states that have electric cooperatives.[159] However, it is worth noting that KIUC is different from most of the co-ops, i.e., distribution cooperatives, as KIUC is a vertically-integrated utility that owns generation, transmission, and distribution. Thus, the Project Team reviewed states that have co-ops that own generation, and found that Alaska, Utah, and Colorado are the three states that have most co-ps that own

[158] NRECA. *2017 Fact Sheet*. January 31, 2017.

[159] NRECA International. *Guides for Electric Cooperative Development and Rural Electrification*. Page 8.

generation.[160] Figure 20 summarizes different regulation for G&T co-ops in Alaska, Colorado, and Utah.

Figure 20. Summary of lighter regulation for G&T co-ops in Alaska, Colorado, and Utah

Comparison	Alaska	Colorado	Utah
What is "lighter" for G&T coops	deregulation or reregulation if voted by the members	N/A*	G&T coops are exempted from regulation on "rates, fares, tolls, or charges"
What remains the same for G&T coops	certification and transfer of certification	regulated as public utilities by the PUC, under the same authority as are investor-owned utilities	any other regulation (except rates), including, but not limited to, investigations, safety, mergers and consolidations, etc.

*Note: In Colorado, distribution cooperatives could be exempted from public utilities law by a vote of their members, but G&T co-ops are explicitly not covered by this Article (See C.R.S. §§ 40-9.5-102; 40-1-103(2)(a) & (b)(I))

As analyzed above, Alaska Statutes allows cooperatives to be exempt from the regulation by the Regulatory Commission of Alaska. Unlike Alaska, Colorado Legislation allows distribution co-ops to be exempt from PUC regulation, but this does not apply to G&T electric cooperatives.[161] The Utah Public Service Commission has jurisdiction over cooperative owned public utilities,[162] but the Utah Legislation states that the PUC does not have rate regulation authority over wholesale electrical co-op, i.e., Deseret Generation & Transmission Cooperative.[163]

However, unlike Alaska, Utah Legislation only allows "lighter" regulation rather than "deregulation" for G&T co-op. As stated in Utah Legislation 54.4.1.1, the Utah Public Service Commission "*does not have the authority to regulate, fix, or otherwise approve or establish the rates, fares, tolls, or charges of*" a G&T cooperative.[164]

Nevertheless, G&T co-ops are "*not exempt from other areas of regulation including, but not limited to, regulation having an indirect effect on rates, fares, tolls, or charges but which does not constitute an*

[160] Data from S&P Global "Energy Companies by State" Screening. In terms of cooperatives with generation, Alaska has 12, Utah has 7, and Colorado has 7.

[161] Colorado Revised Statues. 40-9.5-102.

[162] Utah Department of Commerce. Division of Public Utilities. About the Division of Public Utilities. <https://publicutilities.utah.gov/about.html>.

[163] Utah Code. 54-4-1.1. <https://le.utah.gov/xcode/Title54/Chapter4/54-4-S1.1.html>

[164] Utah Legislature. 54.4.1.1 Wholesale electrical cooperative exempt from rate regulation – requirements for rate increase. < https://le.utah.gov/xcode/Title54/Chapter4/54-4-S1.1.html?v=C54-4-S1.1_1800010118000101>

approval or establishment of them."[165] Moreover, the G&T co-op must hold a public meeting for all its customers and members prior to the implementation of any rate increase, and any schedule of new rates or other change that results in new rates must be approved by the board of directors of the G&T co-op.[166]

Based on the publicly available data, the Project Team reviewed the G&T co-ops that moved to be under lighter regulation in these jurisdictions in the past 20 years and decided to use Kodiak Electric Association in Alaska as a case for further analysis.

Kodiak Electric Association ("KEA") is a rural electric cooperative that owns generation and distribution in Kodiak, Alaska. KEA serves approximately 4,000 members,[167] about 16% of the 24,745 members served by KIUC.[168] In November 2004, KEA conducted a deregulation election and received 1,178 returned ballots (about 29% of its total members). Since the 1,178 ballots were more than 15% of its members (required for a valid election), the staff of Regulatory Commission of Alaska proceeded and tabulated the ballots. As a result, KEA was exempt from PUC's regulation including an investigation of rates, rules, regulations, practices, services, and facilities, under Alaska Statues 42.05 *Alaska Public Regulatory Act*.[169] However, the certification and transfer of certificate are still subject to the approval of the RCA.[170] And correspondingly, instead of annual regulatory cost charge, as an exempt utility, KEA shall pay the actual cost of services provided to it by the RCA.[171] Furthermore, deregulated cooperatives may elect to terminate its exemption (i.e., start reregulation by the RCA) in the same election procedure.[172]

Several lessons learned might be helpful for Hawaii:

- **There is no single format of "lighter" regulation:** as illustrated above, different states have a different approach in regulating co-ops, especially co-ops with generation. G&T co-ops are under varying levels of regulation in Alaska, Colorado, and Utah.

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[165] Ibid.

[166] Ibid.

[167] Kodiak Electric Association. *Distribution*. Access Date: July 5, 2018. Web. <http://www.kodiakelectric.com/distribution.html>

[168] KIUC. *About Us*. Access Date: July 5, 2018. Web. <http://website.kiuc.co-op/content/about-us>

[169] Alaska Statues. 42.05.141 General Powers and Duties of the Commission. <http://www.touchngo.com/lglcntr/akstats/Statutes/Title42/Chapter05/Section141.htm>

[170] Alaska Statues. 42.05.711 Exemptions. (h) <http://www.touchngo.com/lglcntr/akstats/Statutes/Title42/Chapter05/Section711.htm>

[171] Alaska Statues. 42.05.254 Public Utility Regulatory Cost Charge. (a) <http://www.touchngo.com/lglcntr/akstats/Statutes/Title42/Chapter05/Section254.htm>

[172] Alaska Statues. 42.05.712 Deregulation Ballot. (h) <http://www.touchngo.com/lglcntr/akstats/Statutes/Title42/Chapter05/Section712.htm>

- **The design of lighter regulation for KIUC should be suitable to KIUC's unique characteristics**: different from distribution co-ops or G&T co-ops, KIUC is a vertically-integrated utility. Regulation over a vertically-integrated co-op, like KIUC, might differ from regulation over distribution co-ops and/or G&T co-ops. Further analysis is required to determine where and when greater or lighter regulation is needed for a vertically-integrated co-op like KIUC.

6 Appendix A: Scope of work to which this deliverable responds

Task 2.2.2 Assessment of current markets under each regulatory model, including a case study, analysis, and conclusions.

CONTRACTOR shall provide examples of current markets under each regulatory model and provide examples of markets that have changed regulatory model in the last 20 years. CONTRACTOR shall provide the outgoing and incoming regulatory and ownership models: 1) number of utilities serving the market; 2) number of customers served; 3) capacity; 4) annual sales; 5) average fixed and variable retail rates; and 6) utility credit rating of each utility in the market before regulatory change and each year after regulatory change as data is available.

DELIVERABLE FOR TASK 2.2.2. CONTRACTOR shall provide its conclusions and all work related to current markets under each regulatory model including a more detailed assessment of the regulatory models and a case study of one jurisdiction under each of the regulatory models that is currently under that regulatory model. CONTRACTOR shall include an analysis of six to ten jurisdictions that have changed regulatory models, focusing on identifying at least one example for each of this study's regulatory models. The CONTRACTOR shall provide a summary of analysis and conclusions of this research in MS Word and PowerPoint. CONTRACTOR shall submit deliverable for TASK 2.2.2 to the STATE for approval.

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Preliminary and High-Level Assessment of the Regulatory Models' Technical, Financial, and Legal Feasibility

A working paper prepared by London Economics International LLC for the State of Hawaii with support from Yamamoto Caliboso for the State of Hawaii

August 23, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group and Yamamoto Caliboso, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This document, responding to Task 2.2.3 in the project scope of work, is one of several working papers developed to support the study. Several regulatory models were reviewed, (1) status quo with increased oversight [the Hawaii Electricity Reliability Administrator ("HERA") model], (2) independent grid operator ("IGO") model, (3) distribution-focused regulatory model [the Distributed System Platform Provider ("DSPP") model], (4) three performance-based regulation ("PBR") models, and (5) Lighter Regulation for cooperatives model (the "Lighter Regulation" model). The current regulatory model, the status quo, is assessed in Task 2.1.2 (High-level and general assessment of the existing regulatory model in place in Hawaii).

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List of acronyms

ADMS	Advanced Distribution Management System
BNMC	Buffalo Niagara Medical Campus Inc.
BPS	Bulk power system
Capex	Capital expenditure
Co-op	Cooperative
COS	Cost-of-service
DBEDT	Department of Business Economic Development and Tourism
DER	Distributed energy resource
DERMS	Distributed Energy Resource Management Systems
DSIP	Distributed System Implementation Plan
DSP	Distributed System Platform
DSPP	Distributed System Platform Provider
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
ESM	Earnings sharing mechanism
FERC	Federal Energy Regulatory Commission
HECO	Hawaiian Electric Company, Inc.
HEI	Hawaiian Electric Industries
HELCO	Hawaiian Electric Light Company
HERA	Hawaii Electricity Reliability Administrator
HRS	Hawaii Revised Statute
IGO	Independent Grid Operator
IOU	Investor-owned utility
IPP	Independent power producer
ISO	Independent System Operator
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company
NARUC	National Association of Regulatory Utility Commissioners

NERC	North American Electric Reliability Corporation
Ofgem	Office of Gas and Electricity Markets
P2P	Peer-to-peer
PBR	Performance-based regulation
PIM	Performance incentive mechanism
POC	Points of control
PPA	Power purchase agreement
PSR	Platform Service Revenue
PUC	Public Utilities Commission
PUCT	Public Utilities Commission of Texas
PV	Photovoltaic
RE	Reliability Entity
REV	Reforming the Energy Vision
RTO	Regional transmission organization
RUS	Rural Utilities Service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SB	Senate Bill
UK	United Kingdom

1 Executive summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership and regulatory models, which can help facilitate the achievement of the State's energy goals. This working paper, which responds to Task 2.2.3 in the project scope of work, provides a high-level assessment of the technical, financial, and legal feasibility of various regulatory models.

Several utility regulatory structures were reviewed based on the scope of work provided and our evaluation of various additional potential arrangements. These models include (i) status quo with increased oversight [i.e., with Hawaii Electric Reliability Administrator ("HERA")], (ii) independent grid operator ("IGO") model, (iii) distribution-focused regulatory model (more specifically the distribution system platform provider or "DSPP" model), and (iv) performance-based regulation ("PBR"). A detailed assessment of the fifth and current regulatory model, the status quo, is provided in Task 2.1.2 (High-level and general evaluation of the existing regulatory model in place in Hawaii). Following this assessment, Task 2.2.6 (Recommendation for the three most beneficial models) will narrow down the evaluation of regulatory models to three recommended models through a ranking and weighting process.

Ultimately, the feasibility analysis (as presented in this paper) aims to assess the performance of the regulatory models with regards to the State's key criteria, namely the abilities of the models in achieving State energy goals, maximizing consumer cost savings, enabling a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs, and eliminating or reducing conflicts of interest in energy resource planning, delivery, and regulation. The high-level assessment will aid in understanding the long-term operational and financial costs and benefits of utility regulatory models that can serve each county of the State. It will also be useful in identifying processes to be undertaken in order to establish regulatory models successfully in the context of Hawaii's existing regulatory model.

In that regard, some of the key findings of the technical feasibility include:

- All the models should be able to comply with service, quality and reliability standards, with the presence of an independent monitor or the commission itself performing the role of enforcing standards.

- Three of the assessed models—HERA, IGO, and distribution models—entail the creation of new entities needed for their implementation. The Hawaii Public Utilities Commission ("PUC", or "the Commission") will play a pivotal role in the definition of mandate and scope during the creation of these new entities. These regulatory models—unlike the other models such as PBR and the status quo—face a significant implementation risk on how to design and create a new entity successfully.

- The models vary in their ability to achive the State's energy goals. Our high-level analysis suggests that the PBR model could be designed to incentivize achievement of the State goals directly while the IGO model may maximize efficiency gains at the expense of the State's broader policy goals. The HERA model is limited by the scope and mandate that

remains at the discretion of the Commission while the DSPP model is promising but has a high level of implementation risks.

Below are some of the key findings on financial feasibility:

- For most of the models, the role of the utility in generation, transmission, and distribution will largely be unchanged, assuming that regulation remains unchanged. The IGO and the DSPP models—which require regulatory changes to allow for greater competition in generation—are exceptions to this issue.

- The financial requirements for the implementation of each model vary broadly across each model, with the IGO model likely to require the most significant implementation costs given the need for IGOs in each island. In comparison, the implementation costs for the PBR model will be less than that of the IGO because it does not require the creation of new entities; nonetheless, the PBR model would involve a far more intensive process for the PUC. The distribution-focused model could also require significant costs with the technical upgrades needed to facilitate the model. The HERA model has a legislated funding surcharge, but the scale of its implementation cost would depend on the ultimate scope of the entity's mandate. Should it be tasked with increased monitoring, the creation of new Hawaii-specific standards, and provision of standards training, costs would increase accordingly.

- The financial impact of each model on ratepayers also varies across each model, with the implementation costs driving the costs to customers. The efficiency gains in the market-based regulatory models (i.e., the IGO and DSPP models) could be offset by the implementation costs, market design, and commitment to transition by the Commission.

Below are some of the key findings on legal feasibility:

- A number of the models, particularly IGO and DSPP models, require relevant legal framework for successful implementation. Similarly, although a framework exists for the HERA and PBR models, an investigative docket or rulemaking proceeding is still likely required. In the case of the latter, a PBR proceeding is currently underway.

- The implementation of the proposed models requires addressing legal issues—including the status of existing power purchase agreements, fuel purchasing contracts, and the need to assure a reasonable return for prudently-made investments by utilities during previous regulatory regimes.

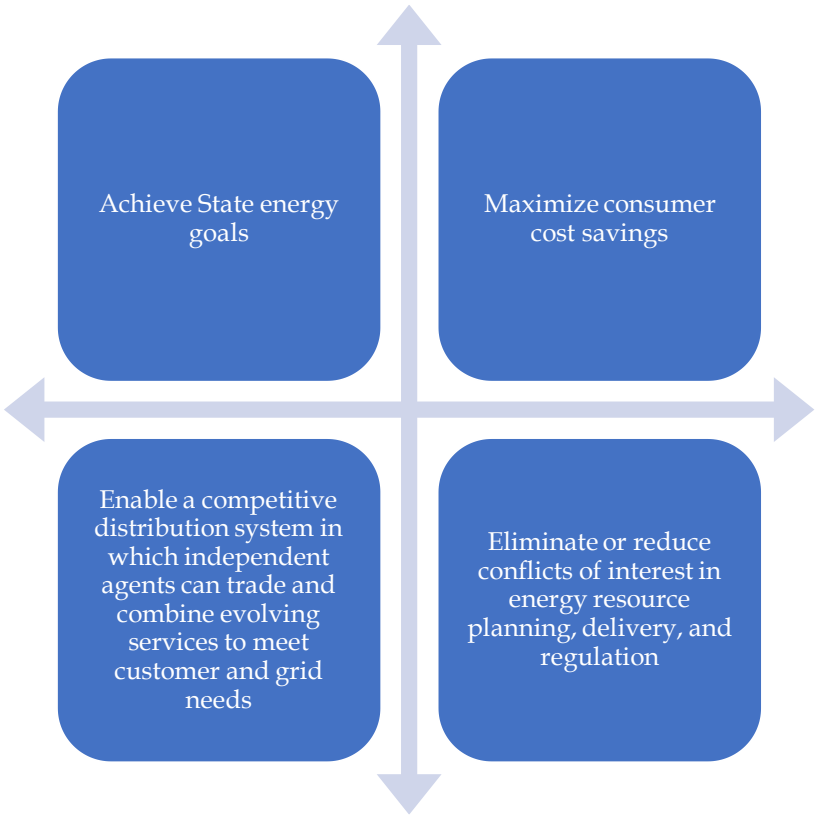
2 Introduction and scope

2.1 Project description

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the State Legislature to commission a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models, which can support the state in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement[1], was contracted to perform this study.[2]

The project aims to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[3] (Figure 1).

Figure 1. State's Key Criteria in Evaluating the Models



Source: Scope of Services under Contract No. 65595

[1] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[2] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[3] House Bill No. 1700 Relating to the State Budget.

The study will help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models that can best serve each county of the state. Moreover, it will also aid in identifying the process that must be followed in forming such ownership and regulatory models as well as determining whether such models would create synergies. Such synergies are beneficial in terms of increasing local control over energy sources serving each county, ability to diversify energy resources, economic development, reducing greenhouse gas emissions, increasing system reliability and power quality, and lowering costs to all consumers.[4]

2.2 Role of this deliverable relative to others in the project

This deliverable fulfills Task 2.2.3 in the project scope of work. It provides a broad analysis of the technical, financial, and legal feasibility of regulatory models proposed in previous tasks. It assesses these feasibilities in the context of Hawaii's existing regulatory model, providing the Project Team's assessment of the risks associated with their implementation.

Various aspects of the regulatory models will be further explored in subsequent deliverables. These include:

- summary analysis and conclusions related to estimating stranded costs for each regulatory model (Task 2.2.4);
- solicitation of public input on the results of Task 2.1.1 through 2.2.4 (Task 2.2.5) from each island currently served by an electric utility;
- identification of and recommendation for the three most beneficial regulatory models for further consideration (Task 2.2.6);
- identification of steps, costs, and projected timelines, if there will be a change from the current regulatory model to the recommended regulatory models (Task 2.3.1);
- analysis of Hawaii law and history to help determine the required regulatory and legislative changes in the implementation of the recommended regulatory models (Task 2.3.2);
- identification and assessment of the impact of financial and operational risks for different stakeholders under each regulatory model (Task 2.3.3);
- assessment of how each recommended model impacts State agencies' staffing and stakeholders (Task 2.3.4);
- estimated potential of each model in increasing distributed energy resources (Task 2.4.1); and,
- evaluation of revenue requirements, system average retail rates, risks to utility valuations, and funding mechanisms of each regulatory model (Task 2.5).

[4] Hawaii Contract No. 65595. Scope of Services.

2.3 Future refinements

This deliverable is the Project Team's assessment of the feasibility of each of the proposed regulatory models, which may be subject to further improvement or change as the project moves forward and receives inputs from the stakeholder groups and results of the quantitative analysis and case studies become available.

The feasibility analysis is a high-level one—supplemented by case studies (included in Task 2.2.2)—allowing us to highlight the essential features of the different regulatory models and key issues and lessons from other jurisdictions or utilities.

The project will provide various opportunities for stakeholder inputs and participation. LEI will engage a wide range of stakeholders and perspectives across all islands through a series of facilitated dialogues, one-on-one meetings, and workshops.[5]

[5] A series of community meetings across the state was held in June 2018 in Hawaii. The workshops provided opportunities for the attendees as well as online participants to hear from key stakeholders in the energy policy discussion and provide inputs to the study through the small group discussions.

3 Key concepts

The Project Team conducted a high-level feasibility analysis of the technical, financial, and legal aspects of each regulatory model discussed in previous work papers. Feasibility, in the context of this study, attempts to determine the most effective, efficient, and viable regulatory model with which the State of Hawaii can achieve its energy goals.

"Inclinations" of the PUC on the Future of Hawaii's Electric Utilities

The PUC outlined key inclinations on the future of Hawaii's electric utilities to guide utility business strategy, energy resource planning, and project review. These guiding principles include:

- **Creating a 21st Century Generation System:** Hawaii currently relies heavily on oil-fired electricity generation, which is expensive compared to modern, clean energy technologies. Utilities should move urgently to capitalize on cost-saving opportunities by modernizing electricity generation with clean and efficient resources on all islands.

- **Creating Modern Transmission and Distribution Grids:** future electric grids must be designed as advanced networks that integrate greater quantities of customer-sited distributed energy resources ("DERs") and offer customers increased opportunities to manage their energy usage.

- **Policy and Regulatory Reforms to Achieve Hawaii's Clean Energy Future:** the PUC noted that the HECO Companies[6] "*may not currently have the appropriate financial incentives*" to achieve Hawaii's policy goals. In particular, "*inherent financial conflicts*" related to utility ownership of generation and related compensation frameworks result in a "*lack [of] correct incentives to control power supply costs, aggressively pursue long-term contracts with IPPs for new renewable energy projects, and expeditiously retire old, inefficient generation units*." Utilities will need to transform their business models, such as by focusing on "*energy delivery*" and related grid modernization functions, rather than generation. Similarly, the PUC stated that it might need to transform regulatory frameworks, such as by setting up new financial incentive mechanisms, unbundling ancillary services from electricity pricing, and forbidding the ownership of new generation by utilities. These new business and regulatory models will enable utilities to meet rapidly changing customer, technical, and economic requirements.

Source: Hawaii Public Utilities Commission, "*Exhibit A: Commission's Inclinations on the Future of Hawaii's Electric Utilities*," Docket No. 2012-0036, Decision and Order No. 32052, filed on April 28, 2 014, ("Order No. 32052"), available at https://puc.Hawaii.gov/wp-content/uploads/2014/04/Commissions-Inclinations.pdf

[6] The term "HECO Companies" refers specifically to Hawaiian Electric Company ("HECO"), Maui Electric Company ("MECO"), and Hawaiian Electric Light Company ("HELCO"). The analysis within this report is not intended to apply to the American Savings Bank, which is a subsidiary of HEI. In some cases, the term "HEI" (for Hawaiian Electric Industries) is used to refer to the ownership entity of the HECO Companies.

In performing the high-level feasibility analysis, the Project Team drew heavily from available literature and guidelines of the PUC. More specifically, we looked at various statutes, PUC Decisions, and Orders. These include:

- The standards for electricity service as outlined in General Order No. 7 by the PUC;
- The performance metrics for electric utilities as outlined by the PUC;
- The responsibilities of the PUC as specified under Hawaii Revised Statute ("HRS"), particularly Title 15 "Transportation and Utilities," Chapter 269 "Public Utilities Commission;" and
- The "Inclinations" of the PUC for the clean energy vision of Hawaii as outlined in textbox.

3.1 Technical feasibility

Technical feasibility evaluates whether the regulatory model in question enhances or diminishes the utility's ability to carry out its roles and responsibilities. The PUC has identified the functions of an electric utility through various regulations and laws. These include provision of adequate and reliable energy supply, avoidance of interruption of services, compliance with standards set by the PUC, and maintainance of service quality (Box 2).

Moreover, the State has set explicit energy goals, some of which are listed below:

- to source 100% of electricity from renewable energy by 2045[7];
- to have a diversified energy portfolio that makes the best use of land and resources;
- to have integrated and modernized grids;
- to balance technical, economic, environmental, and cultural considerations;
- to leverage Hawaii's position as an innovation test bed; and
- to have an efficient marketplace that is beneficial to producers and consumers.[8]

Recognizing the said goals, this technical feasibility analysis considers whether the new regulatory model could help ensure that electric utilities can perform their responsibilities as directed by the PUC.

Major Responsibilities of an Electric Utility (non-exhaustive list)

PUC General Order No. 7 outlines the key standards for Electric Utility Service in the State of Hawaii. Moreover, the PUC has further outlined performance metrics that should accompany

[7] HRS § 269-92.

[8] Hawaii State Energy Office, Hawaii Department of Business, Economic Development, and Tourism, "Energy Policy Directives," March 2017, available at https://energy.Hawai'i.gov/wp-content/uploads/2011/08/EnergyPolicy_1pgr_rev-Mar2017.pdf.

such standards. The following summarizes some of the key responsibilities of an electric utility as well as the metrics for those responsibilities:

1. Provide an adequate and reliable electricity supply

Rule 5.3.a of General Order No. 7 states that the generation capacity of the utility's plants, supplemented by electric power regularly available from other sources, must be sufficiently large to meet all reasonably expectable demands for service and provide a reasonable reserve for emergencies. The performance metrics for this include Equivalent Availability Factor, Equivalent Forced Outage Rate-Demand, Equivalent Forced Outage Factor, and ratio of IPP Energy/Net to System Energy. These are performance indices, which are broadly used for availability of generation resources that provide power.

2. Avoid interruptions of service

Rule 7.5 of General Order No. 7 establishes that each utility shall make reasonable efforts to avoid interruptions of service but when interruption occurs, service shall be re-established within the shortest time practicable, consistent with safety. The performance metrics for this include the System Average Interruption Duration Index ("SAIDI"), which measures the average interruption time for all customers served during a given period of time, and the System Average Interruption Frequency Index ("SAIFI") which measures the average number of interruptions experienced by all customers served during a given time period.

3. Meet quality of service standards

The Hawaii PUC requires regulated utilities to continually achieve high quality of service standards. Quality of service includes aspects of customer service and technical services, involving both interactions and engagements between customers and HECO Companies. The performance metrics for this include the percentage of customer calls answered within 30 seconds and consumer transaction survey results.

Sources: Hawaii Public Utilities Commission, "*Hawaii General Order No. 7*," available at: https://puc.Hawaii.gov/wp-content/uploads/2013/04/General-Order-7.pdf; Hawaii Public Utilities Commission, "*Approving the Release of Performance Metrics, Directing that the Approved Performance Metrics be Posted to the Websites, and Directing the Parties to Develop Additional Performance Metrics*," Order No. 32701, available at: http://dms.puc.Hawaii.gov/dms/DocumentViewer?pid=A1001001A15C12A92431G90153

3.2 Financial feasibility

Financial feasibility evaluates the reasonableness of the proposed regulatory model in financial and economic terms. Since "financial feasibility" can encompass many factors, this analysis is limited to the financial viability of the regulatory model and the financial impact on the ratepayers. The following are key questions that are considered in assessing the financial feasibility:

- How does the proposed regulatory model affect the financial viability of power sector participants?

- Are the utilities able to earn a fair rate of return with the change of the regulatory model?
- Are ratepayers likely to be better or worse off as a result of the implementation of the regulatory model?

3.3 Legal feasibility

Legal feasibility assesses whether the transition to another regulatory model is legally possible given the laws, statutes, and regulations currently in effect. This analysis considers legal requirements—whether new ones or revisions of existing ones—of the regulatory model under consideration. Policy interventions will likely vary depending on the requirements of the chosen regulatory model. Our analysis seeks to identify any significant legal challenges to the transition to another regulatory model. In doing so, our analysis draws heavily upon the regulatory frameworks established by the State Legislature and the PUC.

The key questions that inform the legal feasibility are listed below:

- Is there an existing legal framework for this regulatory model?
- Is the PUC authorized under the current legal and regulatory framework to implement the regulatory model under consideration?
- What statutory changes or laws, if any, are required to be enacted by the State Legislature to implement this regulatory model?
- What administrative actions must be undertaken by the PUC to implement this regulatory model?
- Are there any additional legal issues that could substantially affect the viability of this regulatory model?

4 Status quo with increased oversight

As discussed in previous working papers, the utility would continue to operate the transmission and distribution network under the status quo with increased oversight model. As in the status quo model, the utility would continue to be responsible for systems operations, system planning, and dispatch. Nonetheless, in this case, increased oversight would be leveraged through HERA, established by the Hawaii State Legislation (Act 166) in 2012.

While Hawaii State Legislature passed legislation allowing for the establishment of a HERA in 2012, no action has been taken yet toward its establishment. In 2012, the Hawaii PUC was authorized to "*contract for the services of a Hawaii electricity reliability administrator to support the commission in carrying out [critical functions] throughout the State.*"[9] As such, the Hawaii PUC may contract with a person, business, or organization (except a public utility) for the performance of HERA's functions.[10]

4.1 Technical feasibility

4.1.1 Requirements for establishment

The formation of an entity such as HERA is a voluntary process that must be initiated by the Commission. As such, the PUC would be required to commence stakeholdering, which can help decide upon various facets of HERA such as the entity's mission, responsibilities, budget, and staffing requirements. Once the PUC has gathered inputs from the stakeholders, the Commission staff would issue a draft proposal reflecting the purpose and characteristics of such an entity. The proposal would serve as a foundation for further stakeholdering, from which the Hawaii PUC would be able to establish final qualification requirements, for example, the issuance of the rule or order creating HERA.

The Hawaii PUC would then select the HERA via a competitive procurement mechanism. The contract to act as HERA could be awarded through a competitive bid, scored request for proposal, or sole source procurement in certain situations, as per HRS 103D.[11] Based on the budget established via the final PUC order, the Commission would establish an electricity reliability surcharge, which would be collected to support the operations of the newly established HERA.

[9] Hawaii House Bill No. 2525 (2012).

[10] HRS 269-147.

[11] Mayor's Office of Economic Development, Energy Commissioner, DKK, and SES. *Comparing the Structure and Function of a HERA to an ISO: Report and Task Analysis for use by the County of Maui.* August 25, 2017. Page 63.

Furthermore, the Hawaii PUC would need to hire an Executive Director for HERA, who would then appoint the staff of the organization. Staff members would be required to have appropriate skills and levels of independence, which can enable them to develop and review reliability standards and interconnection requirements. While the HECO Companies' staff members would serve as the obvious choice, their hiring for the newly established HERA would raise some red flags. As such, the PUC would also need to create rules surrounding conflict of interest. More specifically, the PUC would need to study rules that ISOs or PUCs implement regarding hiring from regulated entities.

Once established, HERA would review matters pertaining to reliability and interconnection and thereby report on its operational and financial status to the Hawaii PUC on an annual basis.[12] Textbox gives more details on the role of HERA.

The Role of HERA

The entity acting as HERA would be required, under existing statute, to meet certain requirements such as (1) satisfying any qualifications established by the PUC by rule or order; (2) maintaining reasonable and necessary staffing of individuals who have skills and expertise to offer recommendations on the development of reliability standards and interconnection requirements, and appropriate level of independence to fairly and impartially review matters concerning interconnection to the Hawaii electric system.[1] HERA would be funded by funds collected through the Hawaii electricity reliability surcharge and it will be required to report to the PUC annually on the status of its operations, financial position, and projected operation budget for the following fiscal year.

Sources: HRS § 269-148; HRS § 269-149 (a) (b).

As discussed in Task 2.1.1, an alternative to HERA is the "Light" HERA, which could be designed as an ombudsman, an appeals body focused on hosting capacity and interconnection. The technical requirements and processes in the establishment of Light HERA would be the same as the "regular" HERA; the difference would largely be on responsibilities and tasks.

4.1.2 Impact on the roles and responsibilities of the Commission

When forming this new entity, the Hawaii PUC will seek to define HERA's mandate because the definition provided by the legislation offers a broad scope for its functions, i.e., to ensure necessary electric system reliability and grid access oversight functions. Currently, the PUC is responsible for several regulatory functions—including monitoring reliability and service quality—in the Hawaii power sector. In this role, the PUC is responsible in ensuring that the Hawaii electric system complies with all adopted reliability standards including those for interconnection.[13] The creation of HERA would require the PUC to hand over at least some of these responsibilities to the new entity as well as create new roles for the functions it would be required to perform. Insofar as the role of HERA requires greater visibility of the power system

[12] Ibid.

[13] HRS Chapter 269-144. *Compliance and enforcement.* HI Rev Stat § 269-144 (2017)

than the Commission currently does, its creation may warrant more technical and human resource capability.

4.1.3 Impact on the roles and responsibilities of utilities

Under this new regulatory model, the utilities would be required to improve and increase their reliability reporting frequency and visibility. The utilities may also be directed to provide availability and outage data, as is required by Reliability Entities ("REs") that function under the North American Electric Reliability Corporation ("NERC") jurisdiction. Typically, this is done through a portal managed by Open Access Technology International, where regional RE bodies provide coordination, analysis, user training, and support for the collection of performance data that are required for analysis of open access.[14] Utilities would require increased investment in IT and staffing in order to comply with the requirements of the PUC, such as toward increased reliability reporting frequency and visibility.

4.1.4 Compliance with reliability, adequacy, and quality of service standards

The HERA model would strengthen the utilities' compliance further with reliability and adequacy. Under the HRS Chapter 269 statutes, the PUC may "*make provisions for the Hawaii electric reliability administrator to recommend penalties and enforcement to the commission.*"[15] This provision would allow the HERA entity to be more effective in its monitoring role as it supports the Commission in the oversight of reliability and service quality standards. An empowered monitoring and compliance entity would assist the Commission in its assessment of supply adequacy in light of the State's 100% renewable energy goals. Furthermore, an independent entity constituted to focus on service quality standards is likely to take a long-term approach to ensure utilities and other suppliers maintain standards as prescribed by the Commission.

4.1.5 Ability to achieve State energy goals

HERA is expected to support the Commission in its oversight of reliability and interconnection access, through which it should enforce the State's goal of fair and transparent grid access. Among the most significant challenges for greater DER penetration is ensuring fair access to the utility grid because utilities are inclined to favor their own systems ahead of third-party access to their networks. Ensuring reliable supply, as Hawaii pursues its 100% renewable goal, is also of paramount importance as the State seeks to ensure that the increased penetration of renewable energy does not lead to a decline in the quality of supply for customers. Currently, only two reliability metrics are measured by the utilities, which have penalties. Transferring the responsibility of enforcing and monitoring reliability to HERA could ensure that reliability will not be an issue as the state tries to achieve its renewable energy goals. In addition to implementing reliability standards across the electric value chain, HERA's mandate also includes providing fair

[14] Texas Reliability Entity. *Reliability Data Systems.* Accessed at https://www.texasre.org/Pages/reliability.aspx

[15] HRS Chapter 269-144. *Compliance and enforcement.* HI Rev Stat § 269-144 (2017)

grid access to generators.[16] This could open more opportunities for more renewable generators and DER providers. Further details regarding the regulatory model's ability in facilitating the State's energy goals can be found in Task 2.2.1 (Preliminary and high-level evaluation of the regulatory models relative to the state goals).

4.2 Financial feasibility

4.2.1 Financial requirements for implementation

Under the provisions of the implementation law, "*this Act allows for the creation of a surcharge affecting users and operators of the Hawaii electric system to be collected for the purpose of maintaining system reliability.*" Furthermore, under the implementation statutes, HRS Chapter 269-146, the Commission is empowered to use the surcharge such that "*amounts collected through the Hawaii electricity reliability surcharge shall be transferred in whole or in part to any entity contracted by the commission to act as the Hawaii electricity reliability administrator provided for under this part.*"[17] Therefore, users' surcharge in the Hawaii electric system would be one of the sources of funding for the establishment and operations of HERA.

An example can be drawn from the Texas RE, which serves as the Electric Reliability Organization ("ERO") for the State of Texas. The Texas RE is responsible for monitoring reliability standards in the State and its experiences and as Texas does not lie within FERC jurisdiction, could provide lessons for the adoption of the HERA model particularly that Texas does not lie within FERC jurisdiction. Similar to HERA, the Texas RE receives its funding from a surcharge on the net load; this funding model is described further in the textbox below.

Texas Reliability Entity

Texas RE is responsible for reliability coordination in the Electricity Reliability Council of Texas ("ERCOT") ISO footprint. Within this region, which covers 75% of the Texas area and accounts for ~80% of the load in the State, Texas RE is responsible for monitoring and reporting on reliability standards in the bulk power system ("BPS").

Entities participating in the power sector in the State of Texas are regulated by the Public Utilities Commission of Texas ("PUCT"). Primarily, Texas RE is responsible for developing, monitoring, assessing, and enforcing compliance with reliability standards; developing regional standards; and evaluating and periodically reporting on the reliability and adequacy of the BPS. Texas RE also serves as the reliability monitor for the PUCT of the ERCOT region—which means that it monitors both NERC and State reliability standards.

[16] Hawaii Senate Bill 2787 (2012).

[17] HRS Chapter 269-146. *Hawaii electricity reliability surcharge; authorization; cost recovery.* HI Rev Stat § 269-146 (2017).

Texas RE is a voluntary participation organization and there is no cost to join the entity, i.e., it charges no membership fee to any qualifying entity, which is defined as any entity that is a user, owner, or operator in the ERCOT region BPS.

Texas RE obtains its funding from a number of different sources. Its primary source—known as ERO funding—is from NERC. This is derived from NERC Assessments and Penalty Sanction fees. The NERC Assessment funding is obtained from end-users, allocated based on net energy for load, and approved by the FERC. In 2016, NERC indicated that its proposed total United States net funding requirement for the ERO enterprise is equivalent to $0.0000389 per kWh, based on the aggregate net energy for load of the United States in 2015. For the year 2016, the Texas RE's total budget was approximately $11.8 billion.

Texas RE also obtains funding for state obligations, i.e., serving as reliability monitor for the PUCT. For this, it is funded through ERCOT ISO's system administration fee, which is sanctioned by the PUCT. This comprised approximately 10% of its total funding budget in 2017.

Sources: Texas RE. *2017 Annual Report;* Texas RE. *2017 Business Plan and Budget;* FERC. Docket No. RR16-6-000. *Order Accepting 2017 Business Plans and Budgets.* Issued October 20, 2016.

4.2.1 Financial impact on the Commission, utilities, and ratepayers

With the implementation of HERA, ratepayers would likely see an increase in their monthly bills. As mentioned earlier, the statutes allow the Commission to impose a surcharge to help cover the operations of HERA.

The Project Team assumes that HECO Companies' costs related to regulatory affairs would most likely increase, too, because they would need to increase reliability reporting frequency and visibility. This would mean a potential increase in investment in IT and staffing in order to comply with the requirements of HERA.

The statutes indicate that utilities would be allowed to recover "*appropriate and reasonable*" costs from ratepayers under the reliability surcharge to finance several activities related to reliability and open access. These activities including interconnection to the Hawaii electric system, relevant interconnection studies, and other analysis required in understanding the impact of necessary infrastructure and operational systems to interconnection reliability.[18]

4.3 Legal feasibility

4.3.1 Existing legal framework for the regulatory model

Under the Status Quo with HERA, Part IX, Electric Reliability, of Chapter 269, HRS ("HERA Law"), including the retention by the contract of a HERA by the PUC is assumed to be

[18] Ibid.

implemented.[19] Under the consideration that authorization has passed, the existing legal framework should not present challenges in accommodating the HERA regulatory model.

4.3.2 PUC authority under current legal and regulatory framework

As briefly discussed earlier, the Legislature authorized the PUC to adopt reliability standards and interconnection requirements,[20] so it can monitor the reliability and operation of the Hawaii electric system,[21] enforce compliance with reliability standards and interconnection requirements, including imposing reasonable penalties,[22] oversee requested interconnections with the Hawaii electric system, and make determinations in any disputes.[23] The PUC is required to "*consider the value of improving electrical generation, transmission, and distribution systems and infrastructure within the State through the use of advanced grid modernization technology in order to improve the overall reliability and operational efficiency of the Hawaii electric system*."[24] The PUC is also authorized to require a surcharge for connecting to the Hawaii electric system.[25]

Under the current statutory framework (HERA Law), the PUC is authorized to contract the performance of the PUC's functions to a third party (and serve as HERA) through a solicitation process.[26] However, a public utility is prohibited to serve as HERA and the PUC may not contract such for the performance of its functions, which include the (1) adoption of reliability standards and interconnection requirements under HRS § 269-142(a) and (b); or (2) creation of the Hawaii electric reliability surcharge.[27]

Pending contracting with a third party to act as HERA, the PUC has explained that it would continue to perform its functions under the HERA Law and effectively serve as HERA until such a body is formally established:

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[19] *See* HRS Chapter 269, Part IX (Electric Reliability); HRS § 269-147.

[20] HRS § 269-142.

[21] HRS § 269-143; HRS § 269-141 provides that, "'Hawaii electric system' means all electric elements located within the State together with all interconnections located within the State that collectively provide for the generation, transmission, distribution, storage, regulation, or physical control of electricity over a geographic area; provided that this term shall not include any electric element operating without any interconnection to any other electric element located within the State."

[22] HRS § 269-144.

[23] HRS § 269-145.

[24] HRS § 269-145.5.

[25] HRS § 269-146.

[26] HRS Chapter 269, Part IX (Electric Reliability); HRS § 269-147.

[27] HRS § 269-147.

> *"The commission recognizes that the development of HERA will require time to conduct the aforementioned HERA proceeding, to retain a potential contractor to perform HERA functions and secure a source of funding for HERA. In the interim, the commission will continue to effectively serve as HERA, until formally established. The commission's consultant for the RSWG process will continue to support the commission on reliability, interconnection, and system operational issues."*[28]

Currently, it does not appear that the PUC has already contracted the performance of its functions (to act as HERA) with any third party nor does it appear that a solicitation for bids has been issued under HRS Chapter 103D.

4.3.3 Statutory changes or laws required for implementation

There is no additional statutory change or law that needs to be enacted by the State Legislature to implement the HERA model assuming the PUC exercises its authority under the HERA Law, which provides the PUC with authority (but does not generally require it to implement the Law).

4.3.4 Administrative actions required by the PUC

To implement the HERA model (to the extent not already adopted or determined), the PUC would be required to adopt reliability standards and interconnection requirements by rule or order[29] and rules for the issuance of penalties,[30] establish procedures for interconnection with the Hawaii electric system by rule or order,[31] and set a surcharge for connecting to the Hawaii electric system by rule or order based on stakeholdering, as described in Section 4.1.1.[32] The PUC would also have to contract with a third party, which would serve as HERA as discussed above.[33]

If the PUC were to undertake any of the matters described immediately above, stakeholder input could be provided through the process that the PUC would utilize to take such actions, i.e., by "rule" or "order." If the PUC were to adopt rules, it the PUC would do so under the rulemaking process described in the Hawaii Administrative Procedures Act, HRS Chapter 91,[34] which requires public hearings.[35] If the PUC were to take an action by "order," it would do so under its

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[28] *See* Order No. 32054 Ruling on RSWG Work Product, issued in Docket 2011-0206, on April 28, 2014, at 111-113.

[29] HRS § 269-142(a).

[30] HRS § 269-144(c).

[31] HRS § 269-145(a).

[32] HRS § 269-146(a).

[33] HRS § 269-147.

[34] HRS § 269-6(a) ("Included among the general powers of the commission is the authority to adopt rules pursuant to Chapter 91 necessary for the purposes of this chapter.")

[35] HRS § 91-3.

standard docket process under HRS Chapter 269. In this procedure, stakeholders can could provide input either as intervenors/participants or by more informal public comments or additional informal stakeholder processes that could be implemented by the PUC in such dockets. In contracting with a third party that can serve as HERA, the PUC would be required to utilize a competitive procurement process under the Hawaii Public Procurement Code and HRS Chapter 103D, which does not inherently include a stakeholder or public hearing process. However, the PUC can possibly, but is not required, to seek stakeholder feedback if it chose to do so while it is undertaking the contracting of the third party under the Hawaii Public Procurement Code so long as such actions would not violate the Hawaii Public Procurement Code.

4.3.5 Additional legal issues

The current statute generally authorizes but does not mandate the performance of the PUC's functions (including contracting with a third party to serve as HERA) under the HERA Law.[36] If the HERA model is deemed to be needed, the Legislature may amend the law to mandate the performance by PUC of its functions under the HERA Law, with appropriate deadlines.

4.4 Conclusion

The feasibility of this model is dependent in part to the scope and scale of the mandate that is given to the HERA entity by the Commission. This discretion would allow the Commission to define how narrow or broad its mandate would be. This would, in turn, determine the scale of the surcharge needed to fund the new entity. However, as described above, similar entities exist on the mainland. An example is Texas RE, which illustrates the possible interactions the HERA entity would have with other power sector entities and a working framework that exists outside the jurisdiction of FERC.

Possible uncertainties include the lack of clear scope definition that lies with the Commission and questions over enforcement. Therefore, it ranks as *neutral to low risk* in terms of overall feasibility. A summary of the feasibility criteria considered is given in Figure 2.

[36] HRS § 269-147.

Figure 2. HERA Model: Feasibility Criteria Summary

Criteria	Categorization	Various Considerations
Technical Feasibility	Implications for role and responsibilities	(+/-) Depends on scope of mandate of HERA
	Compliance with service standards	(+) Increased reporting frequency and visibility
	Achievement of State clean energy goals	(+) Promote DER integration and penetration
Financial Feasibility	Implementation requirements	(+) Surcharge already defined in legislation
	Impact on ratepayers	(+) Costs are expected to be borne by ratepayers
	Impact on utilities	(+) Increased reporting requirements and facilitation of open access requests
Legal Feasibility	Existence of supporting legal framework	(+) No additional statutory changes or laws needed
	Governance requirements	(+) No additional statutory changes or laws needed
	Additional legal factors	(-) Existing statute does not mandate PUC performance

Source: LEI analysis

5 Independent grid operator

An independent system operator ("ISO") or a regional transmission organization ("RTO") is an independent, membership-based, nonprofit organization that ensures reliability and uses bid-based markets to determine economic dispatch for wholesale electric power.[37] The concept of an ISO came from Order Nos. 888/889, followed by the introduction of the concept of an RTO in Order No. 2000 by the Federal Energy Regulatory Commission ("FERC").

As per Order No. 2000, the minimum characteristics of an RTO include independence, scope, regional configuration, operational authority, and short-term reliability.[38] FERC's minimum functions as an RTO include tariff administration and design; congestion management; parallel path flow; ancillary services; establishment of or participation in a transparent system for data access; monitoring, computing, and managing of transmission capacity; market monitoring; planning and expansion; and interregional coordination.[39]

Hawaii is not part of FERC so the scope of work of the ISO could be tailored to the needs of the state, taking its size and unique features into account. For the purpose of the Study, the Project Team assumes that the responsibilities of the ISO in Hawaii, as discussed in previous working papers, include dispatch and resource planning. Moreover, the ISO under the Hawaii context would cover both the transmission and distribution sectors, thus, will be called the independent grid operator ("IGO").

5.1 Technical feasibility

5.1.1 Requirements for establishment

While the State of Hawaii does not lie within FERC and NERC jurisdictions, an IGO can also be formed for the purposes of system planning and dispatch in each island without participating in interstate commerce. Nonetheless, the State of Texas provides an example of how a state can still achieve the objectives outlined in FERC Order 888. ERCOT is an ISO that operates the transmission system within the boundaries of the state, representing 90% of Texas load, and is only interconnected to other grids by way of DC Ties and Block Load Transfers, thereby making it an "electrical island."[40]

To establish an IGO, the Legislature would first need to enact legislation to ensure open access for wholesale electricity market participants, the functional unbundling of transmission service,

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[37] "Today in Energy." *EIA*. Website. Accessed at https://www.eia.gov/todayinenergy/detail.php?id=790. Access Date: April 19, 2018.

[38] FERC. *Regional Transmission Organizations* (Issued December 20, 1999). (Docket No. RM99-2-000; Order No. 2000), page 151.

[39] Ibid., page 323.

[40] "ERCOT Nodal 101." *ERCOT*. Training. Website. Accessed at http://www.ercot.com/services/training/course/109518. Access Date: May 19, 2018.

and the establishment of open access transmission tariffs, thereby opening doors to competitive wholesale generators and ensuring open access to the transmission system. With sufficient and appropriate legislative authority, the PUC would subsequently direct the establishment of an IGO—a non-profit third-party organization that will oversee equal access to the power grid—for each county. As such, for each county, a Board of Directors must be set up to oversee the IGO's operations, budget approval, staffing, establishing market rules, and approving subsequent changes. The IGO would then acquire existing dispatch, monitoring, and control equipment from the incumbent utilities in order to manage the transmission/distribution system. Market protocols would be developed by the IGO through stakeholder collaboration.

5.1.2 Impact on the roles and responsibilities of the Commission and utilities

Under the IGO model, utilities would continue to own and maintain the transmission and distribution system. However, utilities would need to yield their functions of system planning, dispatch, and day-to-day operations to the IGO. Under an IGO model, the incumbent utility could either retain its generation assets or divest them. Unlike the status quo model, this change would allow independent power producers ("IPPs") to compete with the HECO Companies on price (assuming a level playing field) over long-term contracts.

When it comes to roles, the PUC would continue to do most of its current responsibilities. These include the approval of resource planning, power purchase agreements ("PPAs"), financial transactions, large capital expenditures, service quality, and the regulation of rates. However, functions such as the coordination of movement of electricity, reliability, and long-term resource planning however, would be under the IGO's purview.

5.1.3 Compliance with reliability, adequacy, and quality of service standards

An IGO regulatory structure aims primarily to ensure that reliability standards are met. This would not only require collaboration on the part of the IGO itself but also amongst transmission owners and generators. In general, IGOs ensure that adequacy and reliability requirements are met by matching generation with demand with a least-cost combination of resources.

An IGO model would help utilities comply with reliability, adequacy, and quality of service standards established by the PUC. would contribute to maintenance and improvement of grid reliability by way of coordinating short-term grid operations. More specifically, the IGO would be responsible for functions such as:

- operational control of the transmission system within the region, security coordination, administration of the IGO tariff,
- operations of the transparent data access system, allocation of available transfer capability,
- provision or coordination of ancillary services, participation in transmission planning,
- implementation of congestion management procedures,

- coordination of generation and transmission, and maintenance scheduling.[41]

To ensure efficiency, an IGO must also identify constraints in the system and take necessary actions to alleviate the constraints within the trading rules established by the PUC.[42]

On the other hand, the transmission owners hold a set of different responsibilities. They may be responsible for functions such as maintenance of ownership of transmission facilities, physical operations and maintenance of transmission facilities, power systems analysis, transmission planning studies, and construction of new transmission facilities.

5.1.4 Ability to achieve State energy goals

The IGO model would be able to facilitate the achievement of some of the State energy goals such as in allowing improved market performance through the mitigation and/or elimination of market power as well as for increased competition within the marketplace (protecting consumers from monopoly power). More specifically, the IGO model would be able to facilitate the development of large renewable projects by increasing competition among utility-scale projects. As an independent body, system planning conducted by an IGO would also allow renewables to compete based on cost and value to the grid. However, without new initiatives, an IGO model at a distribution level would not substantially expand opportunities for DERs to participate (as opposed to a distribution-focused regulatory model that specifically addresses this issue). Finally, an IGO may be designed in such a way that most of the State energy goals are addressed in its mandate.

5.2 Financial feasibility

As a not-for-profit, non-taxed entity, an ISO, such as the ones that are currently operating (PJM, New York ISO, and ISO-New England) funds the services it provides through the collection of fees from market participants and customers that use regional transmission services. Service rates are set at a level that allows the ISO to recover its operational costs and the amount is determined annually through a budget process, which includes a robust external stakeholder review process. For these ISOs, the budgets should be filed with the FERC after the approval of the Board of Directors.[43] Hawaii does not fall under FERC jurisdiction so the IGO would report to the Commission, similar to that in Texas where ERCOT reports to the PUCT.

5.2.1 Financial requirements for implementation

Implementation costs of an IGO model vary, driven by a number of factors including the size of the market, market design, complexity of the auction and settlement processes, and extent of stakeholder and outreach levels. Each of these factors is a significant hurdle that must be overcome by any jurisdiction and carries a risk for cost overruns if not carefully managed and

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[41] FERC. *Order No. 2000 – Regional Transmission Organizations.* Docket No. RM99-2-000. December 20, 1999. Page 323.

[42] Ibid.

[43] Ibid.

designed. Annual operating budgets vary across regional ISOs in North America. Samples of 2017 costs—showing a range of $2.1/kW in Texas to $5.2/kW in Ontario—are in Figure 3. The Project Team has assessed the key cost factors for implementation of the IGO model based on regional ISO budgets.

Figure 3. Regional ISO Budgets

Market	Annual ISO Budget ($ '000)	Installed Capacity (MW)	Net Generation (GWh)	$ per kW	$ per kWh
California (CAISO)	$195,300	70,848	146,597	$2.76	$0.0013
New York (NYISO)	$148,200	44,570	116,082	$3.33	$0.0013
Ontario (IESO)	$191,400	36,945	144,300	$5.18	$0.0013
Texas (ERCOT)	$223,100	107,535	323,655	$2.07	$0.0007
Average				$3.33	$0.0012

Source: SNL; ISO Annual Reports and Business Plans

The Project Team notes that ERCOT, unlike the other markets, has a relatively simpler market structure (as it operates an energy-only market), as opposed to an administratively complex energy and capacity market as in California, New York, and Ontario. California and Ontario have centralized structures as well as wholesale markets, thereby, further increasing the complexity of those markets.

5.2.1.1 Market size and lack of interconnection

Hawaii's installed capacity of 3,427 MW is distributed across the different counties and islands, from 2,329 MW in Honolulu County (comprising the largest share) and 200 MW in Kauai County (the smallest).[44] The lack of an interconnection among the islands suggests that a wholesale market would be required in each of the islands and although the existing dispatch, monitoring, and control equipment (that manage the transmission/distribution system) already exists, market monitoring and settlement technology would be needed in each island to ensure data transparency.

Across North America, the smallest wholesale market is the one operated by the Alberta Electricity System Operator, with an installed capacity of approximately 16 GW. Within the context of islanded markets, in Mexico, the power grid of the state of Baja California is islanded from the rest of the Mexican grid. As a result, three markets operate in parallel, i.e., the National Interconnected System (*Sistema Interconectado Nacional*), Baja California Interconnected System, and Baja California Sur Electric System.[45] Similarly, in the Philippines—a country with more than 7,000 islands (which are mostly not interconnected)—there are three (3) wholesale markets

[44] HECO Companies' Power Supply Improvement Plans; KIUC website

[45] SENER; IEA, *Mexico Energy Outlook.* World Energy Outlook 2016

namely Luzon, Visayas, and Mindanao.[46] Effectively, there is one market operator overseeing three separate systems – the Luzon and Visayas grids have a high voltage direct current connection with limited inter-system trade. The Visayas system does include interconnections between some large islands, each with several hundred MWs of installed capacity. However, having one system operator across multiple systems helps to standardize market rules and achieve cost efficiencies. The Mindanao wholesale electricity market will also be under the same market operator once it becomes operational. Therefore, factors such as market size and lack of interconnection are important drivers of cost.

5.2.1.2 Market design and implementation

The costs of implementation of an IGO are not insignificant and include costs of acquisition of the utility's existing control room infrastructure, i.e., specific software and equipment used by the current utilities for system planning, dispatch, and day-to-day operations. Setting up an IGO also includes procurement of software and IT hardware and recruitment of personnel from the utility and outside, to name a few. In its assessment of start-up and operating costs for ISOs in the US upon inception by the end of 2004, FERC staff placed them between $50 and $70 million.[47] FERC's estimates involved a survey of four ISOs, namely, Midcontinent ISO, ERCOT, PJM, and Southwest Power Pool. A review of the cost categories suggests that not all costs—such as software procurement and IT system development—may need to be duplicated for a Hawaii-wide adoption of the ISO model. Others such as personnel recruitment and building costs would need to be replicated in each market.

5.2.2 Financial impact on the Commission, utilities, and ratepayers

From the perspective of ratepayers, the setup and operating costs of an IGO would fall on ratepayers. However, this would be balanced by likely market efficiencies from competition, that would ultimately benefiting customers.

The implementation of the IGO would likely result to additional costs for the Commission. More specifically, the Commission would need to create mechanisms for market monitoring, competition assessment, and dispute resolution, whether these would be assessed by the IGO, Commission itself or delegated to an independent third party.

The utilities would not be impacted financially by the implementation of an IGO model. Ultimately, the financial impact of the transition to an IGO regulatory model depends on the design of the transition and commitment of regulators toward full implementation. Regulatory uncertainty could be financially costly for both the utility and ratepayers and has been

[46] Although the Mindanao wholesale market was originally scheduled to be launched in June 2017, the commercial operations have been pushed back to the first half of 2019, according to a press release on October 2nd, 2018 by the Philippines Department of Energy.

[47] FERC Staff. *Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization.* Docket No. PL04-16-000. October 2004.

demonstrated to lead to adverse outcomes for all parties.[48] The textbox below shares the experience of New Brunswick as it dealt with challenges and barriers in the implementation of the ISO model.

New Brunswick: A Cautionary Tale

New Brunswick's electricity market is serviced almost entirely by New Brunswick Power Corporation ("NB Power"), a vertically integrated and provincially-owned Crown utility company responsible for most of the province's generation, transmission, and distribution. While NB Power has mostly served as a bundled utility since its inception, the Government of New Brunswick has also experimented with competitive electricity markets, beginning by unbundling the company's generation, transmission, and distribution assets in 2004.

In 2004, New Brunswick implemented the *Electricity Act*, which was passed one year earlier, whereby NB Power was divided into five separate companies, providing a legal and financial structure to support a decentralized organization. The benefits envisioned before restructuring did not materialize the way that the government intended. From 2003 to 2009, NB Power had the second-fastest increase in industrial electricity costs of any province in Canada, owing to various internal and external factors, such as rising fuel and debt servicing costs.

In October 2013, after nine years of limited competition in the generation sector, the Government of New Brunswick decided to amalgamate NB Power back into a single Crown company that services most of New Brunswick's generation, transmission, and distribution needs. The decision to revert to vertical integration was mainly because a competitive electricity market failed to develop, contrary to what policy makers had anticipated.

In October 2011, the government released a 10-year "Energy Blueprint" with the goal of reintegrating NB Power into a fully regulated and vertically integrated utility, citing the failure of a competitive market to develop and the need for cost reductions as the leading causes. In October 2013, the *Electricity Act* was amended, and all the companies separated in 2004 became amalgamated in NB Power once again. NB Power's de facto dominance of the separate businesses quickly became a significant barrier to entry for new market participants in terms of costs and grid access.

New Brunswick's experience from 2004 to 2013 illustrated potential challenges and barriers that could arise from the implementation of the ISO model. Furthermore, the *de facto* structure of the market hardly changed because NB Power remained as the holding company. Potential competitors had trouble gaining access to transmission and ancillary services, which are required to offer a complete supply package.

Sources: New Brunswick Department of Energy. *The New Brunswick Energy Blueprint*. New Brunswick: October 2011; Adams, Thomas. Borealis Energy Research Association. "New Brunswick's Power Failure: Choosing a Competitive Alternative." *Atlantic Institute for Market Studies*. October 2006.

[48] Joskow, P. *Lessons Learned from Electricity Market Liberalization*. The Energy Journal. 2008

5.3 Legal feasibility

This section assesses the capacity of the current legal and regulatory framework, significant legal and regulatory changes necessary, as well as any additional legal considerations in implementing the IGO regulatory model. Overall, there are at least two significant elements that must be considered in analyzing the legal feasibility of the IGO model: (i) functional unbundling of transmission service and establishment of open access transmission tariffs and related administrative and operational requirements for the existing utilities; and (ii) establishment, funding, and empowerment of an IGO entity.

5.3.1 Existing legal framework for the regulatory model

Currently, there is no existing legal framework for the IGO regulatory model in Hawaii. However, as discussed above, Hawaii law does provide broad supervisory and investigative powers. These powers have been used by the PUC to initiate proceedings regarding related issues including the need for an ISO-like entity as part of industry restructuring and intergovernmental wheeling. However, after several years of a lack of consensus among stakeholders on any significant issue raised in the docket, the PUC has not taken any action on these issues.[49] Moreover, some of the reliability functions that are expected to be performed by the IGO entity under the IGO regulatory model are governed by the HERA Law, as discussed above.[50]

5.3.2 PUC authority under current legal and regulatory framework

Hawaii's current legal and regulatory framework has no expressed authorization for the PUC to implement the IGO regulatory model. Depending on the specific structure and functions of the IGO entity, the PUC is likely authorized to implement some components of the IGO regulatory model through one or more administrative proceedings under its current general supervision, investigation, and ratemaking authority (through HRS Chapter 269). However, legislation may be needed to clarify the PUC's authority over the IGO entity and, as a practical matter, to incentivize the PUC to proceed with this particular course.

With respect to the functional unbundling of transmission service and the establishment of open access transmission tariffs and related administrative and operational requirements for the existing utilities, HRS Chapter 269 grants the PUC broad supervisory and investigatory powers over public utilities, administrative rulemaking authority pursuant to HRS Chapter 91, and authority over utility ratemaking. This which would likely enable the PUC to require the utilities to establish open access transmission tariffs, adjust accounting procedures, and enact and enforce

[49] PUC. Docket No. 96-0493, Order No. 15285, issued December 30, 1996 (electric restructuring for retail competition); PUC. Docket No. 96-0493, Decision & Order No. 20584, issued October 21, 2003 (closing the docket without taking action); PUC. Docket No. 2007-0176, Order No. 23530, issued June 29, 2007 (intergovernmental wheeling).

[50] HRS Chapter 269, Part IX. Electric Reliability.

other administrative and operational requirements required to implement the functional unbundling component of the IGO regulatory model.[51]

The PUC's general supervisory authority extends to the supervision of "public utilities" (as the term is defined under HRS § 269-1) as well as certain matters where non-utilities interact with public utilities.[52] The specific functions that the IGO entity performs, how it is constituted, and specific customers it serves would determine whether it may be subject to the PUC's broad direct supervisory authority as a public utility or not.[53] As such, the PUC may or may not have broad direct supervisory authority (including over the ability to establish rates for its services and the rule with which it must comply) over the IGO entity as a public utility. Moreover, under the HERA Law, the PUC is authorized to delegate certain functions to a third party, including the function of acting as HERA. [54] However, as state earlier, the PUC is not permitted to contract a public utility that can serve as HERA.[55] As such, under the current Hawaii law, it may be possible for an IGO entity to function as HERA as long as it is not a public utility under HRS Chapter 269. If an ISO or IGO would otherwise be deemed to be a public utility under HRS Chapter 269, legislation would be required to add an exemption for IGOs in the definition of public utility.[56]

5.3.3 Statutory changes or laws required for implementation

At the minimum, legislation should be introduced to clarify the PUC's oversight of the IGO entity and permit any funding mechanism. This could include clarifying the PUC's authority to regulate the IGO entity as a public utility and modifying the HERA Law to permit a public utility to serve as an IGO that would perform the HERA role. Alternatively, this could be achieved by excluding the IGO entity from the definition of public utility (similar to that for independent organizations

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[51] HRS §§ 269-6, 269-7.

[52] HRS §§ 269-6(a), 269-7, 269-15.

[53] As defined under HRS § 269-1, the term "public utility" includes:

> every person who may own, control, operate, or manage as owner, lessee, trustee, receiver, or otherwise, whether under a franchise, charter, license, articles of association, or otherwise, any plant or equipment, or any part thereof, directly or indirectly for public use . . . for the production, conveyance, transmission, delivery, or furnishing of . . . power [.]

HRS § 269-1 (emphasis added). Under Hawaii law, a person that does not "hold himself out, expressly or impliedly, as engaged in the business of supplying his product or service to the public, as a class, or to any limited portion of it, as contradistinguished from holding himself out as serving or ready to serve only particular individuals" is not a "public utility". *Application of Wind Power Pac. Inv'rs-III*, 686 P.2d 831, 834 (Haw. 1984).

[54] HRS § 269-147(a).

[55] HRS § 269-147.

[56] See, HRS § 269-1.

as used by ERCOT)[57] and drafting a new statutory framework or modifications (e.g., that provide for oversight and funding) to the existing HERA Law.

Legislation is not required to initiate the functional unbundling of transmission or establishment of open access non-discriminatory transmission tariffs. However, a law that mandates the functional unbundling of transmission and establishment of an IGO entity may increase certainty about the intended outcome of the associated PUC proceedings, reduce objections to a PUC initiated process, and ensure follow through by the PUC, which may prioritize its resources toward issues and objectives that are required by the legislature.

5.3.4 Administrative actions required by the PUC

Significant regulatory changes are necessary to implement the IGO model. The precise nature of the changes would depend on whether the IGO entity is treated as a public utility in the way FERC regulates ISOs (i.e., as a unique independent organization similar to how PUCT currently regulates ERCOT) or as a PUC contractor consistent with the current HERA Law.[58]

Whether as a result of legislative requirements or the PUC's own initiative, the PUC would need to undertake at least one or more investigative, ratemaking, and/or rulemaking proceedings. These include proceedings to: (i) develop open access non-discriminatory transmission tariffs for the incumbent utilities; (ii) determine administrative and operational requirements, such as a transparent data access system, for the IGO to function; (iii) issue a certificate of public convenience and necessity to the IGO entity, if regulated as a public utility; (iv) establish an IGO tariff, if regulated as a public utility; (v) provide for the division of roles and responsibilities between the ISO and the incumbent utility; and (vi) implement statutory requirements for fees and governance, if applicable.

5.3.5 Additional legal issues

Currently, in each island, Hawaii's electric utilities have various existing PUC-approved PPAs with various IPPs. To the extent that the IGO entity functions to procure and dispatch generation resources, the existing PPAs must be dealt with in a way that does not violate the Contract Clause of the United States Constitution (the "Contracts Clause").[59] Any laws or regulations that

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[57] *See* Tex. Util. Code Ann. § 39.151.

[58] FERC generally regulates ISOs and RTOs as public utilities and they are funded pursuant to FERC approved tariffs. GAO, Electricity Restructuring, GAO-08-987, (Sept. 2008) ("Because RTOs charge for the use of transmission lines, for certain wholesale sales of electricity, and to recover their own expenses, they are subject to FERC oversight and regulation."), accessed at https://www.ferc.gov/industries/electric/indus-act/rto/gao-report.pdf. In contrast, ERCOT is regulated by PUCT as an "independent organization" under separate statutory authority and is funded pursuant to a PUCT approved budget. Tex. Util. Code Ann. § 39.151. Under the current HERA law, the HERA, if constituted, is a contractor. *See* HRS § 269-147.

[59] U.S. Const., art. I, § 10, cl. 1.

substantially impair an existing contractual relationship may be found unconstitutional if they are not drawn reasonably and narrowly to serve a significant and legitimate public purpose.[60]

5.4 Conclusion

The IGO model has demonstrable technical, financial, and legal feasibility challenges—with the need for multiple new entities in each county and acquisition of dispatch and control software, along with market design and implementation, among the key risks. The benefits of open access and lack of interconnection bias are ideal for achieving state energy goals and existing personnel and infrastructure may lower start-up costs. That being said, there are considerable risks to the implementation of this model with respect to its technical, financial, and legal feasibility, (Figure 4). Therefore, this model ranks under *medium risk* in its overall feasibility.

Figure 4. IGO Model: Feasibility Criteria Summary

Criteria	Categorization	Various Considerations
Technical Feasibility	Implications for role and responsibilities	(+/-) Depends on scope of mandate of IGO
	Compliance with service standards	(+) IGO would be responsible for short term reliability
	Achievement of State clean energy goals	(+/-) Open access and lack of interconnection bias offset by lack of addressing incentives for DERS
Financial Feasibility	Implementation requirements	(+/-) Depends on the transition process
	Impact on ratepayers	(-) Potential for stranded costs falling on customers
		(-) Setup and operating costs of implementation
	Impact on utilities	(+/-) Depends on whether utilities are able to capture market efficiencies
Legal Feasibility	Existence of supporting legal framework	(-) Not currently an existing legal framework for the IGO regulatory model in Hawaii
	Governance requirements	(-) PUC will need to undertake at least one or more investigative, ratemaking, and/or rulemaking proceedings
	Additional legal factors	(-) PUC-approved PPAs will need to be dealt with appropriately

Source: LEI analysis

[60] *Applications of Herrick*, 922 P.2d 942, 954 (Haw. 1996).

6 Distribution-focused regulatory model

The distribution-focused regulatory or Distributed System Platform Provider ("DSPP") model envisions that the utility serves as the DSPP. Currently, New York is the only state that has concrete plans of moving forward to a distribution-focused regulatory model. New York's Reforming the Energy Vision ("REV") model, which aims to increase the use of clean energy and increase customer participation in the electricity sector, has energy goals similar to Hawaii's. Under the DSPP model, the distribution system would be owned and operated by the utilities. Similar to NY's REV, the Project Team anticipates that the DSPP would be responsible for designing and planning the distribution system, which would help integrate DERs.

6.1 Technical feasibility

6.1.1 Requirements for establishment

The transition to DSPP could be lengthy and complex. More specifically, moving to a DSPP model necessitates piloting new and different ways to operate the electricity system and work with third-party DER providers. It also requires having a different business/ownership model for the utility as highlighted in Task 1.

As discussed in Task 2.1.1, Hawaii has high levels of DER adoption and state policy promotion but lagging in infrastructure investment. This is Stage 2 of the DER adoption curve. To be able to move to the DSPP model, Stage 2 requires enhanced functional capabilities for reliable distribution operations[61], thereby necessitating changes in grid planning and operations in order to accommodate DERs at their levels as well as provide system-wide benefits.

The HECO Companies launched the Grid Modernization Strategy, which would ultimately aid in infrastructure improvements. In combination with the implementation of the proposed DSPP model, this strategy would likely propel the State to move forward toward Stage 3 (Distributed Markets) of the DER adoption curve (possibly closer to California's stage). The highlights of the first phase of the strategy include deployment of advanced meters, launch of a meter data management system, and implementation of a telecommunications network. The first phase will be implemented from 2019 to 2023.[62]

To implement the DSPP model, the Hawaii PUC would first need to initiate discussions (particularly in defining the DSPP) amongst relevant stakeholders. This step may be a lengthy process as seen in New York's REV model (Task 2.1.1 and Task 2.2.2), which lasted approximately 11 months. In doing so, the PUC must also establish clear guidelines pertaining to the roles and responsibilities of the DSPP, based on the stakeholdering process and regulatory structure. For instance, as recommended in Task 2.2.2, the PUC may need to restrict utilities from owning local

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[61] Martini, P. and Kristov, L. *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation, and Oversight.* Lawrence Berkeley National Laboratory. Report No. 2. October 2015.

[62] "Hawaiian Electric Companies take steps to implement first phase of grid modernization strategy." *Maui Electric Hawaii Electric Light.* June 21, 2018. Web. July 30, 2018. <https://www.hawaiianelectric.com/hawaiian-electric-companies-take-steps-to-implement-first-phase-of-grid-modernization-strategy>

power generation to ensure fair competition. The Hawaii PUC would then order the utilities to take the new role of the DSPP on. The Hawaii PUC should also review the existing regulatory model and ratemaking approach and revise items so that they would be in line with the utilities' new role. Furthermore, the PUC must then develop a distribution use of system charge that would facilitate wheeling within the distribution system.

6.1.2 Impact on the roles and responsibilities of the Commission

To assess any additional infrastructure or capabilities the DSPP model may require of the Commission, the Commission must first consider the status of DER adoption in the State of Hawaii, how prepared utilities are in integrating DERs, and how the existing rate design affects DERs.[63] As mentioned, Hawaii falls under Stage 2 of the DER adoption curve, signifying that Hawaii currently has moderate to high levels of DER penetration in the State. Behind-the-meter generation resources or distributed generation in Hawaii predominantly consist of rooftop solar photovoltaic ("PV") panels. In combination with the Grid Modernization Strategy, the DSPP model would support the State's move towards Stage 3 by providing a platform for increased penetration of renewables and DERs. This growing presence of DERs would call for the regulator's focus on the system at a distribution level as this is where DERs predominantly affect the system. As such, under the distribution-focused regulatory model, the Commission may require increased "*visibility into and oversight of the planning of a utility's circuits and broader distribution system.*"[64]

Under the DSPP model, the PUC must ensure fair competition in the distribution marketplace along its current responsibilities (detailed in Task 2.1.2). The Commission would monitor open access and encourage the utilities to provide a platform for third-party DER providers—thereby creating value for both customers and the grid. This could be achieved either through explicit orders or incentives within existing ratemaking.

To accommodate the aforementioned additional capabilities, thus, achieve increased visibility and oversight of the distribution system, the Commission would require access to certain data (e.g., those essential in the analysis of the grid design and optimization as well as planned investments). This data includes, but is not limited to, grid needs by technical characteristics (e.g., capacity, reactive power, voltage, resiliency, spinning/non-spinning reserves etc.), geographic location, and installed DER capacity and forecasted growth by circuit.[65] The provision of this data may necessitate advanced technologies that could support the Commission in making informed decisions regarding rate design and DER compensation, responding to any changes in the pace of DER adoption, and identifying the level of adoption of DERs across a jurisdiction.

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[63] National Association of Regulatory Utility Commissioners. *NARUC Manual on Distributed Energy Resources Rate Design and Compensation*. November 2016.

[64] Ibid, page 146.

[65] Ibid, page 148.

Overall, the integration of DERs, particularly when exporting electricity to the grid, may introduce system planning complexities for the utility. The utility would remain responsible for maintaining and upgrading the system for reliability purposes, thus, this new regulatory model may necessitate new investments to allow two-way electricity flow.[66] Put differently, utilities may need to upgrade distribution equipment if circuits export to the grid and act as step-up facilities.[67]

Moreover, to further facilitate the adoption levels of DERs, utilities may opt for additional infrastructure and technologies that can help maintain reliability within the distribution grid as well as enhance resilience. As per the National Association of Regulatory Utility Commissioners ("NARUC"), utilities may consider two options: (i) Advanced Distribution Management System; ("ADMS") and (ii) Distributed Energy Resource Management Systems ("DERMS").[68] The implementation of ADMS would enable the distribution utility to examine real-time conditions readily across its service territory through increased communication and visibility of the distribution grid. More specifically, this tool would provide utilities with functions including, but not limited to: (i) fault location, isolation, and service restoration; (ii) conservation voltage reduction; and (iii) volt/VAR optimization.[69] DERMS, on the other hand, would enhance utilities' ability further by allowing utilities to "*dispatch resources, both on the utility side and the customer side; forecast supply and demand conditions up to 24-48 hours in advance; better integrate AMI data with other utility systems, such as ADMS, outage management, and weather systems; and communicate with third-party/aggregator systems.*"[70] DERMS could be used in islanding and microgrids.[71] All in all, technology solutions such as ADMS and DERMS would aid distribution utilities in planning and operating DERs as they continue to be adopted across their respective service territories, ultimately aiding the Commission in decisions regarding rate design, DER compensation, and identifying cross-jurisdictional DER adoption levels.

Moreover, in order to move closer towards Stage 3 of DER adoption (which results from high levels of DER adoption and policy decisions to create distribution-level energy markets for multi-party transactions), the Commission would also need to implement changes that enable retail energy transactions, including those "*within a local distribution area defined by a single [transmission-*

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[66] National Association of Regulatory Utility Commissioners. *NARUC Manual on Distributed Energy Resources Rate Design and Compensation.* November 2016. Page 16.

[67] DeMartini & Kristov. *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation & Oversight.* Lawrence Berkeley National Lab. October 2015

[68] National Association of Regulatory Utility Commissioners. *NARUC Manual on Distributed Energy Resources Rate Design and Compensation.* November 2016. Page 52.

[69] Department of Energy. *Voices of Experience: Insights into Advanced Distribution Management Systems. Department of Energy*, Washington, D.C. February 2015. Web. Access date: June 6, 2018. <ttps://www.smartgrid.gov/files/ADMS-Guide_2-11.2015.pdf>

[70] Jeff St. John. *Inside SDG&E's Plan to Optimize the Distributed Grid of the Future*. Greentech Media. May 16, 2014. <http://www.greentechmedia.com/articles/read/sdge-and-spirae-break-new-ground-on-the-grid-edge>.

[71] National Association of Regulatory Utility Commissioners. *NARUC Manual on Distributed Energy Resources Rate Design and Compensation.* November 2016. Page 53.

distribution] interface substation, thus not relying on transmission service."[72] In other words, the Commission would need to establish a peer-to-peer ("P2P") energy transaction platform as a "*next-generation energy management mechanism*", thereby allowing prosumers of the network to trade with one another as well as the grid also.[73] Similar to online platforms for retail goods, the P2P energy trading platform would serve as an online marketplace for electricity products and services. While such a platform has been adopted for microgrid systems[74], it is yet to be realized in other markets.

Finally, the success of this regulatory model hinges on the distribution utilities' capabilities, including on advanced grid platform technologies and operating procedures such as for cases when they need to call upon the DERs (as per need in real time) and in monitoring the latter's visibility so their performance may be tracked. It is also upon the utility to "*develop methods to identify needs of the system by location, determine hosting capacity, assess potential benefits of DERs on a particular feeder and distribute DERs optimally*" within the distribution service area.[75]

6.1.3 Impact on the roles and responsibilities of utilities

If utilities would take on the role of the DSPP, the PUC may restrict them from owning local power generation to avoid the occurrence of vertical market power. This challenge currently exists in Hawaii because utilities own and operate generation, transmission, and distribution. As such, with DSPPs owning DERs, the vertical market power may would be exacerbated even further.

6.1.4 Compliance with reliability, adequacy, and quality of service standards

The DSPP model would be able to ensure that influx of DERs may not pose a significant threat to the reliability of the power system. As discussed in Section 6.1.2, the DSPP model would be able to ensure that there is balance between reliability and potential increase of DERs in the system (through careful planning) as well as additional infrastructure and technologies, which may be adopted by utilities—all of these would likely contribute to the increased and improved visibility and oversight of the distribution system by the PUC.

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[72] DeMartini & Kristov. *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation & Oversight.* Lawrence Berkeley National Lab. October 2015

[73] IEEE. *Transforming Energy Networks via Peer to Peer Energy Trading: Potential of Game Theoretic Approaches.* March 19, 2018. <https://arxiv.org/pdf/1804.00962.pdf>

[74] As an example, LO3 Energy and Siemens created a pilot microgrid in Brooklyn, New York. The system allows solar panel owners to trade energy with their neighbors using blockchain technology. (Source: "The Brooklyn microgrid: blockchain-enabled community power". *Power Technology*. April 11, 2017. Web. July 16, 2018. <https://www.power-technology.com/features/featurethe-brooklyn-microgrid-blockchain-enabled-community-power-5783564/>

[75] DeMartini & Kristov. *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation & Oversight.* Lawrence Berkeley National Lab. October 2015.

6.1.5 Ability to achieve State energy goals

A DSSP model would be able to support the growth of DERs by incorporating them in distribution-level planning, allowing them to provide grid services, and facilitating direct transactions with other customers.

The facilitation of DERs through the distribution-focused regulatory model would aid the State in diversifying its energy mix as well as in its pursuit of "*de-carbonization of electricity supply*."[76] Moreover, DER products available in the market may optimize environmental benefits by way of, for instance, the incorporation of a range of electric vehicle purchase and charging incentives, including lifecycle assessment of emissions.

Moreover, the State of Hawaii aims to have an efficient marketplace that is beneficial to both producers and consumers.[77] As such, the DSPP model could lead to lower costs to consumers as they shift consumption away from the grid during peak hours through DERs as well as impact of efficiency gains from competition, which will likely result from behind-the-meter markets. Furthermore, the increased integration of DERs would likely reduce distribution grid costs, thereby further maximizing consumer cost savings.

6.2 Financial feasibility

6.2.1 Financial requirements for implementation

As discussed in Task 2.1.1, the DSPP model has not yet been implemented to completion in any jurisdiction. Therefore, only high-level estimates on the financial requirements of its implementation can be made and for the purposes of this analysis, we will focus on the financial requirements for open access.

The grid platform technologies that would help facilitate the transition of a utility into becoming a DSPP would require significant investment, which could ultimately be recovered from ratepayers. Section 6.1.2 identified some of the infrastructure needs toward transition to the DSPP.

In addition, this model would require significant outreach and customer education efforts as well as careful market design to promote competitive market participation. The example of New York is prescriptive in illustrating the financial requirements of this model. Currently, the implementation of the REV model has taken place through a step-wise manner, with more focused and targeted milestones in each step. To facilitate the transition, the utilities have been required to file Distributed System Implementation Plans ("DSIPs"), which outline near- to

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[76] SolarCity Grid Engineering. *A Pathway to the Distributed Grid: Evaluating the economics of distributed energy resources and outlining a pathway to capturing their potential value.* White paper. February 2016.

[77] Hawaii State Energy Office, Hawaii Department of Business, Economic Development, and Tourism, "Energy Policy Directives," March 2017, available at https://energy.Hawai'i.gov/wp-content/uploads/2011/08/EnergyPolicy_1pgr_rev-Mar2017.pdf

medium-term investment plans that they need to execute in order to facilitate greater DER penetration in their networks.

In one example, ConEdison indicated in its DSIP that it will spend $214 million in capital investments to facilitate system expansion for DERs—a plan that includes a roadmap to integrate 800 MW of DERs by 2020.[78] ConEdison's DSIP also provides a hosting capacity map of its existing network of stakeholders; a step that may be considered as a foundation of its role as a DSPP.[79] As discussed in Task 1.1.4, estimates of the capital expenditure ("capex") costs in establishing this model ranged from between about $20 million to more than $250 million over five years, based in the experiences of New York.[80] Estimating the costs for Hawaii's utilities would require a thorough study of the existing infrastructure of the utilities and enabling technologies specific to each county along with assumptions of the distribution-focused regulatory framework.

6.2.2 Financial impact on the Commission, utilities, and ratepayers

As discussed in Section 6.1.2, additional infrastructure and technologies are needed to be able to implement the DSPP model. The Project Team assumes that these infrastructure and technologies would be included under the rate base of the utilities, thus, borne by the ratepayers.

Under the DSSP model, ratemaking would need to be modified, with different degrees of impact on the utility and ratepayers. The cost-of-service ("COS") approach would still be used in combination with market-based platform earnings and outcome-based earning opportunities (similar to what New York's REV is proposing).[81] More specifically, the REV provides a framework that illustrates how utility earnings could be achieved under the distribution-focused model, for example, through: (1) traditional COS earnings; (2) earnings tied to achievement of alternatives that reduce utility capital spending and provide definitive consumer benefit; (3) earnings from market-facing platform activities; and (4) transitional outcome-based performance measures.[82] . This conceptual framework of utility earning mechanisms from a DSPP model is applicable to the Hawaii context as it illustrates the potential impact of the financial framework to the utility. For Hawaii, this presents a pathway of options for how a DSPP model may restructure the financial paradigm of the sector. A practical example of how this framework could

[78] Con Edison. *Distributed System Implementation Plan (DSIP).* June 30, 2016.

[79] Ibid.

[80] In Task 1.1.4, the Project Team assessed the future needs for generation, transmission, and distribution infrastructure within each county, and within the context of each ownership model. A more detailed discussion of the needs that would arise from the move to an IDER ownership model is undertaken in this memo.

[81] NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision,* Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, (issued and effective May 19, 2016) (Track Two Order). Page 2.

[82] Ibid, Page 2.

be implemented is discussed in the textbox below, where a case example of a DSPP project in New York is discussed.

Potential Utility Earning Mechanisms from a DSPP Model Under REV

In their traditional COS earnings, the utilities will earn a return on their rate base following their existing ratemaking schedule and procedures. Under the second track, the utilities' earnings are tied to achievement of alternatives that reduce capital spending. The Brooklyn Queens Demand Management case study is a prescriptive example, whereby the regulator recognized the utility's forfeiture of capital investment and authorized a return on total program expenditures as well as offered performance incentives tied to achievement of goals that will lead to more customer savings.[1]

Under the third track, the utility will see potential earnings from market-facing platform activities particularly as designed in the value stack approach of valuing DER solutions. The New York Department of Public Service staff's assessment of this track of earnings envisions "Platform Service Revenues" ("PSRs") for the utility. PSRs will be earned by utilities through their provision of services (to market participants) as DSPPs. Examples of some of these revenues include customer origination via the online portal, data analysis, co-branding, transaction and/or platform access fees, optimization or scheduling services that add value to DER, advertising, energy services financing, engineering services for microgrids, and enhanced power quality services. Furthermore, it is envisioned that through this revenue stream, increased PSRs would encourage utilities to support access to their systems by DER providers and offset required base revenues derived from ratepayers.[1]

The fourth track of potential earnings are utility incentives that are tied to near-term measures undertaken by the utility to create customer savings and develop market-enabling tools. The incentive mechanisms are designed to align "*the utilities financial interests with the regulator's REV objectives*" with the goal that the incentives play a transitional role until other forms of market-based revenues are available at scale. Incentives recommended by the New York regulator relate to peak efficiency (aimed at near-term system savings and development of DERs), customer engagement (aimed at educating and engaging customers and providing access to data), affordability (aimed at low-income customer participation in DERs), and interconnection (aimed at increasing speed and affordability of interconnecting DERs).[1] Importantly, these incentives vary in their symmetry i.e., positive (no penalty if targets are not met), negative (no reward if targets are met), and bi-directional.

Source: NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision,* Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, (issued and effective May 19, 2016)

Implementing a DSPP solution in New York State

Among the demonstration projects filed under the REV Distributed System Platform ("DSP") project was a solution involving Niagara Mohawk Power Corporation, a subsidiary of National Grid USA, the Buffalo Niagara Medical Campus Inc. ("BNMC"), and Opus One Solutions ("Opus One"). BNMC is a network of 13 institutions and nearly 100 public and private companies while Opus One is a software engineering company offering distribution grid solutions for the project. This project seeks to test a centralized DSP that would communicate with network-connected points of control ("POC") associated with BNMC's network of DERs, which are described further below.

National Grid's Elm Street substation provides power to the BNMC through local distribution stations (via underground 23 kV circuits) and is the central distribution point for most of the BNMC buildings. BNMC's current DER capacity is over 34 MW with about 28 MW consisting of diesel generators and approximately 1 MW from demand response. Furthermore, BNMC is currently evaluating increasing its DER capacity by adding 19 MW of natural gas generation, 1 MW of solar PV, and 150 kW of battery storage.

The proposed DSP would be designed to communicate system needs of the Elm Street substation and local feeders and send dynamic pricing signals to the POCs through the Opus One-designed platform. The control points would then communicate with the DSP as to the availability of BNMC's DERs that could respond to electric system needs and, crucially, their willingness-to-accept pricing signals. Within the BNMC "market", the project seeks to evaluate at what price points the BNMC DERs are willing to provide system services as well as what level of revenues would motivate further DER development.

Noteworthy is the cost estimates provided by National Grid for the project as well as the proposed revenue models for the utility. The project's total cost has been estimated at $6.8 million with $4 million attributed to software development capital expenditure and annual operating expenses of $230,000. By way of revenue models, National Grid has proposed a number of options to leverage the platform once development is complete. The first is provision of one-time data as a service about distribution optimization opportunities to help BNMC members make decisions on their potential investments in DER assets. The second is provision of access to the DSP through a monthly or annual fee or a license or contractual agreement with the ownership party.

Sources: New York Department of Public Service. *Staff Proposal: Distributed System Implementation Plan Guidance.* Case 14-M-0101. October 2015; National Grid. *Proposed REV Demonstration Project: Distributed System Platform*. June 2016.

6.3 Legal feasibility

Significant elements must be considered in analyzing the legal feasibility of the DSPP model. The DSPP model requires the following: (i) functional unbundling of distribution service and establishment of open access distribution tariffs and related obligations for the existing utilities; (ii) establishment of platform and outcome-based revenue mechanisms; and (iii) establishment of standards for utility participation in the DER marketplace. The model may also require the incumbent utilities' divesture of distribution utility assets and functions.

6.3.1 Existing legal framework for the regulatory model

There is currently no existing legal framework that expressly governs the regulatory model in Hawaii. However, as discussed above, Hawaii law does provide broad supervisory and investigative powers through HRS Chapter 269, which allow the PUC to develop policies, rules, standards, practices, and other requirements applicable to public utilities.

6.3.2 PUC authority under current legal and regulatory framework

Hawaii's current legal and regulatory framework has no expressed authorization for the PUC to implement the DSSP regulatory model. Nevertheless, the PUC is likely authorized to implement some components of this models through one or more administrative proceedings under its current general supervision, investigation, and ratemaking authority through HRS Chapter 269. However, while the DSPP (through its ownership and operation of facilities) may be regulated by the PUC as a public utility, additional legislation may be needed to allow the DSPP to take certain reliability oversight roles on.

When it comes to the functional unbundling (discussed in Section 5.3) of distribution service required for the DSPP regulatory model, HRS Chapter 269 grants the PUC broad supervisory and investigatory powers over public utilities, administrative rulemaking authority (pursuant to HRS Chapter 91), and authority over utility ratemaking.[83] This would likely enable the PUC to require the utilities to establish open access distribution tariffs, establish platform and outcome-based revenue mechanisms, adjust accounting procedures, and enact and enforce other administrative and operational requirements as required in implementing the functional unbundling of distribution service and establishment of open access distribution tariffs and related administrative and operational requirements. Moreover, this would allow the PUC to establish standards for third-party participation in the DER marketplace under the DSPP model.

The PUC's general supervisory authority extends to the supervision of "public utilities" as the term is defined under HRS § 269-1 as well as certain matters where non-utilities interact with public utilities.[84] Under the DSPP model, the PUC would almost certainly have broad direct supervisory authority over a DSPP as a public utility because the latter owns and operates distribution facilities, which interconnect with the general public.

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[83] *See* HRS §§ 269-6, 269-7.

[84] *See* HRS §§ 269-6(a), 269-7, 269-15.

6.3.3 Statutory changes or laws required for implementation

When it comes to the functional unbundling of transmission (discussed in Section 5.3), no legislation is required to initiate the functional unbundling of distribution services, establishment of platform or outcome-based revenue mechanisms, or setting of open access non-discriminatory distribution tariffs.

6.3.4 Administrative actions required by the PUC

Significant regulatory changes are necessary to implement the DSSP model. Whether as a result of legislative requirements or the PUC's own initiative, the PUC would need to undertake at least one or more investigative, ratemaking, and/or rulemaking proceedings. These may include proceedings to (i) develop open access non-discriminatory distribution tariffs for the incumbent utilities, (ii) establish platform and outcome-based revenue mechanisms, (iii) issue a certificate of public convenience and necessity to the DSPP entity, (iv) implement statutory requirements for fees and governance, if applicable, and (v) approve utility asset divestiture, if needed for the DSPP model.

6.3.5 Additional legal issues

As discussed in Section 5.3.5, any law or regulation that substantially impairs an existing contractual relationship may be found unconstitutional if it is not drawn reasonably and narrowly to serve a significant and legitimate public purpose.[85] Where a new distribution utility assumes a role that impacts contractual arrangements for grid access (e.g., for customer sited DER or for IPPs), existing interconnection agreements and related arrangements must be dealt with in a way that does not violate the Contract Clause.

6.4 Conclusion

The DSPP model has demonstrable technical implementation, financial feasibility, and legal feasibility risks particularly given the lack of global best practices to draw examples from. The roles and responsibilities of both the Commission and the utilities would change significantly as the regulator must design and implement a new ratemaking paradigm and the utilities transition to a power system that promotes greater DER penetration and open access of the distribution grid. While it presents potential benefits, there is significant implementation risk. As a result, the Project Team believes that the DSPP model has a high level of feasibility risk (Figure 5).

[85] *Applications of Herrick*, 922 P.2d 942, 954 (Haw. 1996).

Figure 5. DSPP Model: Feasibility Criteria Summary

Criteria	Categorization	Various Considerations
Technical Feasibility	Implications for role and responsibilities	(+) Significant changes in roles for both commission and utilities, requiring careful transition
	Compliance with service standards	(+/-) Depends on enforcement of standards at various scales of DER penetration
	Achievement of State clean energy goals	(+) Increased DER growth and market participation from consumers
Financial Feasibility	Implementation requirements	(+/-) Requires careful market design
	Impact on ratepayers	(+/-) Increased benefits from consumer participation and DERs possible
	Impact on utilities	(+/-) Depends on effectiveness of transition to DER-focused system
Legal Feasibility	Existence of supporting legal framework	(-) Not currently an existing legal framework for this regulatory model in Hawaii
	Governance requirements	(-) PUC will need to undertake at least one or more investigative, ratemaking, and/or rulemaking proceedings
	Additional legal factors	(-) PUC-approved PPAs will need to be dealt with appropriately

Source: LEI analysis

7 Performance-based regulation model

PBR, as a regulatory approach to rate regulation, provides a wide range of mechanisms, which allow the link between a utility's rates and its unit costs to weaken, thus, improving efficiency. It is best conceptualized as a continuum, ranging from "light" to "comprehensive" mechanisms, rather than a single type of regulatory regime as discussed in Task 2.1.1.

The Project Team envisions three possible variants of the PBR model, building on current PBR components as well as the proposed PBR for Hawaii:

- Option 1: Light PBR employs an expanded list of performance incentive mechanisms ("PIMs") with the current earnings-sharing mechanism ("ESM");
- Option 2: Conventional PBR employs a revenue cap with an indexation formula;
- Option 3: Outcomes-based PBR approach.

This section considers the feasibility of the PBR model and details the technical, financial and legal implications should the model be implemented in each level of the PBR continuum.

7.1 Technical feasibility

7.1.1 Requirements for establishment of PBR

Moving from a traditional COS regime to any variant of PBR can be a challenging task, not only for the regulator but for the utilities as well, especially during the first generation/term. It involves extensive amount of regulatory work and requires lengthy stakeholder engagement efforts particularly in determining the appropriate PBR mechanism allowing more in-depth analysis of sectoral and technical issues—discussions of which are not always present or as thoroughly dissected during a COS deliberation.

The first 'formal' step in the PBR process is when the regulator expresses its intent to implement a shift. In this step, the regulator would be expected to explain the objectives clearly to all stakeholders as it embarks in the process. For example, in the case of Alberta, the Commission highlighted the goal of developing a regulatory framework that allows incentives for the regulated companies toward improvement of efficiency while ensuring that benefits from the increase in efficiency will ultimately benefit customers.[86]

The following principles need to be assessed collectively so the goals of the move to PBR may be determined as the State decides upon a regulatory regime or a change in regime:

[86] Alberta Utilities Commission. Rate Regulation Initiative Decision 2012-237. September 12, 2012. Page 5. Accessed at: <http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-237.pdf>

- ***Incentives compatibility:*** Ratemaking should provide appropriate incentives to both companies and customers (although some natural conflicts may occur, and tradeoffs made).

- ***Financial stability and fair (commercially reasonable) rate of return***: Rates must be set at a level which enables the utility to meet its statutory obligations to serve while earning a commercially reasonable return (which continues to attract investors given the business risks) and sufficient cash flow to support necessary investment.

- ***Administrative simplicity and transparency***: Rates should be straightforward for customers to understand; customers should be able to calculate their monthly bills themselves and understand why the rate is calculated in the prescribed fashion.

- ***Cost causation and avoidance of cross-subsidies***: To achieve the most efficient patterns of consumption, economic theory states that customers that cause a cost to be incurred should pay for that cost.

- ***Non-discrimination***: Similarly situated customers should face similar terms and conditions.

Experience and best practice dictate that the shift to a PBR mechanism requires the establishment of principles that should guide stakeholders (particularly the utilities) in the development and implementation process. The establishment of these principles assists the regulator in evaluating PBR proposals and guides the utilities in developing the most responsive and relevant proposals.

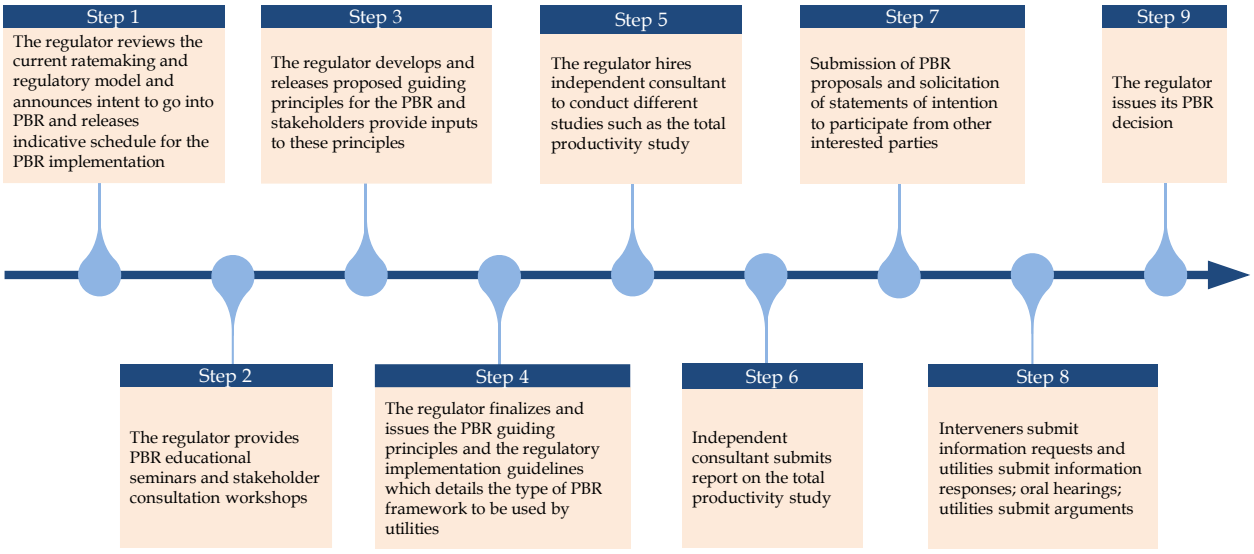
The move to PBR may also involve the hiring of an economic consultant who could assist in determining the appropriate PBR approach, identifying appropriate components (such as incentives and magnitude of rewards or penalties for the performance standards), reviewing what data is currently available, or providing a study of historical and forecasts of inflation and productivity trends. It is also crucial that the regulators and stakeholders be regularly communicating and on the same level of understanding. Workshops and technical conferences are generally conducted to familiarize stakeholders with the proposed PBR approach and solicit feedback.

The typical high-level steps involved in the transition to a PBR model are illustrated in Figure 6.

The feasibility of PBR requires two essential elements: data availability and forecasting. Data availability plays a vital role in the development of a PBR regime and would improve the functionality of PBR regulation over time. Data could often be inconsistent or unavailable because of differing or lack of clear reporting guidelines, varying cost allocation methods employed by each utility, changes and differences in accounting techniques, and mergers and amalgamations, among others. The need for good data cannot be understated; incentive design could be significantly weakened by poor data. "Comprehensive" forms of PBR require collating and employing multi-period information and data samples covering multiple utilities. Over time, the availability of reliable, comparable, and accurate data on the industry and the utilization of "best practice" forecasting tools would improve the ease of the PBR ratemaking process. By doing so, this facilitates analysis and negotiations of parameters for PBR factors as well as benchmarking

actual productivity achieved against prior targets. Ensuring data consistency and credibility requires configuring systems and processes correctly. Utilities could review current systems and record-keeping practices and configure them to capture the data required for filing. Appointing a Chief Data Officer, who could ascertain data accuracy and consistency, would be useful to prevent errors.

Figure 6. High-level Steps in the Move to PBR



Source: LEI analysis

Furthermore, the preparation of PBR filings requires the ability to forecast additional elements that may have been less critical under a COS regime.[87] Forecasting plays a central role in the building blocks approach-based PBR. Poor forecasting by utilities may lead to additional costs and/or penalties affecting their bottom line. Realistically speaking, forecasts could significantly deviate from actual figures. Therefore, the PBR design must include mechanisms that would provide a degree of protection to both shareholders and ratepayers. Such mechanisms may include re-openers, ESM, true-ups, rebasing, and flow-throughs.[88] Benchmarking and trend analysis could also be used to compare differences in actual and proposed costs and guide regulatory decisions, for example, in increasing or reducing the utilities' forecast expenditures.

[87] Items to forecasts include load growth, energy growth, depreciation, number of customers, cost of capital, operating expenditure, capital expenditure, and tax expenditure, to name a few.

[88] In UK, Ofgem developed an innovative mechanism called the menu approach or the information quality incentive to address forecasting challenges in capex and opex. This mechanism provides an incentive to utilities to present reasonable estimates of their true investment needs and penalize them if the information is misleading. It allows utilities to choose an implicit "regulatory contract" that provides the best incentive to declare the most accurate investment plans. In addition, it rewards utilities with lower expenditure forecasts and provides for utilities with higher expenditure forecasts to beat the targets by spending less.

Overall, key success factors in PBR implementation in jurisdictions that have adopted this regime since the 1990s [such as the United Kingdom ("UK") and Australia] include:

- PBR design's adaptability to changing environment;
- provision of incentives to encourage cost efficiency and quality of service;
- presence of clearly defined and efficient planning process for network investments; and
- adoption of a clear framework that supports funding of capital expenditure through rates.

Further details regarding jurisdictions that have adopted PBR are in Tasks 2.1.1 (Introduction to the Regulatory Models) and 2.2.2 (Case Studies).

7.1.2 Impact on the roles and responsibilities of the Commission

Under this new regulatory model, the value chain would remain the same, where the incumbent vertically-integrated utilities would continue to own and operate generation, transmission, and distribution assets. However, the PUC would have additional oversight under the PBR model. More specifically, the Commission would be responsible for administering implementation of the PBR model. PBR oversight includes, but is not limited to, the following:

- identifying the performance indicators that would be used to measure the following: (i) cost control; (ii) efficient investment; (iii) "rapid" integration of renewables; and (iv) timely execution of competitive procurement;
- determining the targets that utilities need to achieve for each of the aforementioned metrics;
- in the case of the Outcomes-based PBR, determining the desired outcomes that the utilities are expected to achieve;
- setting up rewards and penalties for achieving or missing targets;
- if needed, designing necessary incentives that drive innovative approaches from the utility;
- reviewing the PBR plan that the utilities submit and ensuring that forecasted costs are reasonable; and
- reviewing utilities' performance (financial and operations) to ensure that they have achieved the outcomes and/or targets set and approved revenues were prudently spent.

Despite this increased responsibility, PBR regimes are typically expected to lead to an overall reduction in the regulatory burden in the long term, primarily due to a lower frequency of regulatory proceedings (when compared to markets under a COS approach) and a less fastidious

review of costs.[89] As such, reduced regulatory costs under a PBR are a result of PBR's recognition of the information asymmetry between the regulator and the utility. Under the COS regime, regulators spend a considerable amount of time and expense to bridge the information gap. Conversely, PBR does not try to rectify this information gap. For example, under a PBR regime (that is designed correctly), the regulator does not need to know the costs for each O&M item but rather the range of possible costs from which the regulator could approve a PBR plan—particularly one that could elicit maximum efficiency from the utility.[90]

Moreover, the PBR also relieves regulators from the demanding task of micro-managing utilities' activities. For utilities, this means they could respond more quickly to technological and competitive challenges and, for customers, this leads to lower prices in the long term.

While these changes would not result in additional infrastructure for the Commission, the change in responsibilities may lead to a change in amount of work, thereby resulting to more staffing. Conversely, the changes in the Commission's role may simply alter the nature of the work itself.

7.1.3 Impact on the roles and responsibilities of utilities

As previously mentioned, the PBR model itself would not change the electric power value chain or structure (unless implemented together with other regulatory frameworks, as described in the hybrid models introduced in Task 2.2.1). However, incentives for utilities would certainly be changed under the PBR model. Vertically-integrated utilities such as the HECO Companies would need to address issues concerning all three functions (generation, transmission, and distribution), including but not limited to, the following:[91]

- Preventing plants from becoming stranded assets;
- Ensuring wires are used in the most efficient way (an issue with renewable generation because renewable sites are not typically located in proximity to major transmission wires); and
- Distributing power such that sales volume, thus, revenues, are growing despite increasing DER adoption levels.

Nonetheless, the PBR's overall stronger advantages lie in its ability to facilitate increasingly efficient operations and deeper attention to quality definition and performance standards. As such, the Commission would also require extensive reporting by the utilities based on performance metrics identified under the model. The Project Team notes that the above areas of

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[89] Sappington, David, Johannes Pfeifenberger, Philip Hanser, and Gregory Basheda. "The State of Performance-Based Regulation in the US Electric Utility Industry." *The Electricity Journal*. October 2001.

[90] Comnes, G.A. S. Stoft, Green, and L.J, Hill. *Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource Planning Issues Volume I*. November 1995. P. 6.

[91] National Renewable Energy Laboratory. *Next-Generation Performance-Based Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation*. September 2017. Page 31.

concern are in line with the need to measure utility performance in the proposed PBR framework for the State of Hawaii. Meanwhile, Hawaii currently has PIMs in place, where rewards or penalties are imposed if targets are met/not met by the vertically-integrated utilities.

7.1.4 Compliance with the reliability, adequacy, and quality of service standards

PBR offers many potential benefits, one of which is its ability to help utilities comply with reliability, adequacy, and quality of service standards established by the PUC over the short- and long-term. Reliability and quality of service could be safeguarded under a PBR regime, especially for plans that have mandated PIMs. More specifically, the implementation of PBR could provide strong incentives for utilities to increase performance and improve productivity because it allows them to derive significant financial benefit from doing so.[92] This benefit is precisely the incentive that motivates utilities in competitive markets to control costs and deliver exceptional service to their customers.

The experiences of some jurisdictions that have implemented PBR illustrate its beneficial role in encouraging productivity improvements. For instance, in the case of FortisBC, the British Columbia Utilities Commission noted: "*the Commission Panel is satisfied that there were positive results experienced by both ratepayers and the shareholder over the PBR period. In addition, the Panel finds there is sufficient evidence to suggest that introducing a PBR environment has the potential to act as an incentive to create productivity improvements*."[93] Moreover, during the 2004-2009 period, FortisBC "*exceeded the O&M targets by an aggregate amount of $87 million over the six years. Customers received 50 percent of this or $43.5 million back via the ESM.*"[94] The O&M savings during FortisBC's PBR period benefited customers in two ways: (i) reduced rates during the term of the PBR via the ESM; and (ii) rebasing of the savings into opening O&M as the starting point in the setting of rates after the PBR has ended.

Another example is in the UK, where the Office of Gas and Electricity Markets ("Ofgem") stated that the RPI-X regulatory framework has brought benefits to electricity customers over the last 20 years and has "*delivered increased capacity and investment, greater operating efficiency, higher reliability, and lower prices.*"[95] In fact, "*since privatization, allowed revenues have declined by 60% in electricity distribution and 30% in electricity transmission. These reductions have been achieved without sacrificing capital investment, which has continued across all sectors since privatization.*"[96] Ofgem also believed that the implementation of PBR "*led to significant improvements in quality of service.*

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[92] Sappington, David, Johannes Pfeifenberger, Philip Hanser, and Gregory Basheda. "The State of Performance-Based Regulation in the US Electric Utility Industry." *The Electricity Journal*. October 2001.

[93] British Columbia Utilities Commission. *Commission Order G-44-12*. Reasons for Decision, page 22.

[94] Ibid.

[95] Ofgem. *Regulating Energy Network for the Future: RPI-X@20 Emerging Thinking*. January 20, 2010. P. 50.

[96] Ibid.

Between 1990 and 2009, the number and duration of reported outages fell by around 30 percent."[97] With that in mind, the implementation of PBR in the State of Hawaii would likely improve the utilities' compliance with the standards set forth by the PUC as well as the quality of service delivered by the system.

7.1.5 Ability to achieve State energy goals

The PBR model is considered to be the most favorable in achieving the State's RPS targets. Under a PBR model, the PUC could set incentives and penalties based specifically on progress towards pre-established goals such as rapid integration of renewables (including third-party home solar and storage systems), affordable rates, electric reliability, and customer choice and satisfaction (Specific PBR metrics could be set for any and all of these criteria.) It enables a "carrot and stick" approach that could be designed to both encourage utilities achieve target performance and penalize them for underperformance. In addition, it provides the utility freedom in optimizing its resources given targets and objectives.

7.2 Financial feasibility

7.2.1 Financial requirements for implementation

Implementation of the PBR regulatory model requires a number of important steps, which have financial implications to the Commission and utilities. These include data collection, regulatory process and timing, stakeholder engagement, and certain changes to the utility's operations—particularly for those that can help ensure achievement of the performance standards. Moreover, utilities and the regulator may hire economic consultants who could advise them on putting together the PBR plan (on the side of utilities) and reviewing the filings (on the side of regulator). This means additional regulatory costs for both the utilities and the PUC.

While timing of the proceedings remains within the purview of the Commission, PBR proceedings tend to be longer than COS cases. This is because PBR proceedings involve additional discussion and analysis of technical issues such as those related to productivity trends, inflation factor, and rewards and/or penalties for performance standards.

Based on the experiences of jurisdictions such as Alberta, Ontario, Australia, and UK, the regulatory process has been observed to be longer under PBR, usually requiring 17 to 32 months, compared to the 12 to 18 months for a COS regulatory process. The experiences of these jurisdictions are illustrated in Figure 7. The PBR process and timing are usually shaped by the number of utilities and interveners that participate in the regulatory process, PBR framework that the jurisdiction is using (whether it is the indexing approach or building blocks approach), and the generation that the regulatory model is in. Proceedings may take longer in the first generation than in subsequent ones.

[97] Ibid.

Figure 7. Process and Timing in PBR (Selected Jurisdictions)

	Alberta	Ontario	Australia	UK
Framework	I-X approach	I-X approach	Building blocks approach	RIIO model
Generation of model	2nd	4th	4th	6th
Number of electric distribution utilities	4	70	13	14
Process	Involves information requests and responses, oral hearings, and rebuttal	Involves information requests and response, oral hearings, and rebuttal	"Propose-respond" model	"Propose-respond" model
Process name	PBR application	Incentive Rate Mechanism ("IRM")	Price determination	RIIO-ED1
Timing	33 months	17 months	19 months	32 months

Source: Alberta Utilities Commission, Ontario Energy Board, Australia Energy Regulator, and Ofgem

At the same time, there is no required investment in enabling technology or software or the creation of new regulatory institutions in implementing PBR. For the utility, it would be useful but not necessary to have a collaboration and document management systems that could help it track, manage, and store documents related to the PBR filings. As discussed earlier, data availability is important under PBR and having a system to do this would be useful to the utility in the long-run. Existing Commission staff and infrastructure could be sufficient to enable the transition to this regulatory model and could be supplemented by additional staff (or consultants) who could help facilitate the stakeholder engagement efforts.

7.2.2 Financial impact on the Commission, utilities, and ratepayers

A well-designed PBR offers many potential benefits to regulators, utilities, and customers. These benefits include superior performance incentives, improved rate predictability,[98]timely consumer benefits, lower administrative/regulatory costs (in the long run), and greater compatibility with a rapidly changing industry. For the utility and the ratepayers, the financial impact of the implementation of a PBR regulatory model is dependent largely on the design of the PBR regime.

When designing a PBR regime, careful consideration in deciding the individual components of the PBR formula is required. These components, which could include an inflation factor, productivity factor, earning sharing mechanism, performance standards, and "off-ramp" triggers, among others, need to be viewed as a whole rather than individually. Collectively, the

[98]Olson, Wayne and Caroline Richards. "It's All in the Incentives: Lessons Learned in Implementing Incentive Ratemaking." *The Electricity Journal*: 20-29.

PBR formula needs to follow key principles in ratemaking—for example, the need to ensure financial stability of utilities and safeguard their ability to earn a commercially reasonable rate of return, administrative simplicity, ease of understanding for ratepayers, and alignment of incentives between shareholders and ratepayers. Nevertheless, COS ratemaking principles continue to be relevant under a PBR approach, including those that facilitate the determination of "going in rates."

Often, utilities are concerned that their financial viability may be undermined if there would be substantial capex requirements (which are not usually recognized in a timely manner in the PBR indexation formula) or if actual conditions depart from "test year" or historical conditions. Some regulators have addressed this issue by prescribing forward capital planning. Regulators are also dealing with such challenges through capex incentive mechanisms[99] although such mechanisms complicate the administration of the PBR regime. Other jurisdictions have incorporated adjustment factors within the PBR formula to address capital cost issues or have modified the PBR design, so the treatment of the capex becomes a cross between COS and "comprehensive" forms of PBR.

The targets set for efficiency and productivity need to be balanced against the financial viability of the utility and consideration of costs that are within management's control. This benefit is precisely the incentive that motivates utilities in competitive markets to control costs and deliver exceptional service to their customers. As detailed in Section 7.1.4, the experiences of some jurisdictions that have implemented PBR illustrate its beneficial role in encouraging productivity improvements.

7.3 Legal feasibility

7.3.1 Hawaii Ratepayer Protection Act

The Hawaii Ratepayer Protection Act, which essentially mandates a form of PBR in Hawaii, was signed into law on April 24, 2018 and took effect on July 1, 2018.[100] This new law seeks to address concerns that the traditional regulatory approach does not provide appropriate incentives to utilities, so they could meet the challenges of a renewable and distributed energy future.[101]

There is a need to update the regulatory framework, so the State can align the utilities' financial interests with public interest. The Legislature was "*concerned that the existing regulatory compact misaligns the interests of customers and utilities because it may result in a bias toward expending utility*

[99] An example of a capex incentive mechanism is the efficiency carryover scheme ("ECS") that is being implemented in Australia and the Philippines. An ECS encourages prudent and efficient capex spending and shares the benefits of capital efficiencies with the customers.

[100] Gov. Msg. No. 1105 (April 24, 2018); *see also* 2018 Haw. Sess. Laws Act 5.

[101] *Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5, § 1.

capital on utility-owned projects that may displace more efficient or cost-effective options, such as distributed energy resources owned by customers or projects implemented by independent third parties."[102]

The Legislature explained that the purpose of the Ratepayer Protection Act is "*to protect consumers by proactively ensuring that the existing utility business and regulatory model will be updated for the twenty-first century by requiring that electric utility rates be considered just and reasonable only if the rates are derived from a performance-based model for determining utility revenues*."[103]

The law further directs the PUC to create "*performance incentives and penalty mechanisms that … break the direct link between allowed revenues and investment levels*" by January 1, 2020.[104] The performance incentives and penalty mechanisms are expected to be applied through the PUC's regulation of electric utility rates under HRS § 269-16.[105]

In developing performance incentives and penalty mechanisms, the Hawaii Ratepayer Protection Act requires the PUC to consider economic incentives, penalties, and cost-recovery rules that promote affordability of rates, electric reliability, customer choice and satisfaction, data transparency, rapid integration of renewables, and timely execution of competitive procurement and other business processes.[106] Note that the Ratepayer Protection Act specifically exempts member-owned cooperative electric utilities such as Kauai Island Utility Cooperative ("KIUC").[107]

7.3.2 PBR Docket 2018-0088

On April 18, 2018, the PUC issued Order No. 35411, *Instituting a Proceeding to Investigate Performance-Based Regulation*, on April 18, 2018, opening Docket No. 2018-0088 ("Order 35411"), a proceeding that would investigate the PBR for the HECO Companies ("PBR Docket").[108] The PUC intends for the PBR Docket to be "*a forum by which to evaluate the current regulatory environment; identify which elements, if any, may not adequately align with the public interest; and collaboratively develop modifications or new components to better align utility and customer interests*."[109] The PUC seeks to "*(1) identify specific areas of utility performance that should be improved; (2) determine*

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[102] *Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5, § 1.

[103] *Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5, § 1. (Emphasis added.)

[104] *Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5, § 3. (Emphasis added.)

[105] *Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5, § 3. *See* § 269-16. Regulation of utility rates; ratemaking procedures.

[106] *Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5.

[107] *Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5, § 3.

[108] Order No. 35411.

[109] Order No. 35411, at 51.

appropriate metrics for measuring successful outcomes in those areas; and (3) establish reasonable financial rewards and/or penalties that are sufficient to incent the utility to achieve those outcomes."[110]

The PUC explained that PBR includes a "*set of alternative frameworks and regulatory mechanisms intended to focus utilities on performance and desired outcomes as opposed to simply growth in capital investments or other determinants of utilities earnings*" under traditional COS rate regulation.[111] PBR offers regulators a way to restructure utility financial incentives to achieve broad objectives such as incentivizing cost reduction and achievement of policy goals, improving unsatisfactory performance, integrating technological advances, and supporting customer choice.[112]

The current regulatory framework implemented by the PUC under its existing authority already includes

> "*in at least some form, several of the fundamental components ordinarily associated with PBR, including [a Multi-Year Rate Plan] (fixed three-year cycle for general rate cases), an interim-period revenue adjustment mechanism subject to a revenue cap, a revenue decoupling mechanism, and an [Earnings Sharing Mechanism]. In addition, several [Performance Incentive Mechanisms] are already in place, and others are actively being contemplated, including [Performance Incentive Mechanisms] rewarding successful implementation of new renewable programs and procurement of utility-scale renewable generation*."[113]

In the PBR Docket, the PUC stated that it is particularly interested in PBR mechanisms that result in:

- "*Greater cost control and reduced rate volatility;*
- *Efficient investment and allocation of resources regardless of classification as capital or operating expenses;*
- *Fair distribution of risks between utilities and customers; and*
- *Fulfillment of state policy goals*." [114]

The PBR Docket proceeding will be implemented in two phases:

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[110] Order No. 35411, at 52.

[111] Order No. 35411, at 13.

[112] Order No. 35411, at 14.

[113] Order No. 35411, at 40-41. (Footnotes omitted.)

[114] Order No. 35411, at 5.

- In Phase 1, the current regulatory framework will be assessed and evaluated. Specific areas of utility performance that should be targeted for improvement and metrics for determining successful outcomes in those areas will be identified. [115]

- In Phase 2, the PUC will focus on refinements and modifications that can be made to the existing regulatory framework in order to incentivize the utility to achieve those outcomes. New PBR frameworks (including those for performance incentives and increasing the alignment between utilities' and customers' interests) will be developed. [116]

The Commission expects Phase 1 to conclude in "*approximately nine months*" while Phase 2 will take approximately 12 months.[117]

Under Order No. 35411, the PUC excused KIUC from involvement in Docket No. 2018-0088 because the method used by KIUC in determining rates, which is the Times Interest Earned Ratio approach discussed previously,[118] is "*unlikely to present the same potential risks to KIUC's customers as compared to those present for customers of for-profit*."[119]

7.3.3 Existing legal framework for the regulatory model

There is no comprehensive PBR legal framework yet. However, as described above, the legal framework for the establishment of the PBR model in Hawaii is currently under development pursuant to the requirements of the Ratepayer Protection Act and by the PUC in the PBR Docket. The Ratepayer Protection Act, as discussed above, requires the PUC to "*establish performance incentives and penalty mechanisms that directly tie an electric utility's revenues to that utility's achievement on performance metrics and break the direct link between allowed revenues and investment levels*" by January 1, 2020.[120] The PUC expects to conclude both phases of the PBR Docket in approximately 21 months.[121]

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[115] Order No. 35411, at 53.

[116] Order No. 35411, at 55.

[117] Order No. 35411, at 55.

[118] *See* Task 2.1.2. – "High-level and general assessment of the existing regulatory model in place in Hawaii," Section 3.4.3.

[119] Order No. 35411, at 9-10.

[120] *See Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5, § 3.

[121] Order No. 35411, at 55. The PBR Proceeding was opened on April 18, 2018.

7.3.4 PUC authority under current legal and regulatory framework

As described above, the current regulatory framework already includes some form or components of PBR.[122] In addition, the PUC opened the PBR Docket proceeding under its existing general investigative authority and Legislative guidance on issues it may consider under HRS §§ 269-6, & -7, even prior to the enactment and effective date of the Ratepayer Protection Act.[123] The Ratepayer Protection Act, as discussed above, establishes the PUC's authority further in implementing PBR consistent with the Ratepayer Protection Act and, in fact, mandates the implementation of PBR as provided in the Ratepayer Protection Act. Accordingly, the PUC's authority to implement the PBR model should be firmly established so long as it is consistent with existing authority, the Ratepayer Protection Act, and any other applicable law.

7.3.5 Statutory changes or laws required for implementation

The Ratepayer Protection Act as described above likely provides sufficient legislative authority and policy direction to the PUC in implementing the PBR model in Hawaii as well as the provisions of the Act itself.

7.3.6 Administrative actions required by the PUC

The PUC must, as discussed above, implement the Ratepayer Protection Act so it can establish performance incentives and penalty mechanisms that will (1) "*directly tie*" the revenues of an electric utility to its achievement of performance metrics (which must be determined), and (2) "*break the direct link*" between the utility's revenues and investments. Moreover, the Ratepayer Protection Act explained that its purpose is to protect consumers by updating the existing utility and regulatory business model, which requires that "*electric utility rates be considered just and reasonable only if the rates are derived from a performance-based model for determining utility revenues*." Furthermore the "*performance incentives and penalty mechanisms…shall apply to the regulation of utility rates under [HRS] section 269-16.*" Therefore, the "*performance incentives and penalty mechanisms*" mandated in the Ratepayer Protection Act must be established administratively by the PUC for the PBR model in Hawaii.

The PUC has, as discussed above, already embarked on an investigative docket proceeding to evaluate the current regulatory environment and develop modifications or new components to better align utility and customer interests, by initiating the PBR Docket. The PUC initiated the PBR Docket pursuant to its general investigative and supervisory authority over public utilities under HRS §§ 269-6, & -7. Although the PUC opened the PBR Docket prior to the enactment and effective date of the Ratepayer Protection Act, the PBR Docket appears to be generally consistent with the intent of the Ratepayer Protection Act and to the extent required, the PUC may adjust the issues that must be considered in the PBR Docket so as to directly satisfy the requirements of the Ratepayer Protection Act.

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[122] Order No. 35411, at 40-41. (Footnotes omitted.)

[123] Order No. 35411, at 6.

Alternatively, the PUC may also exercise its rulemaking authority as an administrative agency that could initiate a rulemaking process following the implementing rules of the Ratepayer Protection Act, as authorized by HRS Chapter 269.[124]

7.3.7 Additional legal issues

The Ratepayer Protection Act, as discussed above, provides that it applies to the regulation of electric utility rates under HRS § 269-16, which is the governing provision in HRS Chapter 269 on public utility ratemaking by the PUC. Under such statute, the PUC is generally required to provide regulated public utilities with an opportunity to earn a fair or reasonable rate of return on property used to provide regulated public utility services.[125]

Similarly, it should be noted that depending on how rates are determined and enforced, rates that are not sufficient to yield a reasonable return on property used for utility services may be determined to be confiscatory and violate certain constitutional requirements."[126]

As mentioned, the Ratepayer Protection Act requires the PUC to establish performance incentives and penalty mechanisms. Functions such as these certainly require legal mandates.

The PUC has already recognized that the PBR model, which would be developed and implemented in Hawaii should continue to provide electric utilities with an opportunity to earn a fair return on its property:

> *PBR includes a set of alternative frameworks and regulatory mechanisms intended to focus utilities on performance and desired outcomes, as opposed to simply growth in capital investments or other determinants of utility earnings under COSR. Well-designed PBR frameworks should result in an incentive structure that encourages exemplary utility*

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[124] *See* HRS § 269-6(a):

> (a) The public utilities commission shall have the general supervision hereinafter set forth over all public utilities and shall perform the duties and exercise the powers imposed or conferred upon it by this chapter. Included among the general powers of the commission is the authority to adopt rules pursuant to chapter 91 necessary for the purposes of this chapter.

[125] HRS § 269-16(b) ("The commission, upon notice to the public utility, may . . . [d]o all things that are necessary and in the exercise of the commission's power and jurisdiction, all of which as so ordered, regulated, fixed, and changed are just and reasonable, and provide a fair return on the property of the utility used and useful for public utility purposes."); *see also* Order No. 35411 ("With the traditional [Cost of Service Regulation] framework, utility rates are set to allow electric utilities a reasonable opportunity to recover the costs incurred to provide general service, including a return on investment. An electric utility realizes earnings through a rate of return on the utility's capital investments, provided the regulator finds those capital investments were just and reasonable."); *cf.* Decision and Order No. 31288, issued in Docket No. 2011-0092, on May 31, 2013, Exhibit C, at 3 ("While a public utility is required to have a reasonable opportunity to earn a fair financial return, attractive financial returns are not an entitlement by virtue of being a regulated utility.").

[126] *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 43 S.Ct. 675, 690 (1923) ("Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.").

> *performance irrespective of the nature of its investments (e.g., investment in capital expenditures verses investment in measures by a non-utility, third party). By providing rewards for specific outcomes and objectives**, a PBR framework should provide a utility with the opportunity to earn fair compensation, based on a business model that is well aligned with the public interest***.[127] [Emphasis added.]

Therefore, the PBR model, which would be developed and implemented in Hawaii should be carefully designed so it could provide the electric utility with an opportunity to earn a fair return on its property.[128]

7.4 Conclusion

The PBR regulatory model has few feasibility risks as compared to the other regulatory models. The challenges faced in implementation are mainly in data collection, stakeholder engagement, and increased regulatory timing. Given that the utility structure remains largely unchanged under this regulatory model, there are no transition risks and need for the creation of new entities. Under these evaluation criteria, this regulatory model is ranked as neutral or low risk (Figure 8).

Figure 8. PBR Model: Feasibility Criteria Summary

Criteria	Categorization	Various Considerations
Technical Feasibility	Implications for role and responsibilities	No change expected given existing PBR rate case
	Compliance with service standards	(+) Incentive mechanisms can be designed to target specific service and quality standards
	Achievement of State clean energy goals	(+) Commission can set incentives and penalties that directly target pre-established goals
Financial Feasibility	Implementation requirements	(-) Data collection, stakeholder engagement and increase in time required
	Impact on ratepayers	(+) Earning sharing mechanisms allow efficiency gains to be shared
	Impact on utilities	(+/-) Depends on the design of the incentives and components of the formula
Legal Feasibility	Existence of supporting legal framework	(-) Current PBR regulatory framework is under development in the PBR docket
	Governance requirements	(+) Provisions exist in the Ratepayer Protection Act but must be implemented by the PUC
	Additional legal factors	(+) Implementation must also take the requirement to provide a reasonable return for utilities into consideration

Source: LEI analysis

[127] Order 35411, at 13-14.

[128] A distinction between existing investments and investments to be made subsequent to implementing a PBR model may also be considered. To the extent that there may be an issue of stranded costs for existing investments, the PUC is statutorily authorized to establish a mechanism that would allow electric utilities to recover stranded costs related to early retirement of fossil fuel generation plants. *See* HRS § 269-6(d)(3).

8 Lighter regulation for cooperatives

As described in Task 1.1.1, cooperatives ("co-ops") are organizations or companies that are effectively owned by their members, who are generally their customers. They are incorporated under the laws of the state in which they operate. In Hawaii, the island of Kauai is served by KIUC. KIUC operates as a co-op utility—meaning, it is owned and governed by its members (who receive services from KIUC) and is not an IOU or owned by a third-party investor.[129] KIUC is regulated by the PUC—an arrangement that is largely unique to Hawaii.

The regulatory models discussed in the earlier sections are not applicable to co-ops, thus, not applicable to KIUC in the State of Hawaii. In this regulatory model proposed by the Project Team and as discussed in Tasks 2.1.1 and 2.2.1, co-ops would be subject to lighter regulation from the PUC and would have some control from the Board of Directors as well as members. Under this Lighter Regulation model, co-ops may be exempted from certain regulations, which were established based on an investor-owned utility ("IOU") structure. These could include PUC regulations for the approval of rate setting and design, power purchase agreements with IPPs, fuel contracts, and large capital expenditures, particularly if such transactions do not exceed a particular threshold. Such thresholds regarding rate increases and capital expenditures would be established to trigger review by the Commission. State energy goals would remain applicable to co-ops.

8.1 Technical feasibility

To facilitate the Lighter Regulation model, the Board of Directors, who are selected as per the by-laws of the co-op, would continue to approve operating and capital budgets, develop plans taking into account the interest of the members, and ensure the adequacy of electricity supply. Co-ops would remain under the regulatory oversight of the Rural Utilities Service ("RUS") in terms of planning, financing and capital investments.[130]

When it comes to the utility's roles and responsibilities, the co-op would retain its existing mandate, which is to ensure reliable and least-cost power for its members and pursue strategies that would help achieve this as directed by its members. Members, through the Board of Directors (and their voting system), are free to decide the level of reliability standards and renewable targets that they desire.

For the regulator, this reduction of regulatory jurisdiction over the co-op would mean it may have less control in ensuring that the co-op's goals align with State energy goals (which are outlined

[129] Order No. 19658, filed in Docket No. 02-0060, on September 17, 2002, at 12.

[130] The RUS is a program under the US Department of Agriculture whose mandate is to administer programs that provide much-needed infrastructure or infrastructure improvements to rural communities. Programs include provision of capital and leadership to maintain, expand, upgrade and modernize their electric infrastructure, loans and loan guarantees finance the construction or improvement of electric facilities and funding to support demand-side management, energy efficiency, and conservation programs. (Source: United States Department of Agriculture. *Rural Utilities Service website.* Accessed at https://www.rd.usda.gov/about-rd/agencies/rural-utilities-service)

in Section 3.1). Therefore, there is no assurance that the co-op would be able to help achieve the State's goals under Lighter Regulation.

Historically in Hawaii, KIUC has maintained renewable energy as one of its strategic priorities and is currently seeking to remain ahead of the State goal of 100% renewable energy by 2045. Its current target is to source 70% of all its electricity by 2030, ahead of the state energy goal of 40% by the same year.[131]

8.2 Financial feasibility

There would be no financial requirements for the co-op nor the utility with the implementation of Lighter Regulation. In fact, there would be additional benefits of reduced costs by not participating in regulatory dockets and regulatory compliance. For the existing co-ops, regulatory as well as fees paid to the PUC costs would decline, the saved funds potentially remaining with would remain with them. For customers, the decline in regulatory costs may translate to lower costs.

8.3 Legal feasibility

Under the Lighter Regulation for co-ops model (which would apply to KIUC only), the regulatory framework would be customized substantially to reduce regulation of KIUC as a public utility.

8.3.1 Existing legal framework for the regulatory model

Currently, KIUC continues to be overseen by the PUC—similar to the HECO Companies and unlike most cases of co-ops on the mainland. Due to concerns of what may occur if KIUC were to be deregulated, the co-op agreed not to seek complete regulatory exemptions from the PUC or support legislation deregulating its services until January 2008.[132] Since then, generally, KIUC has still been regulated by the PUC, which has statutory authority to do so.[133]

However, the regulation of KIUC has been relaxed in certain aspects. For example, KIUC is not required to undergo the Power Supply Improvement Process or the Distributed Generation Interconnection Plan, unlike the HECO Companies.[134] Moreover, the PUC approved KIUC's exemption from the Competitive Bidding Framework that governs the procurement process of

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[131] Kauai Island Electricity Cooperative. *Clean Energy*. Accessed at: <http://kiuc.coopwebbuilder2.com/content/clean-energy>

[132] Stipulation in Lieu of Preliminary Position Statements, filed in Docket No 02-0060, on July 18, 2002 at 30 ("KIUC will not petition the Commission nor seek or support any legislation that would have the effect of reducing or eliminating any element of existing Commission jurisdiction over KIUC through at least December 31, 2007").

[133] HRS § 269-31(b).

[134] KIUC's Final Statement of Position, filed in Docket No. 2014-0192, on June 29, 2015 at n.1 at 2; *See* Order No. 32269, filed in Docket No. 2014-0192, on August 21, 2014, at n. 8 at 6. *See also* Order No. 32257, filed in Docket No. 2014-0183 on August 7, 2014 at 1.

the HECO Companies.[135] Furthermore, the PUC will often open dockets on specific items focusing solely on the HECO Companies such as the PUC docket proceeding on Grid Modernization.[136] Most recently, as discussed above, KIUC is exempted from the requirements of the Ratepayer Protection Act and the PBR Docket. However, KIUC is required, on occasion, to participate in certain dockets opened by the PUC. For example, KIUC was made part of the Community Based Renewable Energy Program docket[137] and also required to participate in the Distributed Energy Resources docket.[138]

Similarly, the PUC may on its own motion or upon request issue a declaratory order to address a controversy or remove uncertainty in rules in order to determine how public utility laws and rules should be applied (or not applied) to KIUC.[139] More specifically, under existing law, the PUC is authorized to waive or exempt an electric co-op from requirements under HRS Chapter 269 or any PUC rules or orders under certain circumstance:

> *"Notwithstanding any provision of this chapter or any franchise, charter, law, decision, order, or rule to the contrary, the public utilities commission, sua sponte or upon the application of an electric cooperative, may waive or exempt an electric cooperative from any or all requirements of this chapter or any applicable franchise, charter, decision, order, rule, or other law upon a determination or demonstration that such requirement or requirements should not be applied to an electric cooperative or are otherwise unjust, unreasonable, or not in the public interest. Notwithstanding the above, the public utilities commission and the consumer advocate shall at all times consider the ownership structure and interests of an electric cooperative in determining the scope and need for any regulatory oversight or requirements over such electric cooperative."*[140]

Therefore, under HRS § 269-31(b), PUC may waive or exempt KIUC from specific regulatory requirements. Theoretically, KIUC could submit an application to the PUC under HRS § 269-31(b) to waive some or all of any applicable regulatory requirements particularly that the time period allowed for KIUC's stipulation that it would not seek deregulation has already passed as

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[135] Order No. 23298 Instituting a Proceeding to Investigate Competitive Bidding for New Generating Capacity in Hawaii, filed in Docket No 03-0372, on March 14, 2007.

[136] Docket No. 2017-0226.

[137] Order No. 33268, filed as a Letter Notice, on October 21, 2015 at 1; *See* Order No. 32269, filed in Docket No. 2014-0192, on August 21, 2014 at 1; *See* Order No. 33747, filed in Docket No. 2015-0382, on June 7, 2015; *See also* KIUC's Comments to the Proposed Statewide CBRE Program, filed in Docket No. 2015-0389, on March 1, 2017.

[138] Order No. 32269, filed in Docket No. 2014-0192, on August 21, 2014 at 1.

[139] HAR § 6-61-160.

[140] HRS § 269-31(b).

of January 1, 2008.[141] However, HRS § 269-31(b) does not expressly authorize the PUC to amend or revise any regulatory requirements for that may be applicable to electric co-ops such as KIUC.

8.3.2 PUC authority under current legal and regulatory framework

Although there is an existing legal framework (both statutory and case law authority) that would allow the PUC to waive or exempt electric co-ops from any and all regulatory requirements (i.e., for KIUC to be deregulated),[142] there is currently no authority for the PUC to otherwise revise or customize regulatory requirements for electric co-ops that are unique from the regulation of IOUs under a Lighter Regulation model.

8.3.3 Statutory changes or laws required for implementation

Assuming that the intent is to customize regulatory requirements that are applicable to electric co-ops (in addition to simply waiving or exempting electric co-ops from certain or all regulatory requirements), the State Legislature would need to either customize any statutory laws for electric co-ops or authorize the PUC to do so.

8.3.4 Administrative actions required by the PUC

To further implement the Lighter Regulation model for electric co-ops, the PUC could waive or exempt KIUC from any or all applicable laws or regulations pursuant to its authority under HRS § 269-31(b).

As discussed above, if the intent is to customize regulatory requirements that are applicable to co-ops (in addition to simply waiving or exempting them from certain or all regulatory requirements), and if the State Legislature authorizes the PUC to do so with any such further legislation, the latter would then be required to proceed with customizing any statutory regulatory requirements for electric co-ops.

8.3.5 Additional legal issues

Other than the legal issues described above, there appears to be no other significant legal issues at this time.

8.4 Conclusion

The Lighter Regulation model has few financial risks as well as technical risks for implementation. However, the benefits gained from reduced regulatory costs and compliance because of independence from or reduced dependence on the PUC may be lost from weaker oversight and potential mediation during board-member disputes. That being said, given the existing legal framework for co-ops in adopting the Lighter Regulation and the PUC's authority to relieve co-ops from regulatory requirements, the Lighter Regulation model for co-ops presents

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[141] Stipulation in Lieu of Preliminary Position Statements, filed in Docket No. 02-0060, on July 18, 2002 at 30 and 32.

[142] HRS § 269-31(b); HAR §§ 6-61-159, 160.

little legal barriers. In consideration of this, the Lighter Regulation model ranks as neutral in terms of overall feasibility (Figure 9).

Figure 9. Lighter Regulation Model: Feasibility Criteria Summary

Criteria	Categorization	Various Considerations
Technical Feasibility	Implications for role and responsibilities	No change expected
	Compliance with service standards	(-) Reduced oversight from PUC may lead to less stringent compliance to service standards
	Achievement of State clean energy goals	(-) Lack of PUC oversight may hamper direction to achieve state goals
Financial Feasibility	Implementation requirements	No change expected
	Impact on ratepayers	(+/-) Lower costs may be offset by reduced oversight
	Impact on utilities	(+) Reduced regulatory compliance costs
Legal Feasibility	Existence of supporting legal framework	(+) Legal framework exists to support the waiving or exemption of co-ops from regulatory requirements
	Governance requirements	(-) State Legislature would need to customize statutory laws for co-ops or authorize the PUC to do so
	Additional legal factors	No additional significant legal issues

Source: LEI analysis

9 Conclusions

In assessing the technical, financial, and legal feasibility of each of the proposed models, namely, status quo, HERA model, IGO, distribution-focused (i.e., DSPP model), PBR, and Lighter Regulation for co-ops, the LEI team noted a number of emerging themes from this high-level and preliminary analysis:

- ***More complex regulatory models require greater changes in roles for the commission and utilities***: a review of each regulatory model suggests that the greater the technical complexity of the model, the more significant the changes in roles for the commission and utilities are. For instance, the models involving competitive markets, i.e., IGO and distribution-focused models would require substantial changes in the role of the commission especially as it transitions to oversight of competition;

- ***Transition/implementation costs are an essential factor in considering all models:*** in each model reviewed, the financial implications to the Commission, utilities, and ratepayers are linked strongly to the necessary transition costs for implementation. For the market-based models, i.e., IGO and DSPP models, careful market design and consumer education are critical success factors. For models that maintain existing utility structures, i.e., HERA and PBR, transition costs are linked to the creation and strengthening of existing institutions that would implement the respective models;

- ***Need for additional legislative processes:*** for IGO and DSSP models, the legal feasibility analysis suggests that other legislative processes would be needed to provide the necessary mandate, so the Commission could initiate these models. An assessment of the provisions given in the Ratepayer Protection Act may limit the full implementation of these models;

- ***Achievement of state clean energy goals is feasible in all models:*** the feasibility analysis suggests that achievement of the Hawaii state goal for 100% renewable energy is possible in all models provided there is careful market or incentive design.

Within the context of Hawaii, the LEI team introduced combinations of some of the regulatory models (Task 2.2.1), which may address a number of the feasibility issues that arise from each of these models. For instance, the HERA model may be paired with PBR so there would be an oversight on reliability issues. In this model, the HERA body is designed as an ombudsman that could focus on interconnection and monitoring reliability standards. The other combination is the hybrid model, which involves DSPP and IGO with Outcomes-based PBR, where the utilities function as a platform provider and an independent entity manages the dispatch and planning of the wires assets and the rates are determined based on the utilities' performance targets.

10 Appendix A: Scope of work to which this deliverable responds

2.2.3 High level assessment of the technical, financial, and legal feasibility of each regulatory model. CONTRACTOR shall provide a high-level assessment of the technical, financial, and legal feasibility of each regulatory model.

DELIVERABLE FOR TASK 2.2.3. CONTRACTOR shall provide its conclusions and all work related to technical, financial, and legal feasibility of each regulatory model. CONTRACTOR shall include any existing challenges with Hawaii statutes or regulations in terms of the regulatory model; technical issues from work conducted in TASKS 2.1 and 2.2.1 and financial feasibility analysis from TASK 2.2.2. The CONTRACTOR shall provide a summary of analysis and conclusions of this research in MS Word and PowerPoint. CONTRACTOR shall submit deliverable for TASK 2.2.3 to the STATE for approval.

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Estimating potential stranded costs resulting from a change in regulatory model in Hawaii

working paper prepared by London Economics International LLC for the State of Hawaii with support from Meister Consultants Group

June 12th, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group ("the Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State of Hawaii in achieving its energy goals. As part of the engagement, this memo discusses an estimate for stranded costs that may result from a change in regulatory model for utilities in the State of Hawaii. As detailed in previous working papers, stranded costs are costs that utilities can recover through their rates but whose recovery may be hindered or averted due to competition in the industry or forced divestiture. In general, not all changes in regulatory model would result in stranded costs that then have to be recovered from ratepayers. The Project Team shows that regulatory models that introduce market-based constructs result in the potential for stranded costs for utility generation assets that range between $11 million and $32 million for HELCO, MECO, and KIUC and could surpass $300 million for HECO.

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List of acronyms

CMVE	Competitive Market Value Estimate
Co-op	Cooperative utility
DBEDT	Hawaii Department of Business, Economic Development, and Tourism
DER	Distributed Energy Resource
DSPP	Distributed System Platform Providers
FERC	Federal Energy Regulatory Commission
HECO	Hawaiian Electric Company, Inc.
HEI	Hawaiian Electric Industries, Inc.
HELCO	Hawaii Electric Light Company, Inc.
HERA	Hawaii Electricity Reliability Administrator
HSEO	Hawaii State Energy Office
IDER	Integrated DER
IDSO	Independent Distribution System Operator
IOU	Investor-Owned Utility
IPP	Independent Power Producer
IRP	Integrated Resource Plan
ISO	Independent System Operator
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company, Ltd.
Munis	Municipal utilities
MW	Megawatt
PBR	Performance-based Regulation
PPA	Power Purchase Agreements
PSIP	Power Supply Improvement Plan
PUC	Public Utilities Commission
SCO	Stranded Cost Obligation
SGS	Schofield Generating Station
SPV	Special Purpose Vehicle

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1 Executive summary

London Economics International LLC, together with Meister Consultants Group (the "Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which corresponds to Task 2.2.4 in the project scope of work, provides a discussion of the potential for stranded costs following a change in regulatory model for the utilities serving electric customers in Hawaii.

In a previous working paper discussing potential ownership models for the utilities serving Hawaii's counties (Task 2.1.1.),[1] the Project Team introduced four potential utility regulatory models, namely:

- status quo (cost of service) with/without increased oversight;
- independent system operator ("ISO");
- distribution-focused regulatory model – Integrated Distributed Energy Resources ("IDER") operator; and
- performance-based regulation model ("PBR").

What matters most for the discussion on stranded costs is whether the utility assets, which are currently regulated and on which the utilities are allowed to earn a return on their investment, would remain under such a regulated scheme or rather would become "merchant" assets; in other words, the owner of such assets would earn a return equal to what the market can provide.

This distinction can be done along the line of functional classes of assets (generation, transmission, distribution, other) and will vary according to the regulatory model. For instance, the Project Team expects that generation assets would become unregulated under the ISO or IDER models, whereas in all other cases the utility assets would remain regulated.

In the case of models where assets remain regulated (status quo and PBR), there would not be stranded costs related to the change in regulatory regime since the utility assets, or rate base assets, have been procured under the oversight of the Public Utilities Commission ("PUC") and thus can be presumed to be reasonable and necessary to the continued reliable operation of the power grid in each county.[2]

Should a change in regulatory model require the transfer or divestment of certain classes of utility assets, the transfer price would presumably follow a competitive process where multiple interested parties would bid to purchase either part of or the entire portfolio of utility assets that are being divested. If the assets become unregulated, or "merchant," the acquiring entity will

[1] Task 2.1.1. Review of potential regulatory models that could be applied in Hawaii.

[2] There may be stranded costs at the time the assets are retired if not fully depreciated, but they would not be caused by the change in regulatory regime but rather by evolution of generation resource mix.

purchase the assets at a price that allows it to cover its costs and earn their desired return on investment, based on the expected magnitude of market revenues. As discussed in Task 1.1.6., stranded costs arise if the market value of assets the utilities must divest, such as generation resources, is lower than their book value. Historically, provided that the investments were prudent and verifiable, utilities have been allowed to recover stranded costs from ratepayers.

The Project Team estimated the potential stranded costs for utility production assets in the State of Hawaii as illustrated in Figure 1. All options considered by the Project Team assume that transmission and distribution assets would remain regulated and as such would not be a source of stranded costs for the incumbent utilities should there be a change in regulatory regime.

Figure 1. Potential stranded costs for utility production assets in the State of Hawaii

Utility	Potential production assets stranded costs
HECO	$321.9 million
HELCO	$12.5 million
MECO	$11.3 million
KIUC	$31.9 million

Source: Project Team

The Project Team's estimates of stranded costs are based on several assumptions which are intended to provide a base case to estimate stranded costs. In reality, the actual magnitude of stranded costs may differ due to a variety of factors, such as:

1. market risk vs. regulatory certainty for acquiring entity;
2. higher cost of equity for merchant entities than regulated ones;
3. potential buyers having more bearish views on market conditions; and
4. single asset vs. portfolio purchase.

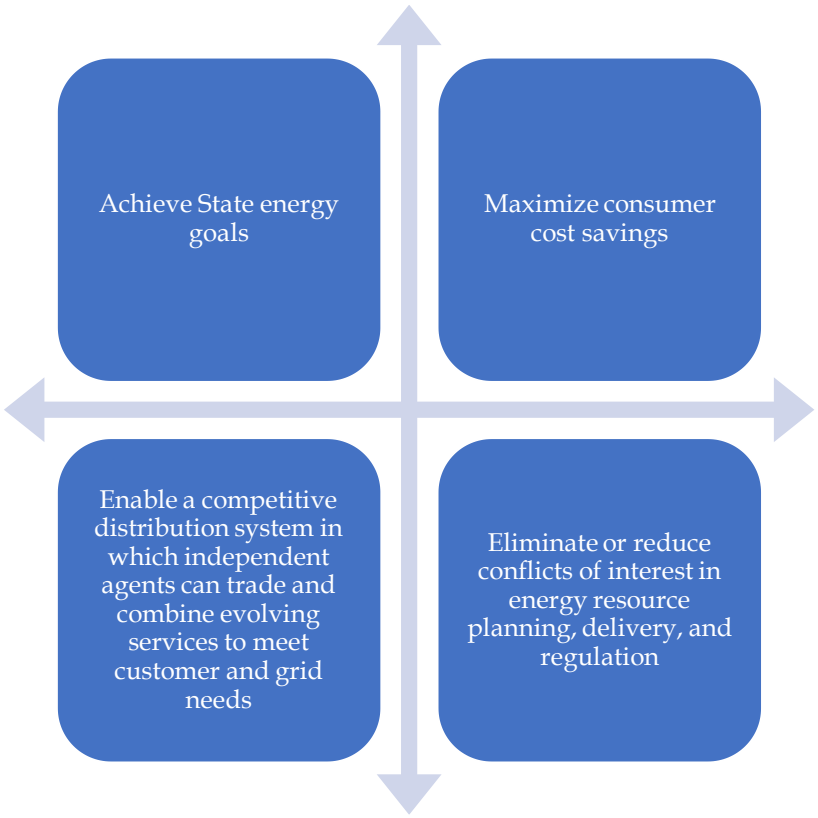
2 Introduction and scope

2.1 Project description

DBEDT was directed by the State's legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. The Project Team, through a competitive sealed proposals procurement,[3] was contracted to perform this study.[4]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[5] listed in Figure 2.

Figure 2. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595.

[3] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[4] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[5] House Bill No. 1700 Relating to the State Budget.

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[6]

2.2 Role of this deliverable relative to others in the project

This deliverable corresponds to Task 2.2.4. in the project scope of work. It builds on previous deliverables to discuss the potential for stranded costs related to the various ownership models introduced in the report for Task 1.1.1./Task 1.2.1. and the detailed discussion provided in Task 1.1.6., given the current regulated assets of the incumbent utilities. As noted by the team in previous working papers, an assessment of utility ownership models cannot be considered in isolation from the regulatory framework in which they are embedded. A discussion of potential stranded costs in different regulatory environments is the topic of this deliverable.

2.3 Future refinements

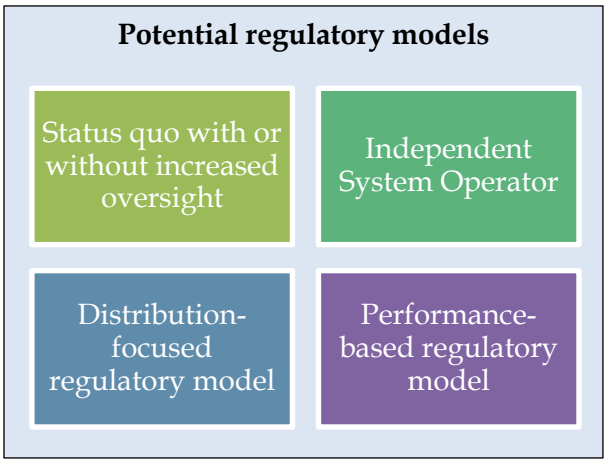
This deliverable includes a discussion of the potential for stranded costs for the various regulatory introduced in the report for Task 2.1.1. Since the results of the Project Team's analysis discussed in the previous deliverable are subject to further refinement and change as the project moves forward and inputs from the stakeholder groups and results of the quantitative analysis and case studies become available, the Project Team may make further refinements to the current report.

[6] Hawaii Contract No. 65595. Scope of Services.

3 Potential stranded costs for various regulatory models

In a previous working paper discussing potential regulatory models for the utilities serving Hawaii's counties (Task 2.1.1.),[7] the Project Team introduced four potential utility regulatory models, namely:

- status quo (cost of service or "COS") with/without increased oversight;
- independent system operator ("ISO");
- distribution-focused regulatory model ("IDER"); and
- performance-based regulation ("PBR") model.



Although there can be significant variations within each regulatory model, the Project Team attempted to present each in a way that encompasses the most common forms.

The various regulatory models discussed range from the traditional (cost of service, performance-based regulation, or independent system operator) to other novel models such as a distribution-focused regulatory model. However, what matters for the discussion on stranded costs is whether the utility assets, which are currently regulated and on which the utilities are allowed to earn a return on their investment, would remain under such a regulated scheme or rather would become "merchant" assets – or, said another way, whether the owner of such assets would earn a return equal to what the market can provide.

This distinction can be made along the line of functional classes of assets (generation, transmission, distribution, other) and will vary according to the regulatory model. For instance, the Project Team expects that generation assets would become unregulated under the ISO or IDER models, whereas in all other cases the utility assets would remain regulated.

3.1 Regulatory models where assets remain regulated

Among the regulatory models that are being analyzed as part of this project, the Project Team discussed two ratemaking models, COS and PBR, that can be considered as traditional in the sense that operations are mostly conducted in a traditional manner, where generation, transmission, and distribution functions are conducted or coordinated by a single entity. Under those regulatory regimes, all assets in these three classes of assets remain regulated, meaning that the Public Utilities Comission ("PUC") needs to approve any investments by the utilities as well as the utility's allowed return on investment.

[7] Task 2.1.1. Review of potential regulatory models that could be applied in Hawaii.

- Cost of Service (status quo), with or without increased oversight

  Under a COS model, the Investor-Owned Utilities ("IOU") utilities are allowed to earn a return on prudently incurred investment, as well as pass their operating costs through to customers. KIUC, the State's only co-op, is allowed to earn sufficient revenues to earn an appropriate TIER ratio, as described in several earlier working papers. In all cases, under a straight COS model, there are no specific monetary incentives for the utilities to be efficient or minimize costs/rates.

  In the context of this analysis, increased oversight refers to the possibility of an entity being established to ensure that the State's clean energy goals will be achieved by implementing reliability standards across all the electric value chain and providing fair grid access to generators. The level of oversight should not impact the determination of the value or return on investment for assets, and as such impact on the potential for stranded costs.

  In Hawaii, all classes of utility assets (generation, transmission, distribution, other) are currently operated under a COS model, although there are some elements of PBR model in the current regulatory model, as discussed in Task 2.1.2.

- Performance-Based Regulation

  PBR is a regulatory approach to rate regulation that provides a wide range of mechanisms that can weaken the link between a utility's rates and its unit costs and improve efficiency, rewarding and/or penalizing the utility according to its performance vis-à-vis targets or performance standards.

Within those models, it is also possible to break up the vertically-integrated utility so that different regulatory regimes could be applied to a class of assets – for instance, the ISO model described below could be applied to generation assets while the "wires" (transmission or distribution) assets are operated by the utility under a COS or PBR model.

3.1.1 Discussion of potential for stranded costs

The Project Team assumes that all utility assets in all the counties are included in their respective rate base and the costs are recovered through electricity rates. While the bulk of utility assets are comprised of generation, transmission, and distribution assets, other categories such as real estate, inventory (for fuel, materials, and supplies), or "accounting" assets (such as investments related to employee pensions or deferred costs) are also included. Section 3.2 below discusses scenarios where different asset classes may be subject to different regulatory regimes.

For all regulatory models introduced in Section 3.1, the utility assets, or rate base assets, have been procured under the oversight of the PUC and thus can be presumed to be reasonable and necessary to the continued reliable operation of the power grid in each county. Similarly, all independent power producers' ("IPPs") generation assets are under contract with regulated utilities, and the contract costs are also recovered through electricity rates. Indeed, as the load patterns would in no way be affected by the change in the regulatory model, it is reasonable to

expect that all existing assets are needed to ensure continuity of reliable service – at least in the short term.[8]

In this case, since assets remain under a regulated regime, there would not be stranded costs related to the change in regulatory regime under the status quo, status quo with increased oversight, and PBR.[9]

3.2 Regulatory models with potential for unregulated assets

In addition to the COS and PBR models discussed previously, the Project Team introduced two models, the ISO and Distribution-focused, which can result in the deregulation of certain classes of utility assets. Indeed, under these models, the utility can be forced to transfer or divest certain classes of assets, mostly related to generation, to an unregulated subsidiary or the IPP.

- ISO
  An ISO or a regional transmission organization ("RTO") is an independent, membership-based, non-profit organization that ensures reliability and uses bid-based markets to determine economic dispatch for wholesale electric power. Under the ISO model, utilities continue to own and maintain the transmission and distribution system. However, utilities should yield their functions of system planning, dispatch, and day-to-day operations to the ISO. Under an ISO model, the incumbent utility can either retain its generation assets or divest them.

- Distribution-focused model
  There are two potential variants under a distribution-focused regulatory model. The first variant is where the distribution system is still owned and operated by the incumbent utilities, which take on a role as Distributed System Platform Providers ("DSPP"). The second variant is where the distribution systems are still owned by the utilities but are operated by an outside Independent Distribution System Operator ("IDSO") entity.

3.2.1 Discussion of potential for stranded costs

While there are currently IPPs operating in various counties of the State of Hawaii, the independently-owned resources are operating under Power Purchase Agreements ("PPA") with the regulated utility. As such, the generation owners are guaranteed the revenues that are specified in the contracts,[10] allowing them to cover fixed and variable costs and earning them a

[8] The HECO Companies Power Supply Improvement Plan does lay out a retirement schedule for legacy generation resources as new renewable generation comes online. However, for the purpose of this analysis, the Project Team assumes that the change in regulatory model would not affect the longer-term retirement schedule for existing assets.

[9] There may be stranded costs at the time the assets are retired if not fully depreciated, but they would not be caused by the change in regulatory regime but rather by evolution of generation resource mix.

[10] Subject to performance requirements or other terms and conditions specific to each contract.

return on their investment. In turn, the costs of these PPAs for the utility are recovered through the electricity tariffs paid by consumers.

Conversely, the ISO and distribution-focused models would result in the creation of marketplaces, with the owners of generation earning revenues from offering their resources in the markets and earning the market clearing prices if selected.[11] As with all marketplaces, prices can be volatile, and the outcomes depend on the interaction of several factors such as the types of generation resources participating in the markets, fuel prices, load levels, transmission limits, etc. The key difference, however, is that generation owners can no longer count on the recovery of costs, plus a return on their investments, through regulated rates. Instead, they must ensure that their resources are competitive enough to earn the necessary revenues from the markets.

Should a change in regulatory model require the transfer or divestment of certain classes of utility assets, the transfer price for these assets would need to be agreed upon by both parties to the transaction. This agreement would presumably follow a competitive process where multiple interested parties would bid to purchase the portfolio of utility assets, in part or whole, that is being divested. As discussed in Task 1.1.6., if the assets were to remain under a regulated regime after such a transfer, the acquiring entity would expect to earn a regulated return on its investment similar to the return granted to the incumbent utility by the PUC. As such, the transfer prices would be very close to the book value of those assets. However, in this case, the assets would become unregulated, or "merchant," and earn revenues from the markets. As such the acquiring entity will offer to purchase the assets at a price that allows it, based on the expected magnitude of market revenues, to cover its costs and earn their desired return on investment. The purchase price, therefore, will not be based so much on the book value of the assets, as on their value in a market environment over their assumed remaining economic life.

As discussed in Task 1.1.6., stranded costs arise if the market value of assets the utilities must divest, such as generation resources, is lower than their book value. Indeed, at the time the utility made the investments, it was "promised" a fair return over the life of the assets. However, due to the potential divestiture, and assuming the market value is below the assets' book value, the utility would be prevented from earning that return on its investment. Historically, provided that the investments were prudent and verifiable, utilities have been allowed to recover stranded costs from ratepayers. Therefore, generators would potentially have stranded costs with the change in the regulatory regime to the ISO and distribution-focused models.

On the other hand, the regulatory models considered by the Project Team assume that all transmission and distribution assets would remain under a regulated regime and as such would not be a source of stranded costs for the incumbent utilities should there be a change in regulatory regime.

[11] There are several market design structures that could be implemented, which may or may not include markets for energy, capacity, ancillary services, financial transmission rights, etc.

3.2.2 Methodology for the evaluation of potential stranded costs

As introduced previously, the stranded costs calculation compares the value of the utility's assets in the regulated environment with the value of these same assets in the newly formed regulatory environment. In other terms, the stranded costs are computed as the difference between the current market value of the asset and the historical cost of the asset depreciated through time (i.e., book value). In practice, a certain amount of negotiation also takes place between the utility, regulator, and other stakeholders in order to establish the exact amount of stranded costs allowed to be recovered.

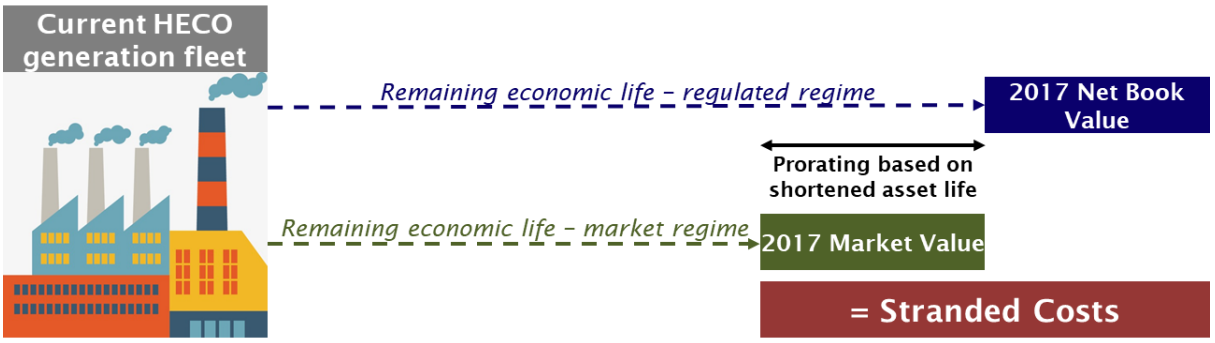
The book value of generation assets for all utilities in the State of Hawaii is disclosed in several regulatory filings such as rate cases and annual reports, as discussed in Task 1.4.1. The market value of these resources, however, can depend on several factors such as the assumed remaining economic life of the assets, competition from other resources, or evaluation of future market conditions.

Under normal circumstances, a well-designed market is structured so that the marginal resource required to ensure the reliability of the transmission system as well as resource adequacy earns enough revenues to cover its going-forward costs. This is true independently of the specific structure of the market, be it an energy and capacity design, or an energy-only design. For purposes of this analysis, the Project Team assumed that the current generation resources in all counties of the State of Hawaii are required for system reliability. Furthermore, in future years some of these resources become superfluous as new generation resources, including renewables, are introduced. These assumptions are based on the HECO Companies' Power Supply Improvement Plan ("PSIP"), which details the reliability requirement for current resources as well as lays out a retirement schedule for legacy resources as new resources come online. It is also possible to draw similar conclusions from KIUC's capital expenditures planning and other long-term planning documents.

In that context, the Project Team assumes that if the counties of the State of Hawaii were to transition to a competitive market structure, these markets would provide sufficient revenues for all current generation resources in the short term in order to ensure reliability. However, in future years, and as the reliability benefit of some older legacy resources disappears, the markets would no longer be able to provide sufficient revenues for those resources to remain online. As such, even though some of these resources would still have a positive book value, their market value to an independent generator would be nil, and they would be retired. The overall market value of these assets, therefore, relies on their remaining economic life, i.e., for how long an independent owner can expect to earn money from these assets.

The methodology for estimating the market value and potential for stranded costs of generation resources adopted by the Project Team therefore hinges on prorating the current book value of assets and comparing its assumed remaining economic life in a regulated regime (based on asset class's average age and depreciation rate) to the assumed remaining economic life in a market regime (based on planned asset retirement date). The approach used by the Project Team is depicted in Figure 3.

Figure 3. Methodology used to estimate stranded costs



3.2.3 Calculation of potential stranded costs

As discussed previously, the entity acquiring assets would value them according to the potential revenues they can generate over their economic life. The economic life represents the length of time an asset can generate revenues. For instance, an asset can become uneconomic following entry of newer resources even though it is not fully depreciated yet.

Using the methodology described in Section 3.2.2, the Project Team estimated the potential stranded costs for utility production assets in the State of Hawaii as illustrated in Figure 1.

3.2.4 HECO

HECO had a total of 1,278 MW of thermal generation capacity in 2017.[12] It has since added Schofield Generating Station ("SGS") to its portfolio. SGS is a 50 MW plant capable of running on a mixture of biofuels and conventional fuels (diesel or oil). If the transition to renewables becomes more aggressive, SGS can transition to operating fully on biodiesel. Therefore, it is expected that the plant will not retire before the forecast horizon (until 2045) and will not result in any stranded costs.

The HECO Companies' response to data requests from the Project Team shows that the gross cost of its production plants as of Q2-2017 was $992.3 million but with a net book value of $634.6 million.[13] Across HECO's generation portfolio, the average undepreciated cost of HECO's generation plants is $532,917/MW as of Q2-2017. The project team used this average figure to estimate the net book value for each generating unit, excluding SGS.

Regulatory filings from HECO's last rate case proceedings show that the average depreciation rate for HECO's production plants was 1.95%,[14] which translates to a book life of 51 years. Based

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[12] HECO. *About Us – Power Facts.* Web. <https://www.hawaiianelectric.com/about-us/power-facts>

[13] HECO. *Response to LEI data request. Exhibit 1b – Plant Information @ Q2-2017.*

[14] HECO. *HECO-WP-2505, Application for Approval of General Rate Case and Revised Rate Schedules and Rules (Docket No. 2016-0328).* December 16, 2016.

on the ratio of net book value to the gross cost of the plant, 64% of HECO's production assets value remains undepreciated. Thus, the Project Team estimated that the plant assets had, on average, 32 years of remaining asset life.

However, HECO's retirement schedule from the PSIP report shows that most of its assets will be retired long before then. In addition to SGS, only three other units are expected to operate beyond 2045 after being converted to run on biodiesel in 2044. Therefore, the Project Team estimated the market value of each generating unit by multiplying its net book value by the ratio of years before retirement to average years of remaining asset life (32, as discussed above); for units scheduled to run beyond the average remaining asset life, the market value was capped at estimated remaining book value.

Stranded costs for HECO's generation portfolio, calculated by subtracting estimated market value from net book value, was estimated at $321.9 million.

3.2.5 MECO

MECO's thermal generation capacity in 2017 stood at 274 MW.[15] The gross cost of MECO's production plants as of Q2-2017 was $411.8 million but with a net book value of $154.3 million,[16] resulting in an average undepreciated cost of $578,699/MW as of Q2-2017. Regulatory filings from MECO's last rate case proceedings show that the average depreciation rate for MECO's production plants was 2.71%,[17] which translates to a book life of 36 years. Based on the ratio of net book value to the gross cost of the plant, 37% of MECO's production assets remains undepreciated. Thus, the Project Team estimated that the plants had, on average, 13 years of remaining asset life.

The Project Team estimated the market value of generation assets using the same approach described for HECO in Section 3.2.4. Stranded costs for MECO's generation portfolio, calculated by subtracting estimated market value from net book value, was estimated at $11.3 million.

3.2.6 HELCO

HELCO had a total generating capacity of 187.8 MW in 2017, of which 183.3 MW was thermal, and 4.5 MW was hydro capacity.[18] The Project Team assumed that the market value of the hydro plants would be the same as its book value since it will not face any regulatory risks of early retirement going forward. The gross cost of HELCO's production plants as of Q2-2017 was $327.5

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[15] MECO. *About Us – Power Facts.* Web. <https://www.mauielectric.com/about-us/power-facts>

[16] HECO. *Response to LEI data request. Exhibit 1b – Plant Information @ Q2-2017.*

[17] MECO. *MECO-1703, Application for Approval of General Rate Case and Revised Rate Schedules and Rules (Docket No. 2017-0150).* October 12, 2017.

[18] HELCO. *About Us – Power Facts.* Web. <https://www.hawaiielectriclight.com/about-us/power-facts>

million but with a net book value of $139.3 million,[19] resulting in an average undepreciated cost of $749,266/MW. The average depreciation rate for HELCO's production plants was 2.52%,[20] which translates to a book life of 39 years. Based on the ratio of net book value to the gross cost of the plant, 43% of HELCO's production assets remains undepreciated. Thus, the Project Team estimated that the plants had, on average, 16 years of remaining asset life.

The Project Team estimated the market value of generation assets using the same approach described for HECO in Section 3.2.4. Stranded costs for HELCO's generation portfolio, calculated by subtracting estimated market value from net book value, was estimated at $12.5 million.

3.2.7 KIUC

The Project Team's analysis of KIUC's generation asset excludes the solar projects developed by the utility under Special Purpose Vehicle ("SPV") ownership, treating the SPV as an IPP. KIUC's total generating capacity stood at 125.3 MW at the end of 2016, of which 124 MW was thermal, and 1.3 MW was hydro capacity.[21] Again, the Project Team assumed that the market value of the hydro plants would be the same as its book value since it will not face any regulatory risks going forward. The gross cost of KIUC's production plants as of Q4-2016 was $152.1 million but with a net book value of $76.0 million,[22] resulting in an average undepreciated cost of $645,695/MW. The average depreciation rate for KIUC's production plants was 2.99%,[23] which translates to a book life of 33 years. Based on the ratio of net book value to the gross cost of the plant, 50% of KIUC's production assets remains undepreciated. Thus, the Project Team estimated that the plants had, on average, 16 years of remaining asset life.

The Project Team estimated the market value of generation assets using the same approach described for HECO in Section 3.2.4. Stranded costs for KIUC's generation portfolio, calculated by subtracting estimated market value from net book value, was estimated at $31.9 million.

3.2.8 Factors that can affect the magnitude of stranded costs

The Project Team's estimates of stranded costs are based on several assumptions, as described in Section 3.2.2. These assumptions are intended to provide a base case to estimate stranded costs. In reality, the actual magnitude of stranded costs may differ due to factors for which sufficient data is not available to include in the model. Some of these factors are discussed below.

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[19] HECO. *Response to LEI data request. Exhibit 1b – Plant Information @ Q2-2017.*

[20] HELCO. *HELCO-1603, Application for Approval of General Rate Case and Revised Rate Schedules and Rules (Docket No. 2015-0170).* September 19, 2016.

[21] KIUC. *About Us – Energy Information.* Web. <http://website.kiuc.coop/content/energy-information>

[22] KIUC. *Annual Financial Report to the PUC 2016.*

[23] KIUC. *KIUC Depreciation Study.*

1. Market risk vs. regulatory certainty

   The inclusion of generation in the incumbent utilities' regulated asset base allows the utilities to earn a return (for the HECO Companies) or at least cover their operating costs in case of KIUC. This holds true regardless of the amount of new generation capacity procured from IPPs if the utilities deem the asset to be necessary for reliability. A competitive environment changes this dynamic over the medium- to long-term. Thermal plants that are currently necessary for reliability may not be required due to the entry of new firm generation assets into the market. This is particularly true of thermal plants since they are vulnerable to fuel price shocks.

   The estimates of stranded costs in Section 3.2.2 depends on the assumption that the generating units will not retire before their intended retirement date as forecast by the incumbent utilities. If prospective buyers are disinclined to take a longer-term view, it reduces the market value of the assets and correspondingly increases the stranded costs. For instance, the Project Team's methodology assumes that there will be no stranded costs for a generating unit scheduled to operate through at least 2045 because the unit would be fully depreciated by then (assuming no capex upgrades to the unit). However, a buyer may be willing only to pay a price based on the assumption that the unit operates through 2030, resulting in stranded costs for the undepreciated portion of assets as of that year. Figure 4 indicates how the stranded costs for each utility increase as the time horizon of the buyer is shortened, where 100 years represents the assets remaining operational until their current retirement schedule.

Figure 4. Stranded costs - time horizon sensitivities

	Years			
Stranded costs ($000s)	**100**	**20**	**15**	**10**
HECO	321,852	364,878	388,518	446,970
HELCO	12,513	12,513	18,699	52,467
MECO	11,333	11,333	11,333	42,757
KIUC	31,926	31,926	37,293	42,660

Source: Project Team analysis.

2. Higher cost of equity higher for merchant than regulated entities

   The analysis above does not account for the differences in costs of capital for prospective buyers vs. the incumbent utilities once the regulated assets become merchant generation. Equity investors are willing to finance regulated assets at more favorable rates due to greater certainty of returns. Therefore, the higher the required rate of return sought by a prospective buyer's equity investors, the lower the price it would be willing to pay for the current utility assets, resulting in higher stranded costs.

3. Buyers having more bearish views on market conditions

   Buyers of current utility generation assets may also have different views on how Hawaii's power sector will evolve, especially with increased competition. Compared to forecasts

by the incumbent utilities, their market outlook could be more pessimistic – faster growth in DERs (including demand response and energy efficiency), slower load growth, more rapid declines in costs of renewables and storage, and higher fuel prices in the future. Market values of current utility generation would then be lower with higher stranded costs.

4. Single asset vs. portfolio purchase

   The Project Team's analysis is based on a portfolio view of each utility's generation assets. The market value for each generation unit is estimated using a portfolio-wide average book life and net book value per MW. This approach may result in very different stranded cost estimates. Older plants may have lower market values than estimated using the Project Team's approach, but they are also more likely to have low book values remaining. Newer plants may be more desirable for buyers but whether they will be desirable enough for the market price to cover their book value is uncertain.

4 Appendix A: Scope of work to which this deliverable responds

Task 2.2.4 **Summary analysis and conclusions related to estimating stranded costs for each regulatory model.** CONTRACTOR shall identify and estimate the impact of any potential stranded assets as a result of change in regulatory model.

DELIVERABLE FOR TASK 2.2.4. CONTRACTOR shall provide its conclusions and all work related to estimating stranded costs for each regulatory model. CONTRACTOR shall consider the economic value of these assets and whether these assets are needed under a given regulatory model in order to estimate the total magnitude of potential stranded costs. CONTRACTOR shall provide a summary of analysis and conclusions of this research in MS Excel and PowerPoint. CONTRACTOR shall submit deliverable for TASK 2.2.4 to the STATE for approval.

5 Appendix B: List of works consulted

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Stakeholder Workshop Summary: Regulatory Models

prepared for DBEDT by London Economics International LLC and Meister Consultants Group

September 28, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group ("MCG"), was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals; this document is one of several working papers associated with that engagement. This Stakeholder Workshop Summary for the Utility Regulatory Stakeholder Workshops is responsive to Task 2.2.5 which includes the preparation of an outreach plan to solicit public input from each island currently served by an electric utility on the results of Tasks 2.1.1 through 2.2.4 as well as this report to document the results of the Stakeholder Outreach. This memo provides a summary of the stakeholder workshop conducted on June 12 through 22, 2018 on Hawaii, Kauai, Lanai, Maui, Molokai, and Oahu.

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List of acronyms

B-Corp	B-corporation
Co-op	Cooperative Utility
DBEDT	Department of Business, Economic Development & Tourism
DER	Distributed Energy Resource
DSPP	Distributed System Platform Provider
ESM	Earnings Sharing Mechanism
EV	Electric Vehicle
GHG	Greenhouse Gas
HCEI	Hawaii Clean Energy Initiative
HECO	Hawaiian Electric Company
HEI	Hawaiian Electric Industries
HELCO	Hawaii Electric Light Company
HERA	Hawaii Electricity Reliability Administrator
HSEO	Hawaii State Energy Office
IOU	Investor-Owned Utility
IPP	Independent Power Producer
ISO	Independent System Operator
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International
LMI	Low- or Moderate-Income
MCG	Meister Consultants Group
MECO	Maui Electric Company
NERC	North American Electric Reliability Corporation

PBR	Performance Incentive Mechanism
PIM	Power Purchase Agreement
PPA	Public Utilities Commission
PUC	Photovoltaics
PV	Request for Proposals
RFP	Renewable Portfolio Standard
RPS	Regional Transmission Organization
RTO	

1 Executive Summary

1.1 Background

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. London Economics International LLC ("LEI") and Meister Consultants Group ("MCG," collectively "the Project Team") were contracted to perform this study.

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria:

- achieve state energy goals;
- maximize consumer cost savings;
- enable a competitive distributions system; and
- eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation.

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will aid in identifying the process to be followed to form such ownership and regulatory models and determining whether such models would create synergies in terms of:

- increasing local control over energy sources serving each county;
- ability to diversify energy resources;
- economic development;
- reducing greenhouse gas emissions;
- increasing system reliability and power quality; and
- lowering costs to all consumers.

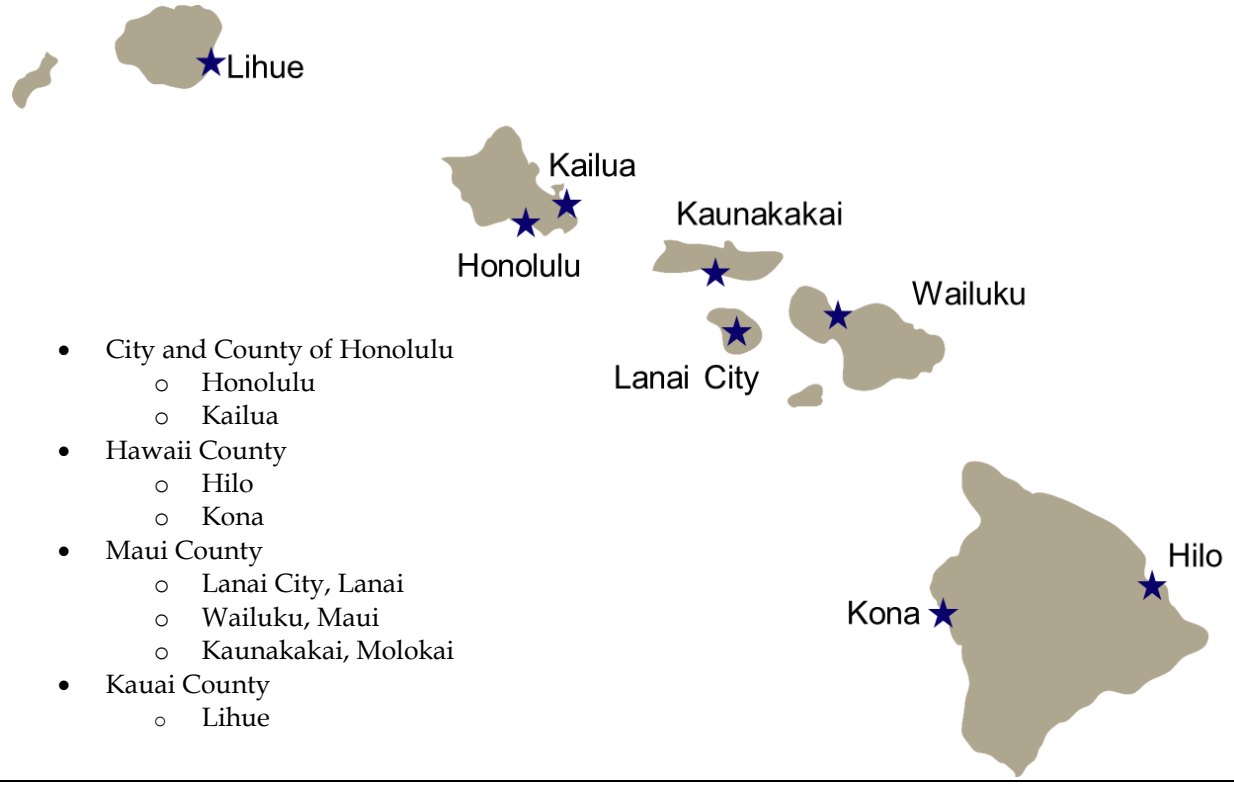
This report, the Stakeholder Workshop Summary: Utility Regulatory Models, has been prepared to fulfill requirements under Task 2.2.5 in the project scope of work and provides a summary of the stakeholder workshops conducted on each island between June 12th and June 22nd, 2018.

The results from these workshops and the other stakeholder engagement conducted throughout this project will be incorporated into the analyses and the final report, to be submitted to DBEDT in October 2018. Nevertheless, we want to note that the survey of the public has never been suggested to be a statistically valid sampling of the population. An e-mail address, DBEDT.UtilityBizModStudy@hawaii.gov, has been set up to collect feedback over the course of the project. All feedback related to the regulatory model analysis that is received by August 31st, 2018 were summarized and added to this report. All other feedback will be incorporated into future reports submitted under this project.

1.2 Utility Regulatory Model Stakeholder Workshops

The Stakeholder Workshops for the Utility Regulatory Models were completed between June 13, 2018, and June 22, 2018. There were eight (8) public workshops held at each location shown in Figure 1. Additionally, the project team conducted a workshop at the VERGE conference in Honolulu on June 12th, 2018.

Figure 1. Location of the meetings



- City and County of Honolulu
  - Honolulu
  - Kailua
- Hawaii County
  - Hilo
  - Kona
- Maui County
  - Lanai City, Lanai
  - Wailuku, Maui
  - Kaunakakai, Molokai
- Kauai County
  - Lihue

The objectives of the workshops were to provide stakeholders with information regarding the various regulatory models under consideration, to receive their input on the priorities for regulation of the electric sector, and input on the advantages and disadvantages of different regulatory models in meeting community priorities. Combined, 75 stakeholders participated in the public workshops, and more than 100 participated in the workshop at VERGE.[1]

In addition to the workshops, the Project Team has conducted multiple bilateral meetings as part of the ongoing stakeholder engagement process. Between June 12th and June 22nd, the Project Team met with 20 energy industry, government, non-profit, and other stakeholders from across the state and received input that varied from support for Performance-Based Regulation ("PBR") implementation, to interest in only minor revisions to the status quo, to concern for unintended

[1] The majority of participants at VERGE did not sign in.

consequences due to the difficulties in designing PBR well, to support for lighter regulation of cooperative utilities ("co-ops").

1.3 Key findings from workshops

While the discussions at each workshop were unique as stakeholders expressed their priorities and concerns, there were some themes that came up multiple times during the two weeks, namely:

- reliable electricity is a priority, and the current regulatory model has been successful at ensuring utilities provide reliable service;
- minimizing rates now and in the future is a priority;
- that stakeholders greatly value the ability to be engaged in and influence utility decisions to ensure they are aligned with community needs;
- there is much interest in improving resiliency in the electrical grid across the state, particularly in relation to severe storms;
- there is demand for more renewable energy, from more diverse sources, and for more opportunity for customer-sited generation;
- the regulatory model must allow for and encourage innovation so that the utility can meet its goals most cost-effectively;
- there is concern that the current regulatory model does not allow for the competition in generation necessary for generation to be developed in the most cost-effective way; and
- that any model must consider the equity of costs and access to renewable resources as there is concern that grid defection is impacting the Low or Moderate-Income ("LMI") community the most.

1.4 Status Quo

All stakeholders agreed that the current regulatory model results in the provision of reliable electricity to the state. There was general concern in relation to the HECO Company utilities[2], however, that the status quo does not encourage the utilities to invest sufficiently in improving grid resiliency. Across the state, stakeholders believed that this model has not been successful in minimizing electric rates. Many stakeholders expressed dismay over the lack of community involvement in the utility decision-making process required under the status quo and expressed that the utility is not incentivized to take action or make investments in line with community priorities. Some stakeholders suggested that increasing representation from each island on the Public Utilities Commission ("PUC") would be a good first step to ensuring that priorities from each island are addressed. Some stakeholders explained that this model does not allow sufficient access to the grid for independent power producers ("IPPs") and does not sufficiently incentivize

[2] The HECO Company utilities include Hawaiian Electric Company ("HECO"), Hawaii Electric Light Company ("HELCO"), and Maui Electric Company ("MECO"). Hawaiian Electric Industries ("HEI") is the parent company for these three utilities. The term "HECO Companies" is used throughout this report when referring to all three together.

investments in renewables. Overwhelmingly, stakeholders discussed that the PUC does not have sufficient resources to handle its current tasks.

1.5 Hawaii Electricity Reliability Administrator ("HERA")

In general, stakeholders did not think that HERA would be a good solution for Hawaii. While many noted that it might increase grid access and increase deployment of renewables, a majority of stakeholders thought that HERA would be redundant, since the PUC already assumes much of the role HERA would be playing, and increase overall costs.

1.6 Independent System Operator ("ISO")

Though it was recognized that an ISO would increase competition, stakeholders agreed that it would be too costly and that the market is too small in Hawaii for an ISO to work.

1.7 Distributed System Platform Provider ("DSPP")

Stakeholder opinions varied greatly regarding a DSPP model. While many explained that this model would not work in Hawaii, others saw it as a way to increase competition and deployment of distributed energy resources ("DERs"). Many stakeholders mentioned that the costs would be too high, particularly the necessary up-front investments required to implement this model.

1.8 PBR

Stakeholders were supportive of using incentives under a PBR framework to encourage utilities to make investments and take actions that are in line with community and policy goals. The potential metrics discussed significantly varied and included cost stabilization, cost equity, increased renewable generation, incorporation of community priorities, the reliability of service, and grid resiliency. Multiple stakeholders suggested that it would be critical for representatives from each island to be involved in designing the metrics. There was general agreement that linking utility revenues to performance would be beneficial.

Many stakeholders highlighted that it would be difficult to design and implement PBR well and there was substantial concern about unintended consequences that would result if it is not designed well. As a result, some stakeholders explained that it might be too risky. Preferences varied from a PBR model that would create minor adjustments to the status quo to one that would result in a significant overhaul of the system.

1.9 Lighter Regulation of Co-ops

There was broad support for lighter regulation of co-ops, mainly from stakeholders on Kauai. Many stakeholders said that the Kauai Island Utility Cooperative ("KIUC") has demonstrated the ability to manage and operate the utility well and that PUC regulations are unnecessary. Some stakeholders suggested that Hawaii follow the example on the mainland where co-ops are not regulated as heavily as investor-owned utilities ("IOUs"). Stakeholders on Kauai noted that a reduction in regulations would reduce costs for both KIUC and the PUC.

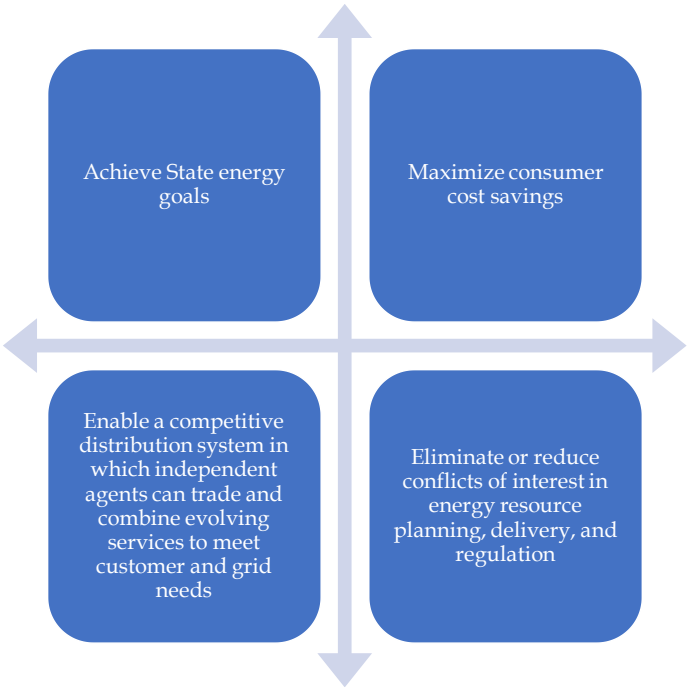
2 Introduction and scope

2.1 Project description

DBEDT was directed by the state legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. LEI and MCG, through a competitive sealed proposals procurement,[3] was contracted to perform this study.[4]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[5] listed in Figure 2.

Figure 2. State's key criteria



Source: Scope of Services under Contract No. 65595

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models and determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy

[3] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[4] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[5] House Bill No. 1700 Relating to the State Budget.

resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[6]

2.2 Role of this deliverable relative to others in the project

This deliverable has been prepared to fulfill requirements under Task 2.2.5 in the project scope of work. Task 2.2.5 requires the Project Team to prepare a report documenting the public outreach. Comments received from the workshops will be analyzed and considered as we conduct the other tasks under this project, namely:

- Task 2.2.6. - Ranking process and rationale for the recommendation of three feasible utility regulatory models;
- Task 2.3.1. - Identification of various steps, timeline, and costs required to change from the current regulatory model to new models, including necessary approvals;
- Task 2.3.3. - Identification of risk for each regulatory model, analysis of each risk, and assessment of the overall risk profile for each regulatory option;
- Task 2.3.4 – Assessment of the potential impact of different models on state agencies and specific stakeholders, including the PUC and consumer advocate; and
- Task 2.5.5. - Identification of funding mechanisms for each regulatory model and the potential cost implications for customers.

[6] Hawaii Contract No. 65595. Scope of Services.

3 Stakeholder Engagement Overview

3.1 Objectives

Throughout the project, the Project Team is meeting with stakeholders representing interests across the economy from each island to both receive their input on what the utilities' role is in achieving state policy goals and providing interim and final results of the analyses. The broad objectives are to:

- introduce the public to this project and provide multiple pathways for public input;
- provide information to support the public's understanding of the differences between and trade-offs of multiple utility ownership and regulatory models; and
- provide information on possible approaches for Hawaii to best achieve the state's clean energy and other policy goals.

There are two groups of stakeholders: the Core Group and the Public Group. The Project Team convened a Core Group of stakeholders including representatives from the organizations listed below on September 22, 2017, and October 13, 2017.

Figure 3. Core Group

Public Sector	County Energy Coordinators	County Economic Development Boards	Utilities
○ DBEDT ○ Consumer Advocate ○ Public Utilities Commission ("PUC")	• Hawaii • Honolulu • Maui • Kauai	• Hawaii • Honolulu • Maui • Kauai	○ Hawaiian Electric Company ("HECO") ○ Hawaiian Electric Light Company ("HELCO") ○ Kauai Island Utility Cooperative ("KIUC") ○ Maui Electric Company ("MECO")

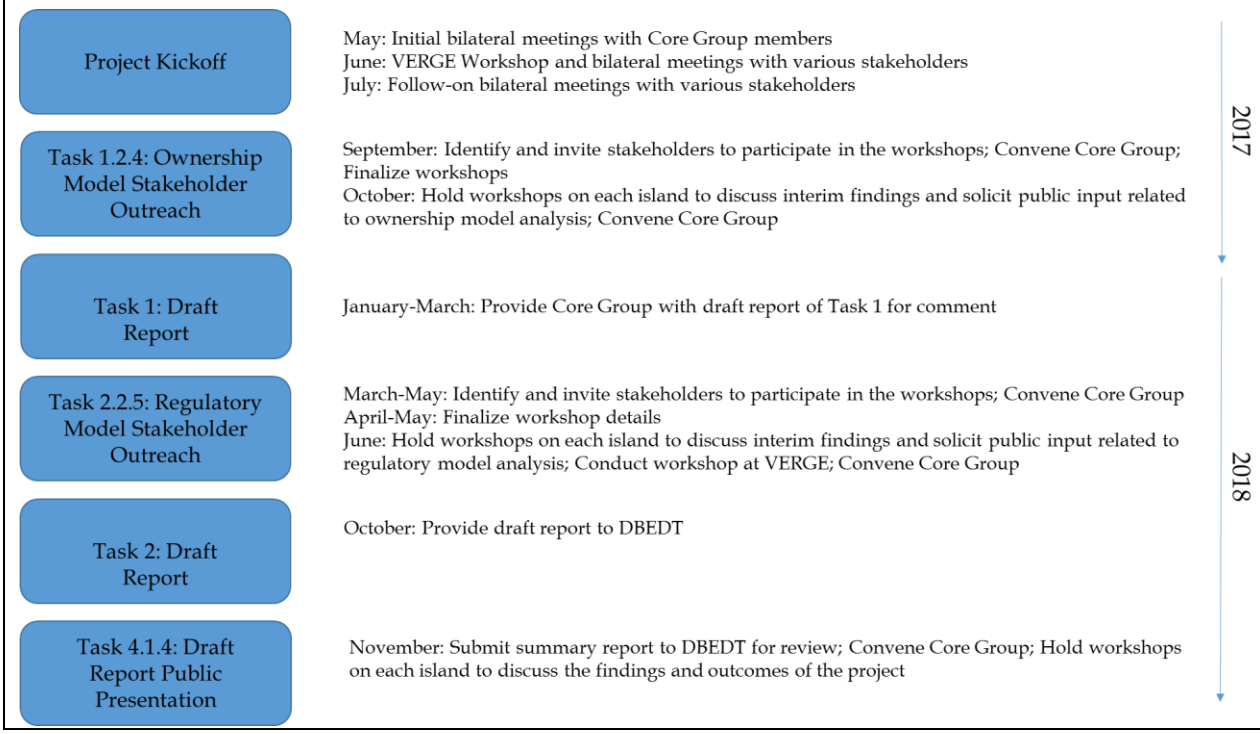
The Project Team will continue to engage with the Core Group multiple times throughout the project to solicit their input on the process for stakeholder engagement, the stakeholders with whom to meet and to comment on interim and final analyses. These meetings will take the form of a conference call, to be coordinated and scheduled by the Project Team. The proposed timing for convening the Core Group is outlined in Figure 4 below.

The Public Group is open to any parties interested in this project's scope. Therefore, the Public Group will include representatives from the general public, state and county institutions, non-profits, the private sector, academia, and the federal government (primarily the U.S. Department of Defense and U.S. Department of Energy).

3.2 Timeline

Over the span of the project, the team will actively engage with stakeholders at multiple points and will be open to additional discussions as requested by stakeholders. The figure below illustrates a high-level timeline of the stakeholder engagement opportunities that are currently planned, broken out by the task. While target months are provided for all activities, these are subject to change as the timeline of the broader project evolves.

Figure 4. Indicative Timeline for Stakeholder Engagement



4 Stakeholder Engagement: Utility Regulatory Models

For Task 2.2.5, the team conducted stakeholder workshops on each island served by an electric utility and led a workshop at the VERGE conference in Honolulu. The Stakeholder Outreach Plan, which was submitted to DBEDT on April 4, 2018, provided a detailed discussion of the stakeholder engagement process conducted for this task. This section provides a summary of the process and documentation of the discussions on each island.

4.1 Objective and Scope

The primary goals of the Utility Regulatory workshops were to:

- solicit public input on the topic of utility regulatory models from stakeholders on each island;
- create opportunities for everyone to share his/her opinion on Hawaii's utility regulatory model;
- provide a high-level discussion of the different regulatory models identified by the Project Team;
- provide clear, easy to understand and objective information on the differences between utility regulatory models; and
- provide clear information on the next steps that the team will be taking and future opportunities for stakeholders to participate or provide feedback.

The Project Team anticipated that the participants would have a varied knowledge of the energy sector and utility regulatory models, ranging from the general public with a more basic understanding of the sector to experts in the field. As such, the public workshops were designed to be high level and focus on building a common understanding of definitions and terms, the trade-offs between different utility regulatory models, and developing an understanding of what the community sees as the role of regulation, based on the analysis conducted for this project. The VERGE workshop included more technical discussions as the audience was expected to have more familiarity with the energy sector.

Additionally, the number of participants was expected to vary greatly by island. As such, the breakout sessions were designed and selected based on approaches that work well for the number of participants at each workshop.

4.2 Administration of Workshops

4.2.1 Workshop Administration

The community workshops were administered and facilitated by the Project Team members, with one Project Team member designated as the lead facilitator. The DBEDT representatives provided welcoming and concluding remarks, and otherwise observed or responded to questions as needed. The VERGE workshop was facilitated by the Project Team with support from DBEDT staff for facilitating small group discussions. There were between three and four Project Team members at each workshop. The workshops were completed over a two week period, divided among two teams of facilitators:

Team 1:

- Lead Facilitator: Ryan Cook
- Facilitator: AJ Goulding
- Facilitator: Gabriel Roumy
- Facilitator: Tianying Lan

Team 2:

- Lead facilitator: Ryan Cook
- Facilitator: Sarah Booth

- Facilitator: Len Trinidad
- Facilitator: Tianying Lan

4.2.2 Workshop Agenda

4.2.2.1 Community Workshops

The workshops in Kailua, Lihue, Hilo, and Kona were scheduled from 5:30 pm - 7:00 pm and the workshops in Honolulu, Wailuku, Kaunakakai, and Lanai City were scheduled from 6:00 pm - 7:00 pm. All workshops followed the agenda provided in Figure 5, with the timing shifted a half an hour later for the workshops which began at 6:00 pm.

Figure 5. Workshop Agenda

Time	Topic Addressed	Overview
5:30pm to 5:40pm	Welcome and project introduction	• DBEDT provides a brief welcome to the project and introduces LEI • If there is a small enough group, LEI asks attendees to introduce themselves – in large meetings this will happen in small groups • LEI provides an overview of the project purpose and timeline, and the goal of today's session
5:40pm to 6:10pm	Regulatory Model Overview and PBR Detail	• LEI provides an overview of each regulatory model considered and provides detail on PBR • LEI asks if there are clarifying questions (asking the group to hold opinions on models for the small group discussion)
6:10pm to 6:30pm	Large Group Facilitation	• LEI introduces MCG • MCG walks through large-group facilitation sessions on priorities, and thoughts on what's working well and what could be improved • If the group is very large, this may be split into two groups
6:30pm to 7:00pm	Small Group Facilitated Discussion	• MCG provides an overview of the facilitated session and divides the group into an appropriate number of small groups • At each table, facilitator conducts small group session and records notes
7:00pm to 7:05pm	Report Out, Next Steps, Close	• MCG reconvenes group as a whole • Each facilitator comes to the front and provides a 1-2 minute overview of the highlights of their group's discussion • LEI provides an overview of next steps and ways to stay engaged and notes that staff will stay in the room for continued discussion until 7:30 • DBEDT thanks the audience for attending and closes the session

4.2.2.2 VERGE Workshop

The VERGE workshop was held on June 12th from 8:30 am – 12:30 pm. The workshop followed the agenda in Figure 6.

Figure 6. VERGE Workshop Agenda

Time	Topic Addressed	Overview
8:30am to 8:40am	Arrival time	• Time for participants to take their seats and allow for late arrivals • Invite participants to sign-in as they arrive
8:40 am to 8:50 am	Welcome and project introduction	• DBEDT provides a brief welcome to the project and introduces the team • LEI provides an overview of the project purpose and timeline, and the goal of today's session
8:50am to 9:20am	Regulatory Model Overview and PBR Detail	• LEI provides an overview of each regulatory model considered, and discusses PBR in more detail • No Q&A at this point
9:20am to 10:30am	Panel Discussion on Regulation and PBR Specifically	15 Min - Intros • LEI introduces MCG • MCG introduces panelists, who seat themselves at the front. • Each panelist, in turn, provides a 2-5 min introduction of their view on the topic 40 Min – Moderated Panel • MCG moderates panel discussion 20 Min – Audience Q&A • Audience Q&A to the panel
10:30am to 10:45am	Break	• At end of the panel, MCG releases audience for a brief break, asks to reconvene at their tables afterward
10:45am to 11:55am	Small Group Facilitated Discussion	• MCG provides an overview of the facilitated session to full audience and releases group to small tables • At each table, facilitator conducts small group session and records notes

Time	Topic Addressed	Overview
11:55am to 12:05pm	Next Steps, Close	• MCG reconvenes group as a whole • LEI provides an overview of next steps and ways to stay engaged and notes that staff will stay in the room for continued discussion until 12:30 • DBEDT thanks the audience for attending and closes the session

4.2.3 Materials Provided to Participants

All participants at the community and VERGE workshops were provided with a worksheet containing a summary of regulatory models being analyzed for this project. The worksheet is listed in Appendix A beginning on page 65.

4.3 Workshop Content

4.3.1 Team Presentations

The Project Team provided overview slides that were used all, or in part, at all meetings. The slides, which are available at https://energy.hawaii.gov/utility-model, provided:

- an overview of the project;
- a discussion of the current role of the PUC and the utilities' activities in the generation and supply of electricity;
- a high-level presentation of the characteristics, pros, and cons of the different utility regulatory models being analyzed for this project; and
- information on future opportunities for stakeholders to participate and provide input.

4.3.2 Format for Stakeholder Discussions

There were two main sections of the community workshops focused on stakeholder discussions:

1. Large Group Discussion on Regulatory Priorities
2. Small Group Discussion on Regulatory Models

The Large Group Discussion was facilitated by one of the team's facilitators who asked the participants to talk about their priorities for utility regulation, how regulation is working well, and areas for improvement in the regulatory model. The comments were written down on note cards and arranged thematically, either on a pinboard or table.

The Small Group Discussion focused on discussing the benefits and drawbacks of the various regulatory models, as well as the challenges to transitioning to different models. For workshops

with more than 15 participants, the participants broke into smaller groups for this discussion.[7] All discussions were facilitated by a Project Team member to ensure the conversations stayed productive and relevant, and that all participants were given the opportunity to speak if they desired to do so.

VERGE was organized differently and included a panel discussion with time for audience questions and facilitated discussions with the large group as a whole followed by facilitated discussions in smaller groups.

4.4 Stakeholder Workshop Schedule

Figure 7 lists the date, location, and venue of each of the stakeholder workshops. Team 1 held two meetings on Oahu and one on Kauai. Team 2 held one meeting on Maui, Molokai, Lanai, and two on the Island of Hawaii. In addition to the community workshops, Team 1 conducted the workshop at the VERGE conference.

Figure 7. Stakeholder Workshop Schedule

Team 1			
	Island	**Town**	**Venue**
12-Jun	Oahu	Honolulu	VERGE
13-Jun	Oahu	Kailua	Enchanted Lake Elementary School
14-Jun	Oahu	Honolulu	Hawaii Foreign-Trade Zone No. 9
15-Jun	Kauai	Lihue	Kauai High School
Team 2			
	Island	**Town**	**Venue**
18-Jun	Maui	Wailuku	Waikapu Community Center
19-Jun	Molokai	Kaunakakai	Mitchell Pauole Main Hall
20-Jun	Lanai	Lanai City	Lanai Community Center
21-Jun	Hawaii	Hilo	Waiakea High School
22-Jun	Hawaii	Kona	Natural Energy Laboratory of Hawaii Authority

[7] The number of small group breakouts was determined based on the number of participants. For Honolulu, Kailua, Wailuku, Kaunakakai, Lanai City, Hilo, and Kona there was one group discussion. For Lihue there were two small groups.

4.5 Outreach for Stakeholder Workshops

To announce the workshops and invite stakeholders, the Project Team supported DBEDT's outreach efforts. DBEDT conducted outreach through four primary channels:

1. Press release to media contacts
2. Email invitation to stakeholders
3. Discussion with the Core Group
4. Outreach through the Hawaii State Energy Office ("HSEO") website and social media outlets

In addition, outreach was conducted through the promotion of the VERGE conference, and the project team promoted community-level events as part of the VERGE workshops.

The Project Team prepared flyers that were used to announce the workshops (Appendix B: Outreach Flyers). Email invitations were sent to more than 1,900 stakeholders on April 16, 2018 and May 21, 2018 (Appendix D: Email Invitation Text). The stakeholders that received email invitations were identified in discussion with DBEDT, the Core Group, bilateral meetings with stakeholders in Hawaii, through interactions at VERGE, through previous interaction with the project team for this project, and through the Hawaii Clean Energy Initiative ("HCEI"). The invitations provided a summary of the workshop goals and a link to the flyers where participants could sign-up for the event. Additionally, the Project Team provided the Core Group members with the logistics for the meetings on each island and requested that they share the information with their contacts and networks as appropriate. DBEDT also posted the information on its Facebook page and Twitter feed.

4.6 Workshop Participants

The workshops were attended by stakeholders representing county organizations, state organizations, utilities, non-profits/community groups, academia, local and state elected officials, and the private sector. There were 75 participants at the 8 stakeholder workshops and more than 100 stakeholders at the VERGE workshop (see

Figure 8 and Figure 9 for details).[8] Stakeholders that were unable to attend have been encouraged to submit feedback to DBEDT.utilitybizmodstudy@hawaii.gov. Feedback will be collected over the course of the project.[9] At the county level, workshop participation ranged from 10 in Hawaii County to 30 in Maui County.

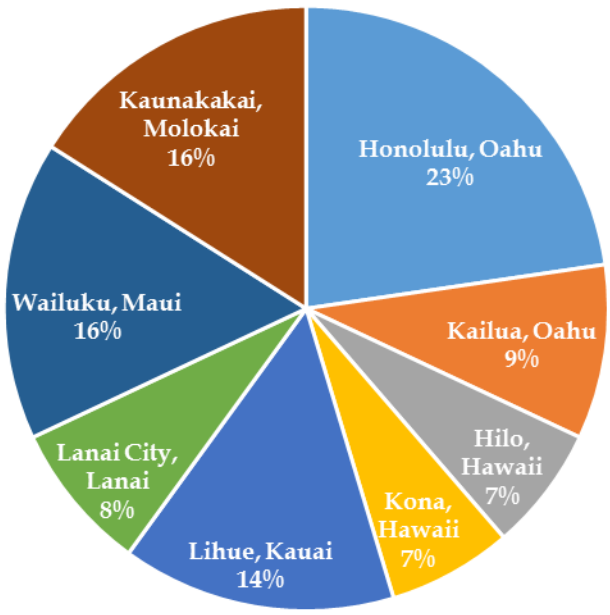
[8] There is some double-counting as a few people attended both VERGE and a workshop and few attended multiple workshops.

[9] Feedback received at this email is not included in this report. Feedback received through August 31st, 2018 will be summarized in an addendum to this report. Feedback received after August 31st will be incorporated into future reports for this project.

Figure 8. Workshop Participation

County (Town, Island)	Participants
City and County of Honolulu	24
Honolulu, Oahu	17
Kailua, Oahu	7
Hawaii County	10
Hilo, Hawaii	5
Kona, Hawaii	5
Kauai County (Lihue)	11
Maui County	30
Lanai City, Lanai	6
Wailuku, Maui	12
Kaunakakai, Molokai	12
Total	75

Figure 9. Percentage of Total Participants at each Workshop



5 Stakeholder Discussions

A significant portion of each workshop focused on facilitated stakeholder discussions to receive input from participants on their priorities for electric utility regulation and the advantages and disadvantages of different regulatory models in achieving the community's priorities. The following sections provide a summary of the discussions from each workshop. A high-level overview of the discussions is presented in Figure 10, Figure 11, Figure 12, Figure 13, and Figure 14. There were often differences of opinions among stakeholders at each workshop, and these summary tables are not meant to imply a consensus of the stakeholders present nor of the community in its entirety.

Figure 10. Summary Table of Workshop Discussions: City and County of Honolulu

Location	*Top Priorities*	*Discussion Highlights by Regulatory Model*		
		Status Quo	**PBR**	**Other Models**
Honolulu	Resiliency and reliability Renewables, including DERs Innovation and new technology adoption Affordability	Ensures reliable electricity Rates are too high Improvements needed for resiliency Does not provide sufficient access to the grid for renewables or IPPs Does not incentivize the utility to make the best investments for the system	Incentivizes utility to take actions in line with ratepayer and policy goals Encourages flexibility Complicated and difficult to design well High potential for unintended consequences	HERA could increase accountability, grid access, and reliability but may be redundant ISO would increase competition, but the market is too small Uncertain about how DSPP model would work
Kailua	Increasing renewables Competition in generation	Ensures reliable electricity Has resulted in major energy efficiency improvements Incentivizes the utility to make capital investments Does not sufficiently incentivize investment in renewables	Incentivizes more efficient utility operations May be too risky for utility	DSPP model would create competition and opportunities for renewables ISO would increase competition but may be too risky Supportive of reduced regulation of KIUC

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sarah@boothcleanenergy.com

Figure 11. Summary Table of Workshop Discussions: Hawaii County

Location	*Top Priorities*	*Discussion Highlights by Regulatory Model*		
		Status Quo	**PBR**	**Other Models**
Hilo	Reducing rates and considering equity issues Increasing renewables Grid flexibility and resiliency Market competition should drive investments, not policy	Reliable electricity Too driven by politics instead of market Ratemaking process is too complicated for individuals to understand Needs more local representation on PUC	Metrics seen as a good way to align utility actions with community goals Prefer incentives to penalties Metrics could include equity, load stability (mitigate grid defection), and cost stabilization	Need the flexibility to allow for changing technologies Different models may work on different islands Any model must consider impacts on LMI community ISO and DSPP models would not work
Kona	Resiliency Increasing renewables Flexibility to adopt new technologies Responsive to customer needs	Supply and demand is well balanced Utility is not responsive to community Inflexible which inhibits adoption of new technologies PUC is too cautious and favors the utility in decisions	Increases the link between utility revenues and performance Metrics with specific timelines would be useful Metrics could include renewable generation and diversity of renewables	Regulation should protect the public interest, not increase business costs nor stifle innovation Too complex of a model will be too complicated to manage HERA could increase renewables and improve access to the grid for non-utility players but may be redundant DSPP may be the only functional model in 5 years as DERs increase

Figure 12. Summary Table of Workshop Discussions: Kauai County[10]

Location	Top Priorities	Discussion Highlights by Regulatory Model		
		Status Quo	**Lighter Regulation for Co-ops**	**Other Models**
Lihue	Not discussed	Reliable electricity PUC is overburdened Current regulation is costly and cumbersome for KIUC, particularly rate cases	Co-ops are not regulated as heavily on the mainland KIUC is more responsive to customers than PUC PUC could provide dispute resolution, but there are already options for this (elections, member votes) Lighter regulation would reduce costs for the PUC	HERA and ISO would not work DSPP would be too costly

[10] The discussion at the Kauai Workshop focused primarily on lighter regulation for co-ops, with no discussion of stakeholder priorities in general or of PBR implementation since KIUC is exempted from the PBR docket.

Figure 13. Summary Table of Workshop Discussions: Maui County

Location	Top Priorities	Discussion Highlights by Regulatory Model		
		Status Quo	**PBR**	**Other Models**
Lanai	Responsiveness to community needs Minimizing rates Increasing incentives for residential and businesses to deploy renewables	Reliable electricity MECO maintains a strong relationship with the community Does not incorporate community priorities	Metrics would ensure community needs are incorporated Prefer modification of status quo to radical change Metrics could include efficiency, rate costs, reliability, transmission and distribution upgrades, power restoration after the outage, reduction in dependency on oil, environmental impacts, resiliency Lanai involvement in designing metrics	Interested in the potential for a hybrid model Control of any model must be loca
Maui	Resilient grid Independence from oil Increased renewables Simplified interconnection process Grid modernization	Stakeholders understand how this model works Reliable electricity PUC's independence is beneficial Improved community engagement process Does not address cost shift and equity concerns Biased toward supply-side solutions	Some PBR components already incorporated Concern about unintended consequences Better align utility profits based on performance Will not address all issues [e.g., equity, electric vehicles ("EVs"), technology innovation] PUC would need more resources Metrics may be politicized	ISO implementation in Hawaii would have to be very different than on mainland but could increase equality or the grid Disagreement if HERA would be a good solution

Location	Top Priorities	Discussion Highlights by Regulatory Model		
		Status Quo	PBR	Other Models
Molokai	Minimizing electricity costs Community engagement in utility decisions Increased distributed generation Competitive and public bidding process Efficient operations	Does not align with community priorities or include community involvement in decisions Procurement process does not require community input Does not address the long-term sustainability of projects nor prioritize diversity in renewable generation	Could give the community more input in decisions Metrics could include rate reduction, improving grid infrastructure, maximizing community benefits Want Molokai residents involved in establishing metrics	Would like a model that encourages economic development on Molokai, is inclusiv of small communities, incorporates community input, and includes assessments of environmental and cultural concerns Support diversity o renewables Market is too small for an ISO

Figure 14. Summary Table of Workshop Discussions: VERGE

Location	Top Priorities	Discussion Highlights by Regulatory Model		
		Status Quo	**PBR**	**Other Models**
Honolulu	Reliability and resiliency Reducing rates and equitable rates Achieving state policy goals Innovation Transparent and quick regulation process	Quality and reliable electricity Community engagement in the regulatory process is high Does not align utility incentives with policy goals Process needs to be quicker, more efficient, and more flexible	Could incentivize utility to meet policy goals Supportive of use of incentives and penalties Remove utilities incentive for capital investments Could reduce costs and give utility flexibility to meet goals Difficult to design and implement well and high potential for unintended consequences Metrics could include reliability, customer satisfaction, reduced rates, safety, environmental impact, social obligations, innovation, and employment beyond utility	HERA may increase independence with regards to grid reliability but would increase costs and is not a good fit An ISO would increase costs and would not work because the market is too small DSPP could expand deployment of DERs and allow for more innovation and competition but would require high up-front costs and would not work well Supportive of reduced regulation for co-ops

5.1.1 The City and County of Honolulu

Two meetings were held in the City and County of Honolulu, one in Kailua and one in Honolulu.[11]

5.1.1.1 **Honolulu**

The workshop was held at the Homer A. Maxey International Trade Resource Center Conference Room at the Hawaii Foreign-Trade Zone #9 in Honolulu. There were 17 participants.

5.1.1.1.1 Priorities for Stakeholders

The stakeholders discussed a multitude of priorities, with a particular focus on resiliency and reliability, listing the following as the most important issues:

- state renewable energy goals;
- local economic impacts;
- resilience;
- diversification to enable resilience;
- defense and resilience from hurricanes;
- power quality and reliability;
- storage to facilitate reliability;
- prevention of blackouts;
- enabling prosumers for reliability;
- grid access;
- consumer education;
- affordability;
- access to renewables;
- efficiency;
- innovation;
- microgrids;
- new technologies;
- fast adoption and easy on-ramps of new technologies; and
- less volatility.

5.1.1.1.2 Status Quo

The stakeholders explained that the status quo has resulted in high rates of solar adoption. They also discussed that service is safe and reliable, and that there is low volatility in electricity rates. A primary area for improvement was electricity costs. Stakeholders would like to see the current model improved by increasing grid access for IPPs, improving power quality, and increasing

[11] The VERGE Workshop was also held in Honolulu, but the summary is provided separately since there were participants at VERGE from across the state.

resilience to be better prepared for potential disasters. It was also explained that the current generation fleet is old and is in need of newer systems, particularly the faster adoption of renewable generation. There was the perception that HECO is "clinging to old assets" instead of investing in the grid. Additionally, stakeholders explained that the utility's website is not user-friendly and could be improved. Some stakeholders called the current model an "arcane regulatory model" that has not adapted to technologies and markets have changed and that it is not very resilient.

5.1.1.1.3 Small Group Discussion

Stakeholders felt that PBR seems very complicated but were supportive of it as a model that could provide flexibility and incentivize the utility to take actions in line with customer and policy priorities. Stakeholders liked the emphasis that PBR could put on continuous improvement over time and the potential ability community input to be included in the metric design. There were questions about how impactful PBR might be if only minor changes are implemented and interest in the adoption of more intense PBR components. Otherwise, some stakeholders were worried that it would not be much different from the status quo. There was concern that PBR could result in increased complexity and bureaucracy. For example, stakeholders questioned how the credit from solar generation would be delivered to the right person or entity. The stakeholders explained that designing PBR would require substantial expertise and that it would be difficult to avoid unintended consequences. It was mentioned that the PBR design should take into account what areas the utility can control versus what areas they cannot.

Stakeholders like the idea of being able to develop metrics in collaboration with the utility under PBR. They expressed interest in utility and transportation collaborations, GHG emissions, cost, and customer service as potential metrics. Stakeholders asked if PBR could be tied into the rate structure adjustments (e.g., rates that encourage efficient consumption, rates that achieve equity targets and benefit LMI customers).

Stakeholders were supportive of HERA as a model that would provide accountability, increased grid access, reliability, resiliency, and transparency. They questioned why HERA had not yet been adopted and also were not sure how HERA's role would differ from that of the PUC, stating that it could be redundant. There was support for the activities that HERA would theoretically undertake, but stakeholders wondered who was doing these now and, assuming that they are already being handled, wanted to know what the added costs would be to implement HERA, including potentially high upfront costs. There was concern that doing so would create another layer of bureaucracy. Overall, stakeholders were uncertain if HERA would solve the problems they identified in the status quo model.

There was support for an ISO as a model that would create more competition. However, stakeholders questioned if Hawaii's market was large enough for an ISO to operate. Stakeholders hypothesized that it could make more sense if there was a drastic expansion in the number of energy providers in the state.

Stakeholders were uncertain as to how the DSPP model would differ from the status quo. They wanted to understand how contracts would change under this model and how it would affect

service and reliability because the stability of power quality was a priority. There was concern that the DSPP model is more radical and that it would then inherently contain more risk.

In regard to lighter regulation for co-ops, stakeholders were supportive of this option, stating that KIUC should be rewarded for its successes and that Hawaii should consider regulation levels for co-ops that are similar to those around the country.

5.1.1.1.4 Other Topics

In general, there was a lot of discussion among the stakeholders about incremental versus radical change to the regulatory model. Some suggested that Hawaii should take bold and innovative steps as they explained that there is too much to lose if only timid actions are taken.

5.1.1.2 **Kailua**

The workshop was held at the Enchanted Lake Elementary School in Kailua. There were 7 participants.

5.1.1.2.1 Priorities for Stakeholders

The stakeholder's primary priorities were focused on increasing the deployment of and access to affordable renewables while increasing plant efficiency and ensuring an open and competitive market for generation. There was some interest in supporting the deployment of wave energy technology. There was also discussion about the need for continuous improvement by the utility and throughout the system. One stakeholder mentioned that HECO's parent company should divest its ownership of American Savings Bank to focus on the utilities.

5.1.1.2.2 Status Quo

The stakeholders explained that the current model ensures utilities provide reliable service. There was a lot of support for the PUC's focus on improving energy efficiency through founding Hawaii Energy, with some stakeholders highlighting the benefit of having Hawaii Energy as a separate entity from the utility. It was also discussed that the current model had encouraged the development of renewable energy. However, some stakeholders disagreed, saying that they would like to see increased support for the solar industry, renewable deployment for homeowners, and storage and microgrid projects. Stakeholders discussed how the current model sends the "wrong incentives" to the utility because it creates a financial incentive to invest in capital improvements and provides no incentives for securing generation from less expensive IPPs. Additionally, some stakeholders explained that they would like to see an increased focus on undergrounding lines. Stakeholders also mentioned that HECO is beholden to shareholders and that this is one reason why HECO continues to be reliant on fossil fuels.

5.1.1.2.3 Small Group Discussion

The stakeholders were mixed in their support of PBR. There was concern that, under PBR, the utility could face the risk of losing all profits and even take losses, which would result in layoffs. However, other stakeholders explained that the "possibility to fail" would be a good incentive to HECO and would ensure that HECO shared some of the risks. In general, there was support for

PBR as an option to increase efficiency in operations within HECO. The stakeholders briefly discussed potential metrics, including customer satisfaction, outage statistics, and distribution capacity improvements.

Stakeholders were supportive of the ISO model because it could increase competition but were concerned that it would also increase risk, variability, and price volatility.

There was some interest in the DSPP model. Stakeholders explained that HECO "belongs in the wires business" and that they should continue to be compensated for that work. They liked that the DSPP model could create a competitive generation market that would provide more opportunities for renewables to enter the market.

The stakeholders were supportive of reducing regulation for KIUC, explaining that KIUC has demonstrated its ability to manage and operate the utility well.

5.1.1.2.4 Other Topics

In general, stakeholders explained that they would need to see cost estimates for each model to provide a useful opinion on each of these models.

5.1.2 Hawaii County

Two meetings were held in Hawaii County, one in Kona and one in Hilo.

5.1.2.1 **Hilo**

The workshop was held at the Waiakea High School in Hilo. There were 5 participants.

5.1.2.1.1 Priorities for Stakeholders

Stakeholders identified many priorities for utility regulation, but the highest priority was reducing rates. Other priorities included increasing renewable energy deployment, improving utility and grid flexibility and resiliency, and ensuring that solutions are adapted to the needs of specific locations based on local needs. It was discussed that market competition, not politics, should be driving investment decisions. While there was a strong focus on increasing DERs, stakeholders noted that utility-scale renewables are less expensive than DER solutions and that DERs will not be the best and only solution for meeting the state's electric needs. Instead, stakeholders would like to see an appropriate balance between grid-scale renewables and DERs. Stakeholders also mentioned that the equity of electric costs must be considered as the LMI community will have to carry more of the costs to operate and maintain the grid as wealthier residents defect from the grid.

5.1.2.1.2 Status Quo

The stakeholders highlighted that the current model has resulted in reliable electricity. However, there was concern that the current policy environment is driven by politics rather than allowing for the market to identify the best solutions. Additionally, it was noted that the current way in which electric rates are set is too complicated for most people to understand.

There was an in-depth discussion about the concern that the current regulatory model does not include representation from each county in PUC decisions. The stakeholders suggested that any regulatory model should include a mechanism for increasing local representation in regulatory decisions. One option that was discussed included establishing a PUC body for each island to address island-specific topics and decisions.

5.1.2.1.3 Small Group Discussion

Stakeholders noted that different models might be more appropriate for different islands and that proposed solutions should address the contexts unique to each island. It was recommended that the analysis assesses how different regulatory models would work on each island, with particular consideration of how the demographics and income distribution may result in differences in the impacts of each model on specific islands. Stakeholders explained that the cost of electricity is a significant portion of monthly income for many households on the Big Island. Additionally, it was pointed out that policies like net energy metering shift the benefits to wealthier households and increase costs for LMI households by increasing grid operation costs borne by households that are unable to afford rooftop photovoltaics ("PV"), placing an unfair burden on community members that can least afford it.

Stakeholders liked the idea of PBR and using unique metrics for each island to ensure that community-specific goals were incorporated into the regulatory requirements for utilities operating on each island. It was noted that "carrots work better than sticks" and, therefore, the softer PBR options focused more on incentives were preferable to more stringent PBR implementation. It was suggested that the project team review literature on performance-based contracts in general (not specific to the energy sector) to identify which mechanisms (e.g., carrots, sticks, others?) are most effective at driving desired outcomes. Stakeholders stated that PBR would fail if grid defection rates continue to increase.

Potential metrics that the stakeholders discussed included:

- Equity
  Stakeholders explained that the Big Island has a high number of residents that are low- and moderate-income households. As such, equity of costs was a big concern, and stakeholders like that PBR metrics could be designed to encourage utilities to better address equity issues. It was discussed that metrics could ensure that the impacts of decisions are not borne primarily by LMI households and require that any decisions identify which segments of the community benefit and which bear the costs. Potential components of an equity metric identified during the discussion included setting levels for the percentage of household monthly electricity costs for each level of income (e.g., no household pays more than X% of income for energy; people at 80% of poverty level don't pay more than X% of income for electricity).

- Load stability
  Stakeholders explained that load attrition is a problem for the Big Island and that it could be beneficial for a metric to be established for how well the utility does at stabilizing and/or retaining load. There is a social benefit to load retention because costs of the grid are spread across more people.

- Cost stabilization
  For cost stabilization, the stakeholders suggested that metrics be designed around the percentage of monthly income that households pay for their electricity.

There was concern that the DSPP and ISO models would not work in Hawaii. For the ISO model to function in the state, stakeholders explained that it would require a separate ISO on each island and that the costs to do this would be very high.

Regardless of the regulatory model, stakeholders expressed that it must be designed to be flexible to address changing technologies quickly and that, as a result, adaptability must be a priority.

5.1.2.1.4 Other Topics

One stakeholder noted that the presentation and report should include PV vendors as stakeholders having a strong influence on policy adoption and regulatory proceedings. It was also suggested that the analysis includes scenarios with the high deployment of rooftop PV and microgrids and the impact that this would have on the grid.

Stakeholders explained that Hawaii County is unique and that any changes will have a major impact on the grid. Stakeholders explained that it is important to understand how the increased adoption of EVs will impact the grid under each model as EV adoption was identified as a "tipping point" for the grid that will be reached most quickly on the Big Island.

One stakeholder mentioned that, although co-ops are costlier to operate and are less efficient to operate than IOUs, KIUC has been able to secure more favorable power purchase agreements ("PPAs") than HELCO and that HELCO should remedy this.

5.1.2.2 **Kona**

The workshop was held at the Natural Energy Laboratory of Hawaii Authority in Kona. There were 5 participants, though primarily only 1 person actively contributed to the discussions.

5.1.2.2.1 Priorities for Stakeholders

The priorities for utility regulation in Kona focused on improving electricity resiliency and security, mainly from severe storms, and increasing renewable energy generation. The stakeholders discussed the need for utilities to be flexible as new technologies that prove beneficial to Hawaii County come to market. Additionally, the stakeholders stated that utilities should be responsive to customer needs and should view customers as potential partners in meeting energy demands.

5.1.2.2.2 Status Quo

The stakeholders stated that HELCO balances supply and demand well. However, it was expressed that the current ownership model is "broken" and does not meet the needs of the community. There was concern that the current regulatory model does not allow for the flexibility in policy required for utilities to adopt new technologies nor to respond quickly to changes. An

example provided was that the current policy for customers under net metering does not allow them to increase the size of their PV system while remaining under the net energy metering program. A stakeholder expressed that it would be beneficial for customers who have added an EV to be able to increase their PV system to offset the additional demand from their EV. Stakeholders mentioned that it would be beneficial to the community as a whole if regulations and policies increased incentives for customers to deploy renewable DERs that supplied energy to the grid. Additionally, stakeholders felt that the PUC is too cautious and weighs its decisions more toward the needs of the utility than of those that would increase clean energy deployment.

The stakeholders explained that any regulatory model must be customer-centric by prioritizing providing the best value to customers. Under the current model, HELCO is "slow and cumbersome," and does not operate in a manner that best meets the needs of customers. A model that would improve the utility's responsiveness to customers would be beneficial, and stakeholders suggested that HELCO look to KIUC's interactions with and responsiveness to their customers as a model to follow.

5.1.2.2.3 Small Group Discussion

Stakeholders expressed that regulation has one purpose – to protect the public interest. Any model that is adopted should do this and should not add costs to businesses nor stifle innovation. It was recognized that utilities need to make a profit but that they must also stay relevant to changing technologies. Stakeholders highlighted that any regulatory model that is used must address grid resiliency. There was concern that climate change will increase the number and severity of storms which will increase the operational risks to the grid. Increases in DERs, including microgrids and batteries, was proposed as a solution to improve resiliency

Stakeholders were supportive of PBR and increasing the link between utility revenues and performance but questioned why the current regulatory model does not already do this. For example, stakeholders explained that since the utility is currently required to meet the RPS requirements a PBR metric tied to renewable generation would be redundant. However, the stakeholders were supportive of the use of metrics that could be linked to goals with specific timelines as a way to drive utility action. Potential metrics discussed included progress toward RPS and increasing diversity of renewable generation. The stakeholders noted that with Puna Geothermal Ventures damaged by the volcano, HELCO would have difficulties meeting its RPS goals even over a longer horizon.

There was particular interest in two regulatory models: HERA and DSPP. Stakeholders expressed that HERA may be a good option as it could better drive HELCO to meet its RPS goals and liked that it could increase opportunities for access to the grid from non-utility players. However, there was concern that HERA may create redundancies and be inefficient.

Stakeholders described the grid as primarily a "giant battery," hypothesizing that the DSPP model may be the only relevant model in five years as the adoption of DERs is expected to increase rapidly as technology costs decrease. Unless the utility addresses this and identifies a path forward that meets customers' needs, stakeholders expected that grid defection would increase substantially as customers deploy combinations of DERs with batteries and microgrids. Blockchain technology was identified as a technology that will further enable contracts between

customers without the need for engaging with HELCO to provide generation. Grid defection was considered the worst-case scenario as it increases costs for remaining customers which are likely to be those least able to afford it.

Stakeholders pointed out that the more complex a regulatory model is, the more difficult it will be to manage well. Any regulatory model should be well thought out before implementation because the whole community will "pay for it" if a regulatory model is implemented incorrectly or in such a way as to result in unintended negative consequences.

5.1.2.2.4 Other Topics

There was concern expressed with how the current RPS allows non-renewable generation, like burning trees for fuel, to count toward the renewable portfolio standard ("RPS") obligations. It was suggested that this component of the RPS be reformed.

5.1.3 Kauai County

The workshop was held at Kauai High School in Lihue. There were 11 participants. The discussion at the Kauai workshop focused primarily on the impact of regulatory models specifically on KIUC. There was no discussion of stakeholder priorities.

5.1.3.1 Status Quo

Stakeholders pointed out that the current model has resulted in reliable electricity delivery. As stakeholders across the state, there was agreement that the PUC is overburdened and does not have sufficient resources to handle all of its activities.

5.1.3.2 Small Group Discussion

The discussion focused primarily on how lighter regulation would benefit Kauai, with little discussion of the other models with a few exceptions. The stakeholders were adamant that HERA would not work in Hawaii. They stated that it would be costlier to implement, would only increase bureaucracy, and would provide minimal benefit to the state. The stakeholders also did not think that the ISO model would be appropriate for Hawaii. There was concern that costs would be too high to implement a DSPP model. Overall, some stakeholders thought that market approaches do not address reliability issues efficiently and, therefore, do not provide good solutions.

The stakeholders pointed out that most co-ops on the mainland are not regulated or not regulated as heavily as IOUs. They provided the example of Michigan, stating that the PUC is involved only in territorial disputes and other minor issues as needed. Additionally, they noted that many co-ops on the mainland are not under RUS control. They would like to take what is working well on the mainland for co-op regulation and apply it to Hawaii.

Stakeholders did not think that the PUC is more responsive to community concerns than KIUC and questioned how non-elected PUC commissions would be more sensitive to community needs than elected co-op board members. They stated that the PUC only visits Kauai 4-5 times per year while KIUC leadership lives in the community, interacts with ratepayers daily, and receives feedback directly from the community members. Furthermore, they stated that the board is

responsive to community concerns, more so than the PUC has been. Board meetings are open to the public and community members regularly participate. Stakeholders stated that this sets them apart from the HECO Companies and is a main reason that PUC regulation is not as necessary.

Stakeholders explained that the current PUC regulation of rate cases was extremely costly for KIUC, saying that each costs millions of dollars. Additionally, they discussed how slow and burdensome the process is. As an example, they said that it took 6-9 months for the regulatory process in a recent solar case. They explained that these delays are expensive in a market that moves quickly. Another example that was provided is the community based renewable energy regulations under which KIUC is required to pay avoided cost of oil to solar projects even through that avoided cost is no longer relevant for KIUC.

The stakeholders felt that they are harmed by issues that are only relevant to the HECO Companies. They stated that the PUC is preoccupied with activities of the HECO Companies and cannot pay the necessary attention to KIUC which results in delays in rulings related to KIUC's issues. They provided an example of a case related to a cost of service study required by RUS that the PUC never approved and said that the process was a waste of resources for KIUC.

Stakeholders discussed the potential need for the PUC to provide dispute resolution services under a model with less regulation. Some stakeholders pointed to other co-ops where disputes are resolved through board elections and explained that, currently, only 250 signatures are needed to force a membership vote for issues that the board has decided on. This has happened twice in the history of KIUC and both times the membership voted to support the board's decision. Stakeholders explained that this threshold is very low and that they would like to see the number of signatures increased because it is expensive to hold a vote. Stakeholders pondered if there could be a role for a petition that could be a middle ground between a casual conversation with the board and doing a full membership vote.

Stakeholders felt that KIUC is more transparent than other co-ops and did not see a need for the PUC to be involved in mandating transparency. That said, they also explained that they were not concerned with the PUC's requirements about what information is made public as they would make this information public regardless.

The stakeholders did not agree with the idea that lighter regulation would result in a loss of revenue for the PUC, stating that it would reduce costs by reducing work for the PUC.

Overall, the stakeholders were very supportive of lighter regulation and were also open to an evolution of regulation over time. One stakeholder expressed that a model may work where the PUC was involved in fundamental issues, such as interpretation of a law, but where economic regulation was left up to the co-op's board. Others stated that they might be supportive of some type of "show-cause regulation" where the PUC would intervene if rate increases, or investments, surpassed a certain threshold or on specific issues as requested by stakeholders. The stakeholders agreed that they would like the PUC not to be involved in ratemaking for KIUC.

5.1.3.3 **Other Topics**

The stakeholders pointed out the importance of understanding the cultural differences between Kauai and the rest of Hawaii. Due to their relatively small size, they felt that their issues are

ignored at the state level. However, they suggested that Kauai should be viewed as an example of what is working well.

5.1.4 Maui County

The Project Team held three meetings in Maui County, one each on Maui, Molokai, and Lanai. The summaries below are separated by meeting.

5.1.4.1 Lanai

The workshop was held at the Lanai Community Center in Lanai City. There were 6 participants.

5.1.4.1.1 Priorities for Stakeholders

The stakeholders expressed a strong preference for a model that would ensure the utility is responsive to community needs and that the utility incorporates community input into decisions. In combination with this, the stakeholders placed a high value on ensuring that there is a personal relationship between the utility and community members on the island, including those that provide energy through the use of DERs.

Another priority discussed was keeping fuel costs and, as a result, rates from increasing. The stakeholders mentioned that incentives to expand deployment of DERs by individuals and entities that own rentals (primarily Pulama Lanai's properties rented to employees) would benefit the island as a whole and individual household by reducing monthly electricity costs. They explained that increased adoption of DERs would act as a hedge against future increases in fuel costs.

5.1.4.1.2 Status Quo

The stakeholders explained that the status quo works well, that service is reliable, and that MECO maintains a personal relationship with the community. However, stakeholders expressed that the current model does not address all of the community's priorities. For example, the stakeholders would like to see a greater focus on keeping rates low for customers. Additionally, they would like to see an increase in incentives for rooftop PV and renewable energy in general and perhaps requirements for Pulama Lanai to install PV on employee rental properties. The stakeholders questioned why the fuel delivery costs are so much higher for Lanai than for the other neighbor islands and would like to see more equality in these costs.

In general, stakeholders were supportive of the PUC as an entity that ensures utilities operate in the best interests of Hawaii's citizens, and they see this as an integral role. They noted that the consumer advocate does not accurately represent the interests of the community on Lanai as it represents the state's interests broadly. The stakeholders explained that this has resulted in issues relevant to Lanai being dismissed.

5.1.4.1.3 Small Group Discussion

In general, the stakeholders were supportive of implementation of the PBR model as they felt that the use of metrics would be a beneficial way to ensure that community needs are incorporated

into utility decisions. There was more interest in incorporating PBR metrics into the status quo as a method to modify the current regulatory model rather than implementing a major overhaul of the current model. In discussing potential PBR metrics, the stakeholders mentioned:

- generation efficiency;
- transmission efficiency;
- costs;
- reliability;
- upgrades to the transmission and distribution system, particularly in coordination with long-term planning;
- time to restore power after an outage;
- increased resilient supply of oil and reduction in dependency on oil;
- environmental impacts/benefits including increased deployment of renewables and mitigation strategies related to the potential effects of oil delivery and storage (e.g., oils spills and leaks, both in land and in the harbor); and
- resiliency planning, including strategies to mitigate system impacts if the infrastructure in the harbor in Lanai or Oahu is damaged and the barge is unable to deliver oil to Lanai for an extended period.

The stakeholders stated that the development of metrics must be conducted by entities within Hawaii and that it would be best if representatives from Lanai were involved in the process. They do not want the metrics developed by an entity outside of the state.

There was concern that the HERA, ISO, and DSPP models would not work on Lanai and would not work well for MECO. Specifically, it was noted that the market is too small on Lanai for these models to work well. Along those lines, stakeholders were united in stating the importance that any model must ensure that the current MECO staff on Lanai remain employed.

Regardless of the regulatory model in place, the stakeholders stated that any potential projects must consider and minimize environmental impacts and that the siting process must include a detailed environmental review.

Stakeholders pondered if it would be possible and beneficial to mix components of different models into a hybrid model that would best address Lanai's unique contexts. Additionally, they pointed out that they would like the analysis to consider how each model might result in increased employment opportunities on Lanai.

Stakeholders strongly expressed that the control of the regulatory model must be based in Hawaii and should not be managed by an entity outside of the state. Additionally, it was discussed that it would be preferable for there to be representation from the Lanai community on the regulatory body. Stakeholders discussed options for achieving sufficient representation, including having a resident of Lanai as an active member on the PUC. There was concern that an outside entity would be hired to implement and operate HERA or an ISO resulting in a loss of local control in regulations.

5.1.4.1.4 Other Topics

It was noted that Lanai is too small for a co-op ownership model to work well and cost-effectively.

The topic of Community-Based Renewable Energy was discussed, and stakeholders expressed an interest in the state working to make sure that this is implemented successfully. In relation to this, one stakeholder mentioned that Pulama Lanai is required through the community planning documents to develop a light industrial facility or area on Lanai but that it has not moved forward with this. The stakeholders identified this as a potential opportunity for Pulama Lanai to build a project under the Community Based Renewable Energy program.

The stakeholders encouraged the project team to consider that Lanai is unique and that this will mean that each model will have a different impact on Lanai than on the other islands. The stakeholders pointed out that one unique thing about Lanai is that the majority of the island is owned by a single entity. It was highly recommended that the project team engage Pulama Lanai to understand how any model would impact Pulama Lanai's operations on the island. As the primary land owner and primary energy user, stakeholders stated that any model must work for Pulama Lanai. Otherwise, Pulama Lanai may consider grid defection which would have a hugely negative impact on Lanai's grid and electricity costs.

5.1.4.2 **Maui**

The workshop was held at the Waikapu Community Center in Wailuku. There were 12 participants.

5.1.4.2.1 Priorities for Stakeholders

Overall, stakeholders prioritized a valuable and resilient grid that would allow Maui to achieve independence from oil. The stakeholders stated that they would like to see an increase in renewable generation but would like to do so at the lowest cost. To enable this to happen, they would like the interconnection process to be simplified and for the utility to be responsible for providing the necessary upgrades to allow for an increased renewable generation instead of new generators being required to do this. Grid modernization was listed as a priority, but stakeholders want to make sure that it is implemented correctly. In line with grid modernization, they would like for the deployment of storage to be optimized.

5.1.4.2.2 Status Quo

Stakeholders explained that one benefit of the current model is that everyone understands how the model works and the associated processes. The stakeholders agreed that the current model has resulted in reliable electricity and that the utility fixes outages and other issues quickly. Additionally, under the current model, the utilities have been forced to learn how to modify their operations to incorporate the adoption of a substantial amount of rooftop solar with minimal utility investment. The stakeholders highlighted that the PUC's independence is integral to its success and that this has worked well under the current model. The current model is seen as motivating regulators to act in a way that best serves the public good.

Stakeholders would like there to be an improved community engagement process. Currently, they see a need for the HECO Companies to be required to increase the involvement of stakeholders in the working group and other discussions and that stakeholder input influences

utility decisions. They would like the HECO Company's working groups to influence change. Under the current model, the stakeholders view the working groups as more of a formality and the stakeholders do not think that the utility is listening to the community input. Additionally, it was recommended that greater efforts be made to bring a broader representation of community interests into the process as engagement is primarily focused on those involved in the energy sector.

The stakeholders also discussed the concern with how the current model does not address the cost shift and inequity problems associated with grid defection. For example, the grid was built to supply electricity to everyone but, with grid defection, the costs to maintain the grid are being borne more heavily by LMI households that are unable to afford their own PV system. This inequity will continue to increase as grid defection increases and must be addressed. It was noted that affordable housing is a primary concern for Maui and stakeholders would like to understand how this issue is being included in the analysis of regulatory models. Stakeholders explained that this cost shift is a serious issue and that, under the current model, it is not being addressed.

The current regulatory process is seen by stakeholders as biased toward supply-side solutions. They would like for the regulatory model to incorporate better and value the benefit of demand-side solutions.

5.1.4.2.3 Small Group Discussion

When discussing potential models, it was pointed out that the adoption of new models would not necessarily replace the current model. Stakeholders noted that any changes to the regulatory model and subsequent requirements placed on utilities must be equitable and must function for everyone.

Due to the recent legislative and PUC actions, the stakeholders viewed PBR as a "foregone conclusion" but recognized that there are many variants related to PBR implementation and the potential existed for it to be adopted with components of other models being considered in this analysis. Stakeholders noted that the current model incorporates elements of PBR already, including the regulatory lag. There was concern that there will be unintended consequences related to the adoption of PBR, mainly based on how the metrics are defined. PBR was viewed as a solution to one problem (better aligning utility profits based on performance), but there was concern that PBR is being discussed as the solution to all of the state's energy problems. For example, stakeholders explained that is unclear how PBR will address equity issues or integration of EVs and other technology innovations that will require a grid that operates differently than it has in the past.

Stakeholders noted that the implementation of PBR would likely require revisions within the PUC itself. For example, there would need to be additional staff with the necessary experience to implement PBR. Additionally, the PUC's software systems would need to be updated, notably to allow for the required increased data sharing under the legislative requirements. Stakeholders questioned whether or not the PUC has the capacity to do this.

There was concern that any metric considered for inclusion under PBR would be politicized and that it will be difficult for an agreement to be reached regarding metrics and implementation in

general. Stakeholders discussed that performance metrics should incentivize the utility to move toward relying more on technological or platform solutions to operate their grid rather than on capital-intensive approaches. One stakeholder mentioned the Federal Communication Commission's spectrum auction as a potential example to follow when creating an auction for DER under PBR.

Stakeholders mentioned that there are many similarities between an ISO and HERA. Stakeholders disagreed about whether or not HERA would solve any problems. While some did not think that it would do so as the utility is currently responsible for maintaining the grid, others explained that HERA would set a standard for the utility to follow and result in more cost-effective infrastructure investments. For example, a stakeholder explained that utilities would be unable to adjust reserve margins in order to justify more capital investments. There was concern that IPPs would have increased responsibilities for maintaining the grid under HERA. The impartiality of HERA was seen to be beneficial as stakeholders explained that it is currently difficult to determine the cost to connect to the grid which has resulted in distrust of how the utility is assessing the costs.

When discussing an ISO model, stakeholders explained that any implementation of an ISO in Hawaii would be very different than implementation on the mainland. Stakeholders asked if anything would be much different under an ISO since there would still be a single vertically integrated utility. It was questioned if an ISO provides a solution on Maui where there are thousands of small generators, not thousands of utility-scale generators like on the mainland. It was also noted that ISOs typically operate at the transmission level when one would need to operate at the distribution level in Maui due to the amount of DERs. Stakeholders discussed that an ISO would just manage grid access and dispatch, some of which HERA could address. Stakeholders were supportive of the increased equality in dispatch control that an ISO would bring to the system.

Regardless of model, the stakeholders would like to see increased impartiality when it comes to the integration of DERs into the system. Stakeholders recommended that the analysis consider how different regulatory models would work with varying models of ownership. They would like to understand if different regulatory models are more suitable with varying models of ownership and if different regulatory models would be more appropriate on each island.

It was brought up that some of these models may make more sense if the islands were interconnected, particularly by increasing the economies of scale. Stakeholders discussed that although interconnection is still in HSEO's plans, both the current governor and potential future governors are against it.

5.1.4.2.4 Other Topics

Stakeholders discussed the need for there to be coordination between the legislative, regulatory, and administrative processes in relation to this topic. It was perceived that the legislature passes bills without having done the necessary due diligence regarding analysis or coordination with other government entities. Stakeholders viewed this inconsistency in actions as unlikely to result

in practical and successful implementation. Consistency from the legislature over multiple years was considered to be more helpful in supporting the PUC's implementation of policy.

There was interest in increasing the use of non-wires alternatives and better understanding how to create and leverage these opportunities throughout Maui.

One stakeholder recommended that the project team increase stakeholder outreach to discuss these options with stakeholders representing broader interests on Maui as it seemed that most stakeholders participating in the meeting were formally engaged in the energy sector. Similarly, there was concern that this lack of representation from the broader community would result in a backlash against any recommendations from the analysis.

It was brought up that people who defect from the grid are seen as acting nobly even though their actions have a negative impact on others who now must pay an increased share for maintaining the grid.

5.1.4.3 **Molokai**

The workshop was held at the Mitchell Pauole Community Center in Kaunakakai. There were 12 participants.

5.1.4.3.1 Priorities for Stakeholders

The primary priority for stakeholders was keeping electricity costs as low as possible. There was strong agreement among the stakeholders that the community should be involved in utility decisions and involved from the early stages of any potential project or planning process. The community would like to have more options and more control over the costs of electricity. Additionally, there was interest in increasing distributed generation as a way to both lower costs and increase community ownership in electricity generation.

Many stakeholders mentioned extreme concern with the utility's lack of a public bidding process for generation projects with specific mention of the Half Moon Ventures project. They would like to ensure that there is a robust public bidding process which enables competition and allows the community an opportunity to provide a proposal and to provide input on project selection.

The stakeholders identified both efficient operations and system-wide/island-wide efficiencies as a priority area for any regulatory model to consider. For example, it was discussed that there might be opportunities to coordinate operations of multiple systems (e.g., water, agriculture, economic development) across the island to maximize efficient use of resources more cost-effectively than considering each system individually.

5.1.4.3.2 Status Quo

In general, the stakeholders did not feel that the current regulatory model aligns well with community priorities. However, there was recognition that the appliance replacement program that MECO operates is well run and provides a benefit to the community.

The primary concern with the current regulatory model was focused on the procurement process and that it does not require the utility or PUC to include a stakeholder review from residents on Molokai for any potential projects, regardless of size.[12] The stakeholders would like to see a drastic improvement in the amount of engagement that local residents can have in the review of and decision making related to all projects. It was pointed out, however, that MECO has improved their engagement with the community. The stakeholders were appreciative of this effort and the opportunity for their input to be considered in the utility planning process. It was suggested that a possible solution would be for the PUC and utility to consult with either the County Council or Molokai Planning Commission on any potential projects.

Additionally, stakeholders would like to see a model that increases the use of and diversity of renewable energy projects, including pumped hydro as a method for storing renewable generation for dispatch as needed and use of landfill gas for electric generation. It was stated that all projects should consider the long-term sustainability and cost of projects and they would like to see the utility consider making system upgrades rather than building new generation as that might be a more cost-effective option over the long-term.

5.1.4.3.3 Small Group Discussion

The majority of the small group discussion focused on the characteristics of an ideal regulatory model rather than on each specific model being assessed for the study. There was strong interest in understanding which model(s) would result in the greatest economic development for Molokai. The stakeholders were supportive of unused or underutilized land being put to productive use in coordination with creating jobs for residents. One example discussed was the creation of a hibiscus farm that would provide long-term, sustainable jobs for the community. Stakeholders wondered if it would be possible to identify similar solutions for renewable generation projects.

Stakeholders asked which model would be most inclusive of small communities and suggested that any model include a formal process requiring any PUC regulated entity to implement a community engagement process. They would like to see a model that includes a formal process for community input. For example, the stakeholders suggested that there could be an advisory group established under any model which would include representatives from each island. There was concern that a single entity would be selected to represent Molokai's interests and that it would be preferable to have multiple representatives from Molokai no single entity could accurately represent the community's diverse interests. They felt that the Community Plan should be used as a guide for potential projects and that the County Council should be involved in all discussions about potential projects at an early stage and throughout the entire discussion. They expressed concern that there is the potential for corruption under any model and, without

[12] The current regulations stipulate that the utility does not need to conduct a competitive bidding process for procurement of generation if the net output available to the utility is 1% or less of a utility's total firm capacity (see page 4 of HPUC Docket 03-0372, Decision and Order No. 23121, available at http://files.hawaii.gov/dcca/dca/dno/dno2006/23121.pdf).

sufficient local representation, it would be difficult to trust that the community's best interests were being considered.

Regardless of the model, stakeholders explained that it is imperative for it to ensure that Molokai residents can provide input on RFPs and that they have the opportunity to submit proposals through a competitive bid process. They would like local economic benefits such as job creation to be included as a factor in project evaluation.

The stakeholders stated that any model must ensure that environmental and cultural concerns are incorporated in the assessment of potential projects. They would like all utility projects to be required to complete a "full environmental review" and a Programmatic Environmental Impact Statement.

The stakeholders would like to see the regulatory model encourage and support the creation of creative partnerships to develop solutions. They also highlighted that any model must include a mechanism for assessing any potential project or decision based on the impact that it will have on future generations.

There was interest in increasing the diversity of renewable energy generation across the island and supporting the development of smart grid technology. The stakeholders were interested in understanding how each model would address this.

In general, there was interest in PBR as a model that would allow the community to have more opportunity to drive utility decisions and ensure that they are in line with the community's goals. They would like to see metrics addressing reducing rates, improving grid infrastructure, and maximizing the community's benefit from any investment while balancing the benefits of grid maintenance with increased generation. The stakeholders questioned who would establish the goals under the PBR model and reiterated that Molokai residents must be involved in the process.

One stakeholder mentioned that an ISO would not work on Molokai as the market is too small for this model.

When Hawaii's community-based renewable energy program was brought up, stakeholders expressed interest in learning more about options and how a project under this program could increase the opportunity for more direct community participation in generation. Additionally, they would like to see a program that resulted in the installation of solar hot water systems on every resident's property.

5.1.4.3.4 Other Topics

The stakeholders explained that they do not like it when organizations (e.g., consultants, developers, and the utility) present them with a solution. Instead, they would like to be involved in the process of identifying and assessing potential solutions from the beginning. Additionally, one stakeholder expressed concern that the state hired an out of state consultant to conduct this study when it would be better to have an in-state company with connections to the community conduct the analysis. The stakeholders recommended that additional outreach be held before the community meetings to ensure more people are aware of the meetings, and suggested advertising

in the local newspaper, speaking with the county council and Molokai Planning Commission, and perhaps even having meetings in each district on Molokai instead of only in Kaunakakai.

One stakeholder mentioned that microgrids would be a good solution for Molokai and that they would like to see microgrids developed on the island.

There was some interest in a co-op ownership model, but stakeholders noted that it would not work for Molokai if the community had to start out in debt.

The stakeholders strongly expressed concern and anger about the Half Moon Ventures project. In general, there was frustration that MECO was not required to conduct a competitive bidding process for the project, that the community was not consulted, and that it would not be the best use of Hawaii's GEMS financing program.

5.1.5 VERGE Workshop

The VERGE Workshop was held at the Hilton Hawaiian Village in Honolulu. There were more than 100 participants.[13]

5.1.5.1.1 Priorities for Stakeholders

The stakeholders identified the following priorities:

- reliability/stability;
- achievement of state policy goals such as the RPS, but potentially others;
- reducing rates;
- innovation and openness to the adoption of new technologies;
- equity between customer classes;
- transparency, including improving public awareness and understanding of the regulatory process;
- ensuring rate design has appropriate incentives;
- grid resiliency;
- improving the speed of the regulatory process;
- providing a framework for investment; and
- implementing a model that will function in an island context.

5.1.5.1.2 Status Quo

Under the current model, stakeholders expressed that the quality and reliability of electric service is good. It was felt that the PUC communicates well with the utilities about dockets and that

[13] Very few of the participants signed in at the VERGE workshop.

consumer engagement in energy issues is high as both the PUC and utilities have improved transparency and public outreach.

Stakeholders noted that the PUC is already incorporating some elements of PBR that incentivize the adoption of renewable energy (e.g., competitive bidding, decoupling, etc.). However, they expressed that the current model does not generally align the utilities incentives with policy goals.

The primary improvement needed as identified by stakeholders was the speed and efficiency of the regulatory process as it is considered to be too inflexible. In general, stakeholders would like to see the regulatory process revised to ensure that utilities are better meeting the priorities identified above in 5.1.5.1.1. Other improvements included using a "holistic approach" and being more results-focused. However, there was conflicting input on whether there should be more or less oversight by regulators.

5.1.5.1.3 Discussions on Models

5.1.5.1.3.1 HERA

Many stakeholders did not see HERA as a good fit for Hawaii and questioned its necessity. However, some mentioned that it would provide a layer of independence in regards to reliability and may improve or complement the regulatory process. In general, stakeholders saw HERA as adding unnecessary costs and complexity to the regulatory framework and stated that it would be redundant. There remained uncertainty about how HERA would work and what implementation costs would be.

5.1.5.1.3.2 ISO

The majority of stakeholders did not think that it would be beneficial to adopt an ISO model in Hawaii. However, they noted that it could be more efficient in terms of time and costs if markets could be established and would provide more opportunities for stakeholders outside of the utility. Someone also pointed out that an independent entity may have a better rating than the HECO Companies. In general, stakeholders explained that adoption of an ISO would increase costs and bureaucracy. Overall, it was thought that an ISO could not work in Hawaii because it is too small, and each island is a separate grid.

5.1.5.1.3.3 DSPP

Stakeholders discussed that this model could result in an increase in DER deployment and customer choice and were supportive of the potential for growth in innovation and competition under this model. However, they were concerned that the high up-front costs to establish this model and the market depth needed for it to operate well makes it a poor choice for Hawaii. Some stakeholders explained that this model could result in lost opportunities on transmission and generation optimization. There was general uncertainty about how this model would work, with stakeholders posing the following questions:

- Would all customers be served?

- Would we lose control over managing the grid?
- Would risk increase for investors?
- Would the system be fully reliable?

5.1.5.1.3.4 PBR

Overall, many stakeholders were supportive of the adoption of PBR as a way to augment the existing system. They saw the model as a way to encourage innovation and align utility actions with state policy goals. Many stakeholders liked the use of incentives and penalties as a way to help utilities to take specific actions and as a way to hold them accountable if they do not meet the goals. The stakeholders saw an earnings sharing mechanism ("ESM") as a way to align the utility's actions with policy and consumer goals.

Additionally, it was noted that some components of PBR are already in use in Hawaii and that there is a precedent for this type of model. The stakeholders were supportive of PBR as a way to remove the utility's incentive to increase capital investments and saw this as a path for reducing costs and giving the utility greater flexibility in meeting targets. Stakeholders liked the idea of capping utility prices or revenues as because of the rate certainty it would provide to customers and that it would encourage the utility to be more efficient. The model was seen as a way to increase utility flexibility and, if done correctly, reduce costs.

There was concern that there is not a single PBR model that works well for every location and that example models from other jurisdictions will not work in Hawaii's unique situation. Stakeholders pointed out that it is difficult to forecast correctly and would, therefore, be difficult for regulators to design PBR successfully. Many stakeholders mentioned the potential of perverse incentives and negative consequences if PBR is not designed carefully. There was concern that it will be difficult to design penalties fairly and such that they do not penalize the utility for areas outside of their control. Similarly, it was expressed that it would be challenging for a rate or revenue cap to be set at the appropriate level without leading to unintended consequences. Stakeholders wondered if an ESM would reduce the utility's incentive for investing in longer-term projects, and that this would result in higher costs for customers in the future. Some stakeholders explained that removing the utility's incentives for capital investments may make it more difficult for the utility to access capital and, therefore, be riskier than the status quo.

There was also a lot of uncertainty about how PBR will be designed and implemented, particularly regarding incentives.

Potential metrics discussed by stakeholders included:

- reliability and availability;
- customer satisfaction (could cover cost, accountability, and reliability, data and education);
- lower prices;
- safety;
- environmental impact;
- aligning with social obligations;
- innovation;

- aligning utility and customer incentives;
- consider impacts on employment in other sectors besides energy; and
- general discussion that it would be useful if PBR could result in broader positive implications across the economy.

In general, there were questions about how PBR would be implemented. For example, someone asked if it would make sense to do a pilot study, others discussed if it would be scaled up over time, and there was interest in more information and education being provided to the public surrounding PBR.

5.1.5.1.3.5 Lighter Regulation for Co-ops

Stakeholders were supportive of lighter regulation for co-ops because unregulated co-ops work well in other parts of the country. They saw reduced regulation as a way to streamline the co-op's processes, reduce costs, and give KIUC the ability to make decisions more quickly. There was a concern, however, that lighter regulation could lead to higher rates and an inability of the state to ensure co-ops to comply with state policy goals. Stakeholders explained that ratepayers would have no recourse aside from judicial action if the co-op is not taking appropriate measures in line with the ratepayers' interests. Some also brought up that this could result in differences in utility processes and policies on different islands which would make it more difficult and costlier for developers that work on multiple islands.

5.2 Bilateral Discussions

The teams conducted multiple bilateral meetings during the two weeks, as listed in Figure 15, meeting with 19 individuals representing counties, utilities, non-profits, state and local elected officials, and the private sector. The comments are compiled by themes in the list below. They are not attributed to a specific individual or organization.

Figure 15. Bilateral Meetings

	Team 1	
	Island	**Organization/Individual**
12-Jun	Oahu	Hawaii Solar Energy Association HECO Management Rep. Nicole Lowen
13-Jun	Oahu	City and County of Honolulu Lorraine Akiba, Former PUC Commissioner Randy Iwase, PUC Commissioner Rep. Chris Lee
14-Jun	Oahu	Carl Caliboso, Former PUC Commissioner Distributed Energy Resources Council Elemental Excelerator Ulupono Initiative
15-Jun	Kauai	County of Kauai Hermina Morita, Former PUC Commissioner
	Team 2	
	Island	**Organization/Individual**
21-Jun	Hawaii	County of Hawaii Hawaii Island Energy Cooperative

The comments from the bilateral meetings are summarized and combined by the topics below.

5.2.1 Priorities

Improving the interconnection process, reducing the time to interconnect, improving interconnection transparency, and reducing interconnection tariffs are priorities for the DER industry. Though it has improved slightly, they feel the process is still too long and impacts project economics. It is not only the utility process that is causing delays, but also the municipal permitting process. The informal interconnection process varies across the HECO Companies and is entirely different for KIUC which makes it difficult for companies that work on multiple islands, increasing the cost of interconnecting. It would be beneficial for the process to be consistent across all utilities. Additionally, the solar market on Kauai is only open to a small number of on-island companies.

Affordability and cost control, in general, were mentioned by many stakeholders with some stating that these are the number one priorities, even before meeting RPS goals.

Multiple stakeholders highlighted the importance of improving resiliency. Resilient electricity supply is critical however it is not efficient for a utility to have excessive redundancy in place (e.g., it was questioned if HELCO has had too much redundancy since the utility has explained that they will not have any supply disruptions with PGV being closed). It may be more cost-effective to have smaller, more diverse generation sources providing redundancy. Innovative

ways should be explored to achieve reliability rather than building massive amounts of additional capacity.

Utility customers want the ability to develop their own generation projects that increase their resiliency and, for some, reduce their greenhouse gas ("GHG") emissions.

For customers that have public policy goals, they would like to see a regulatory structure that enables them to meet these goals.

5.2.2 Status Quo

Some stakeholders explained the current regulatory model is working well. They felt that the legislature has been proactive in establishing a clear policy and the PUC has taken this direction seriously. Additionally, the PUC has been open to stakeholder engagement in dockets. The current model is seen as providing benefits and efficiencies with a single body (the utility) operating the entire system. There was concern that models which separate some components of grid management will be less efficient.

Stakeholders expressed frustration with the lack of local control in the decision-making process. All of the decisions impacting the electricity system are seen as being made in Oahu, via the legislature, PUC, or the HECO Companies. Due to the balance of power, stakeholders explained that representatives from Honolulu have the majority and can dismiss the interests of the neighbor islands.

There was concern that the current model is not transparent in how and why utilities and the PUC are determining which renewable projects are approved. For example, the PUC has approved large solar with higher costs than compared to distributed solar projects. Stakeholders would like to see the process conducted in a competitive, transparent manner like what the PUC did with energy efficiency.

Multiple stakeholders stated that the PUC is understaffed and does not have sufficient resources to operate. Additionally, it was mentioned that the PUC plays many roles and has similar responsibilities to the North American Electric Reliability Corporation ("NERC"), an ISO or regional transmission organization ("RTO"), and a PUC at the same time. One stakeholder suggested that interconnection studies could be outsourced to improve the speed of interconnection. Another stakeholder highlighted the importance of having consultants as independent investigators, facilitators, and working groups to support the PUC.

Multiple stakeholders explained that the interconnection process is too slow and cumbersome due to the utilities' operations. However, some stakeholders mentioned that it has improved, and that technical concerns with interconnection have arisen first on Maui but will be delayed on Oahu as the grid is more robust.

There was concern that the necessary data is not currently tracked. For example, data on the process for interconnecting (i.e., the time from interconnection application submittal to connection to the grid), capacity provided by renewables, and DER data are not currently tracked

sufficiently. It was recognized that this data would need to be tracked for implementation of many potential regulatory changes.

The HECO Companies are seen as difficult to work with, and there was interest in understanding how different models could move the utility to operate more of a service model. One stakeholder suggested that there needs to be a cultural shift where the utility proceeds to operating more like a technology company than a government-like organization.

Some stakeholders explained that there is no dedicated focus on driving innovation in the current model and that the utility should be required to have an innovation budget, not just an R&D budget.

5.2.3 HERA

Some stakeholders saw this model as redundant with the ISO model, and one stakeholder questioned if HERA would truly be able to remain independent. Stakeholders speculated that HERA had not been implemented for two reasons: first, because the legislation does not mandate its implementation and, second, because the PUC put other utility issues on hold while the NextEra acquisition docket was being considered.

One stakeholder highlighted the value that HERA would provide by ensuring a competitive framework for interconnection that does not favor the utility and, therefore, leveling the playing field for non-utility players. It was noted that the PUC does not currently have the technical ability nor resources to implement HERA but that it could potentially be operated as a small office with funding from the PUC. To be performed well, stakeholders noted it would require strong support from PUC commissioners.

5.2.4 ISO

One stakeholder commented that an ISO does not make sense for Hawaii.

5.2.5 DSPP

Some stakeholders expressed interest in the DSPP model. For example, stakeholders that work in the DER industry explained that this model might be preferable because it would increase deployment of DERs. Other stakeholders expressed that this model seems to create a lot of opportunities to incorporate electric vehicles, on-bill financing, and other options. There was some who valued that this model would allow for small customer-to-customer based transactions.

5.2.6 PBR

In general, stakeholders were supportive of PBR. Stakeholders viewed PBR as a way to better balance the risks between the utility and the ratepayers. There was support for reducing or eliminating utilities' motivation for increasing capital expenditures and breaking the link between capital investments and rates. Additionally, stakeholders viewed PBR as a way to align the shareholder values with policy and community goals. PBR was seen as a good option for this, especially in light of rapid changes in technology and the unique issues that pertain to a primarily

rural state. It was suggested that PBR could be designed to increase the penetration of DERs. However, it was noted that it would be beneficial if it could also address issues associated with rate design and the inequities created in the cost shift associated with DERs.

There were many topics related to PBR discussed during the bilateral meetings, and they are summarized by category below.

5.2.6.1 Design and Unintended Consequences

It was recognized that PBR is a complicated topic and that the "devil is in the details" when it comes to design and implementation. While there will inevitably be some mistakes made in implementing PBR, stakeholders explained that the PUC could not afford to make enormous errors as it would be extremely costly to the ratepayers. As the timeline for implementation is relatively quick, some stakeholders felt that it is more critical for the PUC to implement PBR correctly than to meet that timeline. Additionally, stakeholders strongly expressed concern that there will be unintended consequences if PBR is not implemented through a well thought out process. To prevent this, it was recommended that PBR not be designed to be too rigid in the initial years and that it be implemented through incremental changes over time. It was noted that PBR implementation should recognize what the utility does and does not have control over. For example, the utilities do not have complete control over the permitting process and issues like local opposition impede project development.

5.2.6.2 Breadth of Regulatory Change

The interest in the amount of regulatory change varied across stakeholders, with some preferring moderate and incremental changes and others preferring more revolutionary change. Some saw PBR as a good first move toward implementing changes to the status quo. Others discussed the potential for gradual evolution or using "shadow rates" to incrementally perform PBR. A broad change in regulation was seen to be unlikely by the 2020 timeline, and it is expected that PBR adoption will look more like modifying the current regulatory model.

Stakeholders noted that the current model already incorporates some components of PBR, including the earnings sharing mechanism (e.g., the HECO companies are required to share benefits of the lower tax rate after recent tax reforms). Performance incentive metrics ("PIMs") are also included, and it is unclear to some stakeholders if expanding PIMs would be sufficient to accomplish the goals of the legislature or the PUC docket in regards to PBR.

5.2.6.3 PUC Resources

Many stakeholders were concerned that the PUC does not have the staff or financial resources to successfully develop and implement PBR.

5.2.6.4 Financial Impact on Utility

There was concern expressed about how the PBR legislation was written without regard for financial markets or the potential impact on the HECO Companies. Stakeholders mentioned that the legislation created substantial concern for investors, but that the docket provided a calming effect as it more thoughtfully considered the issues and implementation of PBR. It was pointed out that the HECO Companies have a BBB- rating and that implementing PBR, primarily if it is

poorly designed, could result in credit rating companies downgrading the HECO Companies which could destroy the utility.

For PBR docket, it is important to understand how different designs that are being considered would impact utility finances. The utility's capacity for debt is essential, not just its annual income. Regardless of the regulatory model, the HECO Companies will have a fundamentally similar capital model which focuses on institutional investors. While a utility in a larger area could reposition itself as a growth opportunity expanding into new markets to attract different investors, the HECO Companies have no potential for growth and will always be a small utility. It is necessary to maintain a reasonable amount of dividend growth to ensure institutional investors remain interested. The dividend growth could be reduced, but it must stay attractive to the pension fund market.

5.2.6.5 **Implementation Elsewhere**

One stakeholder felt that there is a lack of experiential data on PBR implementation and, therefore, little understanding of what has worked well and what it costs to implement.

Stakeholders felt that New York's Reforming the Energy Vision would not work in its pure form in Hawaii. However an "impure" form could work. Stakeholders explained that it would be fine to rate base grid improvements, but that fuel costs would need to be reduced, or the LMI customers will bare increasing costs as wealthier customers defect from the grid.

5.2.6.6 **PBR Docket**

Stakeholders saw value in the PBR docket process and outcomes. Some stakeholders mentioned that it is too early in the docket process to understand if a light PBR or a more extensive implementation of PBR would work better. However, implementing PIMs is seen as a relatively easy way to better align the utility with the community goals in the near term. Some stakeholders pointed out that there is interest in more radical change, however, as incremental changes have not resulted in the necessary adjustments to move the utility.

5.2.6.7 **Metrics/Incentives:**

It was expressed by multiple stakeholders that IOUs respond well to incentives, but there was concern that this would just result in higher rates for ratepayers. One stakeholder recommended that the best approach for determining regulatory changes is first to determine what the utility's role should be in the system and then determining which assets should be owned by the utility, which could differ in front of and behind the meter and may also vary from what the utility operates. Following this assessment, the requirements for utility performance could then be determined and could include operational performance metrics that are quantifiable and transparent. This could include a political and negotiated discussion of how savings are shared.

Stakeholders explained that when selecting and designing metrics, regulators must understand that specific groups of PIMs work well together financially, and that PIMs cannot be cherry-picked. There are unintended consequences with each potential PIM, and the regulators should identify those with the fewest unintended consequences.

Some metrics were discussed by stakeholders including:

- rate stabilization or reduction;
- progress toward RPS, carbon-free energy;
- responsiveness to customers and interaction with the community;
- improved interconnection process, reduced time to connect, and transparency in the process;
- resiliency: primarily grid resiliency but also social and community resiliency;
- equitability of pay: for example, a potential metric could be the ratio of the utility CEO's salary to the salary of the average employee or the median household income for the utility's service territory, with the goal being for a lower ratio;
- energy resource planning;
- efficient, holistic service providers, including non-wires alternatives, similar to New York's Reforming the Energy Vision;
- the diversity of generation sources;
- valuing the unique goals for each island; and
- innovation: could include the number of new projects, number of scaled pilot projects, hiring a chief innovation officer at a high level in the utility, developing and implementing an innovation strategy.

5.2.7 Lighter Regulation for Co-ops

There was general support for reduced regulation for co-ops and many stakeholders viewed the current regulation as costly for KIUC. The stakeholders said that it would be difficult to estimate the costs of regulation but that in a rate case year it could be around $3 million. Stakeholders explained that the high costs to revise rates had prevented KIUC from implementing rate changes that it would like to make to better serve customers, such as an EV rate.

Stakeholders explained that lighter regulation would work because KIUC

- moves faster than HECO on many issues and is held up by regulation;
- knows their system well and is willing to experiment in ways that the HECO Companies are not;
- has strong leadership; and
- is flexible and adaptable.

Stakeholders mentioned that there may be a pathway for the PUC to follow to reduce regulation for co-ops but that it would most likely require legislative action for any change. If regulation were reduced, stakeholders expressed concern about how any inconsistencies with congressional direction would be enforced. The example of KIUC interpreting the Community-Based Renewable Energy docket differently than the legislature or PUC was discussed, with stakeholders questioning which body would be the one ultimately responsible for understanding these policies.

It was explained that KIUC primarily participates in dockets to ensure that they are not negatively impacted by resulting decisions. As such, stakeholders felt that reduced regulation for co-ops would lessen the PUC's burden.

Stakeholders hypothesized that there would not be as much opposition to reduced regulation as there was when KIUC formed. However, one stakeholder noted that there was opposition from the PUC in relation to the decoupling docket.

Stakeholders discussed the potential for a more "light-handed approach" where the co-op would not need to seek approval for specific actions as long as certain thresholds were not exceeded. Potential limits discussed included:

- A rate increase exceeding X%;
- Project costs exceeding $X; and
- Customer disputes are exceeding X% of the customer base.

If the thresholds are exceeded, PUC involvement would be triggered. However, it was noted that the thresholds would need to be designed to exclude factors beyond the control of the utility (e.g., pass-through fuel costs). Under this model, the PUC could still have the opportunity to weigh in on governance issues. Under this model, stakeholders suggested that project approval and rate approval could be deregulated with thresholds established (i.e., a dollar threshold above which projects would require approval).

Stakeholders felt that KIUC's board is strong and knowledgeable. There was some mention of increasing concern regarding the potential for board capture and if the board just complies with the desires of the CEO.

The stakeholders point to the community oversight as a result of the co-op structure as a benefit of KIUC and a reason that lighter regulation would work. It was explained that very few signatures are required to trigger a community-wide vote of a board decision but that it has still happened only twice. For both of these votes, the community supported the board's decisions. This is seen as a good check and balance for the board.

Stakeholders explained that they are not concerned about issues related to dispute resolution in a deregulated environment because the community has handled dispute resolution more informally since it is a small population. Additionally, stakeholders stated that it is not hard to change the board as 500 votes could swing the decision. If issues did arise, it was discussed that the CA's attorney general could act as a watchdog or advocate. There were only minimal concerns about the potential for the voting structure to create perverse incentives.

Other stakeholders explained that there is a need for continued regulation of co-ops in Hawaii, particularly in regards to rates, PPAs, and customer complaints.

5.2.8 Other Topics

5.2.8.1 Ownership Models

Stakeholders discussed various topics related to ownership models. In regards to co-ops, it was noted that KIUC was successfully established because there was a willing seller. Though KIUC is considered successful, some said that it is not merely successful because it is a co-op but because of the knowledgeable leadership, the utility's focus on keeping the community satisfied, the appetite for risk, and the community's small size which allows for decisions to be made quickly.

Moving to a co-op is not seen as a solution for all of the problems that people identify with the HECO Companies. It was discussed that a co-op model might be more challenging to operate on the other islands due to the population size and the need for transmission across more considerable distances. One stakeholder said that although there is a lot of discussion of or interest in co-ops, which it is imperative that a community would need to demonstrate that they are capable of purchasing and operating a utility before any change to a co-op be considered seriously. There seemed to be a consensus that a co-op model would not be successful on Oahu but could work on the Big Island and perhaps on Maui. Some stakeholders thought that a vertically integrated IOU has different drivers than wires only models that benefit the community.

Input differed on the interest in co-op ownership of a utility on the Big Island. One stakeholder explained that the general interest in developing a co-op declined after the PUC's ruling on the NextEra acquisition. Conversely, a different stakeholder said that community members are "emotionally drawn" to a model where they can directly influence the decisions. Even for those interested in the model, there are questions about how it would impact rates and how it would be operated. Multiple stakeholders mentioned that KIUC is viewed as a successful model because they have a higher penetration of on-grid solar and have pursued more innovative and experimental solutions (e.g., pumped hydro, solar plus storage). It was noted that KIUC seems to be able to act more quickly and that it has a more straightforward procurement process.

Stakeholders explained that the IOU model only works well if the PUC can regulate effectively and they questioned the PUC's current ability to do this. The ownership model was not seen as the root of the problem. Instead the utilities' bias toward capital investments is.

There was some interest in the B-corp model as a way for the utility to access more patient capital that would give them the flexibility to make investments that have a longer return on investment. Stakeholders wondered how each regulatory model would work if utility ownership changed, particularly to a Sustainable B. Corp model.

5.2.8.2 Renewable Energy and Other Technologies

Stakeholders explained that Hawaii's solar industry was going strong under the net metering program but that it has been negatively impacted by the end of that program. As a result, smaller, local companies have been most severely affected. The solar industry is now focused on energy storage, mainly because it is required under the current regulatory context.

One stakeholder mentioned that there seems to be an overemphasis on the RPS when the focus should be more generally on larger goals like carbon reduction and affordability.

Stakeholders noted that the changes to the net metering program have resulted in substantially decreased opportunities for individuals to access DERs as a strategy to reduce their costs of electricity. However, DERs and microgrids are both considered good options for the Big Island.

5.2.8.3 The HECO Companies

The HECO Companies were seen by some as investing substantial time and resources in interacting with the community, particularly on the neighbor islands. Some mentioned that

communities on the neighbor islands question why IPPs are developing projects instead of the utility as they have no relationship with the IPPs and they are viewed as outsiders instead of neighbors that the community will interact with on a long-term basis. IPPs are considered by some to be unaware of the sensitivities in each community.

One stakeholder felt that a cultural shift is needed within the utility and that the HECO Companies need to understand better and be more responsive to customers, to operate as a platform that encourages innovation, be more agile, and support a robust DER market.

Some stakeholders recognized that it is valuable for the utility to be a partner in large-scale projects but that it is currently difficult to work with the HECO Companies.

5.2.8.4 Uniqueness of Hawaii

Stakeholders explained that Hawaii is unique from other systems. First, there are isolated grids on each island, and each is relatively small systems. The small size of the grid on neighbor islands has resulted in little interest from developers. There are unique cultures on each island with communities having different goals. Stakeholders explained that examples of regulatory models in other locations are not relevant to Hawaii because other areas have access to a larger grid which makes it easier to take risks.

Hawaii is a rural state and stakeholders explained that it is not useful for the focus of regulatory changes to be on creating markets that only work in larger states with more liquidity and market actors. Rural areas like Hawaii do not have the liquidity necessary for these market-based models to function well. In general, stakeholders pointed out that it can take a long time for anything to be developed in Hawaii and that it is vital for any results of this analysis to be actionable. One stakeholder explained that energy planning is a complicated process and that it can be especially difficult to develop any project on the Big Island which further complicates the planning process.

5.2.8.5 Non-wires Alternatives

While some stakeholders did not see non-wires alternatives as an option that would work well in Hawaii, others saw benefit in disaggregating generation and wires. They felt that this would address the problem of the utility operating as a monopoly and monopsony by creating competition.

5.2.8.6 Stakeholder Engagement

Stakeholders noted that the stakeholder process for this analysis could be influenced by "those who speak most loudly" and not represent the diverse interests and priorities of the communities on each island. Regardless of the model that the PUC decides to adopt, it is imperative that the changes are messaged well to the community, or any change will not be successful.

5.2.8.7 Regulatory Levers

One stakeholder explained that for regulation changes to be impactful, there will need to be multiple levers implemented. Currently, the PUC's primary lever is regulating what is allowable for a utility to rate base. It is possible for PBR to be implemented to include basic operations metrics (e.g., call center response times, interconnection times, etc.) that are easily measurable

and auditable and are not open to interpretation. These types of levers have only a minimum impact on increasing the value to the system, so they should be limited in use.

One stakeholder pointed out that if too much of the utilities' profits are tied to incentive mechanisms, the utility may focus their performance on these metrics and other areas of operation could suffer. The PUC will need to be careful in establishing metrics and implementing PBR to avoid unintended consequences. To address this, it would be useful to expand the incentive metrics beyond operational areas. However, these metrics would be much more difficult to measure, particularly any novel metrics.

A third lever is shared savings where the utility is given credit for their actions to reduce the rate base. Previous proposals related to this have included too large of a reward for the utility, but the reward should be just large enough to make it worthwhile for the utility to take action. This can be very valuable for the utility because there are low-cost options that they can implement to reduce the rate base. For example, the PUC has implemented a version of this with a new renewable request for proposals ("RFPs") where the utility can keep some of the savings they achieve if they sign a contract for an RFP that is below the price that the PUC has established for renewable RFPs.

A potential concern with this, however, is that it can be challenging to track and measure where savings begin and if there are unnecessary delays in project deployment which would impact when the savings should have occurred. Penalties can be an effective way to mitigate this risk. The fourth lever to consider is the RPI-X model of PBR. The stakeholder viewed this as a critical component for success in revising the regulatory model to be more effective. For example, it was stated that there "is a ton of bloat" in the HECO Companies that could be reduced through efficiency improvements, specifically middle management. If all of this is implemented well, the rate base will continue to grow, but primarily on the grid-side as there is a shift toward non-utility distributed generation. The grid would then shift from being a "giant battery" to a "giant interconnection." If this happens, the rate base will increase through sales will decrease, so opportunities to increase sales, like from the electrification of transportation, will be very important.

5.2.8.8 **Other Topics and Concerns**

- Customers should own their data as data sharing will be essential to open access to the grid.
- It was noted by multiple stakeholders that there are broader community goals than just clean energy, including a sustainable economy, but that regulatory requirements on the utility cannot influence all of these goals.
- Some stakeholders felt that it is not realistic for unique regulatory models to be put in place on different islands.
- One stakeholder explained that electricity is a public good and that the utilities providing electricity should be accountable to the people they serve.
- Regardless of the model, it is vital for rate design to be considered. The utilities have been maximizing fixed costs as a reaction to solar. While economists would recommend

implementing time of use pricing to address this, because it may not be that reducing peak demand is the priority now. Instead, rate design should consider that a goal is increased flexibility over time as the grid moves toward being a giant interconnection.

- One stakeholder would like to see the HECO Companies operate more as a platform and technology provider.
- Many stakeholders brought up electrification of the transportation sector as an important topic that should be considered in any regulatory model revision.
- Some stakeholders were interested in understanding how a hybrid of regulatory models may work best for Hawaii.
- It was noted that consumer priorities are not monolithic and can vary substantially, with different groups prioritizing different functions for the utility (e.g., LMI focus, increased choice for consumers, reliability, affordability, resiliency, etc.).

6 Conclusion

While the discussions at each workshop were unique as stakeholders expressed their priorities and concerns, there were some themes that came up multiple times during the two weeks, namely:

- reliable electricity is a priority, and the current regulatory model has been successful at ensuring utilities provide reliable service;
- minimizing rates now and in the future is a priority;
- that stakeholders greatly value the ability to be engaged in and influence utility decisions to ensure they are aligned with community needs;
- there is much interest in improving resiliency in the electrical grid across the state, particularly in relation to severe storms;
- there is demand for more renewable energy, from more diverse sources, and for more opportunity for a customer-sited generation;
- the regulatory model must allow for and encourage innovation so that the utility can meet its goals in the most cost-effective manner;
- there is concern that the current regulatory model does not allow for the competition in generation necessary for generation to be developed in the most cost-effective way;
- that any model must consider the equity of costs and access to renewable resources as there is concern that grid defection is impacting the LMI community the most.

6.1 Status Quo

All stakeholders agreed that the current regulatory model results in the provision of reliable electricity to the majority of the state, though there was concern about grid resiliency. Across the state, stakeholders believed that this model has not been successful in minimizing electric rates.

Many stakeholders expressed dismay over the lack of community involvement in the utility decision-making process required under the status quo and showed that the utility is not incentivized to take action or make investments in line with community priorities. Some suggested that increasing representation from each island on the PUC would be a good first step to ensuring that priorities from each island are addressed. Some stakeholders explained that this model does not allow sufficient access to the grid for IPPs and does not sufficiently incentivize investments in renewables. Overwhelmingly, stakeholders discussed that the PUC does not have adequate resources to handle its current tasks.

6.2 HERA

In general, stakeholders did not think that HERA would be a good solution for Hawaii. While many noted that it might increase grid access and increase deployment of renewables, a majority of stakeholders thought that HERA would be redundant and increase overall costs.

6.3 ISO

Though it was recognized that an ISO would increase competition, stakeholders agreed that it would be too costly and that the market is too small in Hawaii for an ISO to work.

6.4 DSPP

Stakeholder opinions varied considerably regarding a DSPP model. While many explained that this model would not work in Hawaii, others saw it as a way to increase competition and deployment of DERs. Many stakeholders mentioned that the costs would be too high, particularly the necessary up-front investments required to implement this model.

6.5 PBR

Stakeholders were supportive of using incentives under PBR to encourage utilities to make investments and take actions that are in line with community and policy goals. The potential metrics discussed varied greatly and included cost stabilization, cost equity, increased renewables, incorporation of community priorities, reliability, and resiliency. Multiple stakeholders suggested that it would be critical for representatives from each island to be involved in designing the metrics. There was general agreement that linking utility revenues to performance would be beneficial.

Many stakeholders highlighted that it would be difficult to design and implement PBR well and there was substantial concern about unintended consequences that would result if it is not designed well. As a result, some stakeholders explained that it might be too risky. Preferences varied from a PBR model that would create minor adjustments to the status quo to one that would result in a major overhaul of the system.

6.6 Lighter Regulation of Co-ops

There was support for lighter regulation of co-ops, mostly from stakeholders on Kauai. Many stakeholders said that KIUC has demonstrated the ability to manage and operate the utility well and that PUC regulations are unnecessary. Some stakeholders suggested that Hawaii follow the example on the mainland where co-ops are not regulated as heavily as IOUs. Stakeholders on Kauai noted that a reduction in regulations would reduce costs for both KIUC and the PUC.

6.7 Future Stakeholder Engagement Opportunities

The results from these workshops and the other stakeholder engagement conducted throughout this project will be incorporated into the analyses and the final report, to be submitted to DBEDT in October 2018. Feedback will be collected over the course of the project. All feedback related to the regulatory model analysis that is received by August 31st, 2018 will be summarized and added as an addendum to this report. All other feedback will be incorporated into future reports submitted under this project.

The Project Team will continue to engage with stakeholders to keep them apprised of the status of the project and to receive their input related to the project. The Project Team will be conducting stakeholder workshops in the fall of 2018 to provide an overview of the results of the analysis.

7 Appendix A: Overview of Regulatory Models

The workshops participants were provided with a worksheet providing a high-level overview of different regulatory models. The worksheet is listed on the following two pages.

Hawaii Utility Regulatory Models Community Workshops
June 12-22, 2018

This worksheet is provided as a reference on different utility regulatory models. If you choose to, please use this sheet to record your thoughts on potential regulatory models and hand it to your facilitator to be recorded as feedback.

Name and Organization (optional):

Overview of Regulatory Models

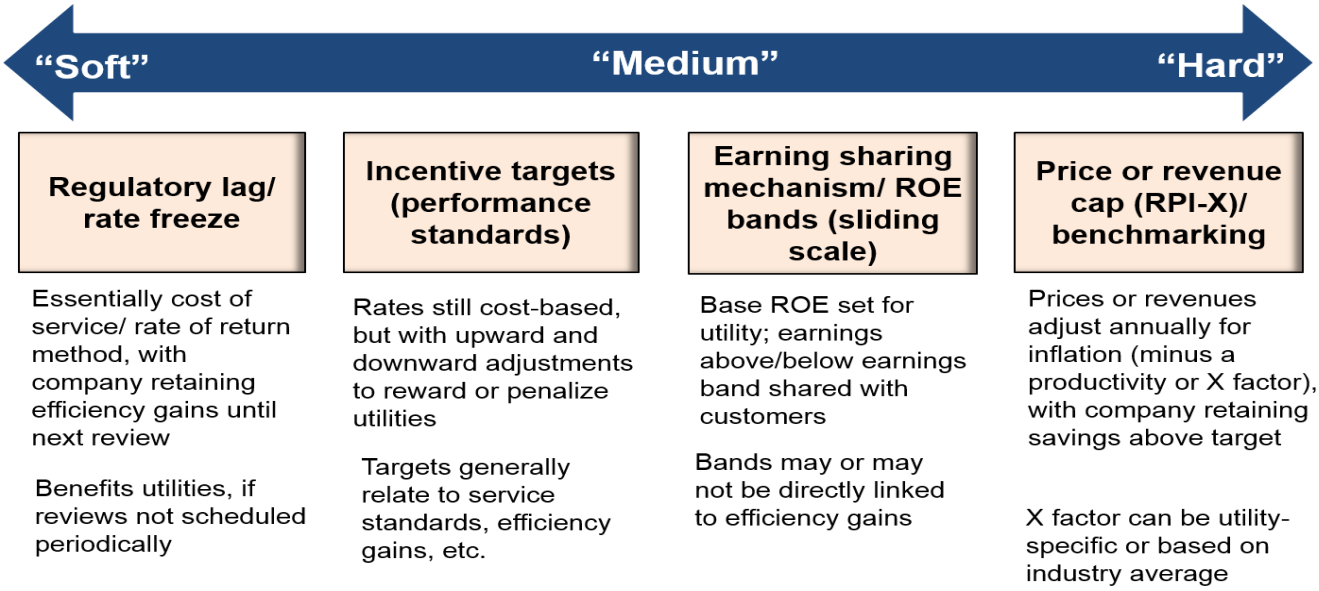
Model	Description
Status Quo (Cost of Service; PUC regulation of vertically-integrated utilities)	Incumbent utilities own and operate all generation, transmission, and distribution assets and are regulated by the PUC. Currently, HECO utilities are permitted to collect rates that are based on their costs of providing electric service, plus an allowed return.
Hawaii Electricity Reliability Administrator (HERA)	HERA would be a new entity that would be charged with ensuring reliability and grid access. This new organization would be formed through existing state law and would support the PUC.
Independent System Operator (ISO)	A new entity would be formed to perform the day-to-day operation of the electric grid and manage resource planning and other important grid functions. This would not entail any changes in the ownership of any utility generation, transmission, and distribution assets.
Distribution-Focused Regulation	A Distributed System Platform Provider (which could also be a utility) would own the distribution system and would facilitate access to competitive third-party distributed energy resource providers.
Performance-Based Regulation (PBR)	PBR would replace or augment cost-of-service regulation and reform the way that utilities collect revenue by tying revenues more closely to the utility's performance in (i) achieving state policy goals, (ii) ensuring greater cost control, (iii) making efficient investments, and (iv) safeguarding fair distribution of risks between utilities and customers.
Decreased Regulation of KIUC	The PUC would no longer regulate various elements of KIUC's operations, including rate-setting. The PUC would continue to regulate HECO utilities.

Model	What strengths do you think this model has?	What weaknesses do you think this model has?
Status Quo		
HERA		
Independent System Operator		
Distribution-Focused Regulation		
Performance-Based Regulation		
Decreased Regulation of KIUC		

What other comments do you have on different regulatory models?

Performance-Based Regulation Detail

PBR exists as a continuum with "soft" to "hard" mechanisms and not just a single type of regulatory regime.



PBR Component	What strengths do you think this approach has?	What weaknesses do you think this approach has?
Provide rewards for the utility if they achieve set targets		
Penalize the utility for not meeting certain performance targets		
Share earnings between utility & customers		
Remove utility incentives between capital and operating expenses		
Cap utility prices or revenues, and allow the utility to benefit from cost savings		

What types of outcomes or metrics do you think PBR should encourage? Examples: Reliability and availability, Customer satisfaction, Safety, Environmental impact (e.g., RPS goal), Social obligations, Innovation

What other comments do you have on PBR

8 Appendix B: Outreach Flyers

All outreach flyers can be accessed at the links below.

City and County of Honolulu

- Kailua: https://www.dropbox.com/s/s2fsob0pjum702i/Kailua.docx?dl=0
- Honolulu: https://www.dropbox.com/s/jpdd5l0vo2oii65/Honolulu.docx?dl=0

Hawaii County

- Hilo: https://www.dropbox.com/s/sbithk48afbmu1j/Hilo.docx?dl=0
- Kona: https://www.dropbox.com/s/5luewztsbk4oxdr/Kona.pdf?dl=0

Kauai County

- Lihue: https://www.dropbox.com/s/om0wm3b7xgnn2oj/Lihue.docx?dl=0

Maui County

- Kaunakakai, Molokai: https://www.dropbox.com/s/8gcgiydm2otx68h/Kaunakakai.docx?dl=0
- Lanai City, Lanai: https://www.dropbox.com/s/brlly5m29pdvn8t/Lanai.docx?dl=0
- Wailuku, Maui: https://www.dropbox.com/s/kw6wo98dve7u4ol/Wailuku.docx?dl=0

9 Appendix C: Press Release

HAWAII STATE ENERGY OFFICE SCHEDULES COMMUNITY MEETINGS ON UTILITY MODEL STUDY

Posted on Jun 12, 2018 in News Releases

For Immediate Release: June 12, 2018

HONOLULU – The Hawaii State Energy Office (HSEO) will host a series of community meetings across the state starting tomorrow to gather community input for the second phase of a study being done on future models for utility ownership and regulation in Hawaii.

The latest round of community meetings will focus on the future of electric utility regulatory models, including performance-based regulation and the role the Public Utilities Commission plays in achieving state energy goals. The first series of community meetings held last October addressed the issue of utility ownership.

HSEO, a division of the State Department of Business, Economic Development and Tourism (DBEDT), is undertaking the study at the request of the Hawaii State Legislature to evaluate the costs and benefits of various electric utility ownership models, as well as the viability of various utility regulatory approaches to help Hawaii in achieving its energy goals. The study will examine scenarios for each of Hawaii's counties.

HSEO has contracted with Boston-based London Economics International (LEI) to carry out the study, which is expected to be completed by January 2019. LEI and subcontractor Meister Consultants Group will lead the community meetings for June 13-22. The meeting schedule is as follows:

Honolulu County:

- Kailua, June 13, 5:30 – 7 p.m., Enchanted Lake Elementary School Cafeteria, 770 Keolu Dr. Kailua Event Flier and Registration
- Honolulu, June 14, 6:00 – 7:30 p.m. Foreign Trade Zone #9, Homer Maxey Conference Center, 521 Ala Moana, Suite 201. Honolulu Event Flier and Registration

Kauai County:

- Lihue, June 15, 5:30 – 7 p.m. Kauai High School Cafeteria, 3577 Lala Rd. Kauai Event Flier and Registration

Maui County:

- Wailuku, June 18, 6:00-7:30 p.m. Waikapu Community Center, 22 E Waiko Rd. Maui Event Flier and Registration

- Kaunakakai, June 19, 6:00-7:30 p.m. Mitchell Pauole Center Main Hall, 90 Ainoa St. Molokai Event Flier and Registration
- Lanai City, June 20, 6:00-7;30 p.m. Lanai Community Center, Eighth St. and Lanai Ave. Lanai Event Flier and Registration

Hawaii County:

- Hilo, June 21, 5:30 – 7 p.m. Waiakea High School, 155 W Kawili St. Hilo Event Flier and Registration
- Kailua-Kona, June 22, 5:30 – 7 p.m. NELHA Research Campus, Hale Iako Building, 73-970 Makako Bay Drive. Kailua-Kona Event Flier and Registration

Community members planning on attending the meetings are encouraged to RSVP at the link above. Light refreshments will be served. Those unable to attend a meeting in person can view a copy of the material presented, which will be posted on HSEO's website energy.hawaii.gov/utility-model after the meetings, and may participate by submitting feedback via email to: dbedt.utilitybizmodstudy@hawaii.gov. Questions about the meetings or the study can be emailed to the same address.

10 Appendix D: Email Invitation Text

Stakeholders across the state that had been engaged with this project in the past, expressed interest in participating, or were identified through discussions with DBEDT and the Core Group were sent the following email invitation from DBEDT.

INVITATION TEXT:

Under the direction of the Hawaii State Legislature, the Hawaii State Energy Office (HSEO) within the Department of Business, Economic Development, and Tourism is undertaking a study on the future of electric utility regulatory models in Hawaii.

HSEO has contracted with Boston-based London Economics International to carry out the study, which is expected to be completed by January 2019.

As a part of this study, you are invited to share your thoughts and input on the future of electric utility regulatory models including performance-based regulation and the role the Public Utilities Commission plays in achieving state energy goals, including achieving 100% renewable energy and minimizing rate increases. We welcome everyone's participation and request that you register via the link below. Light refreshments will be served.

The meetings will occur statewide, June 13 through June 22, 2018.

Register today! (linked to: http://hawaiistateenergyoffice.cmail20.com/t/t-l-uithpy-xpskrll-d/)

If you have any questions or are not able to attend a meeting and would like to provide feedback via email, please contact us at dbedt.utilitybizmodstudy@hawaii.gov. The meeting materials will be posted on the Community Meetings page.

We look forward to your participation and input.

11 Appendix E: Scope of work to which this deliverable responds

Task 2.2.5 Outreach Plan and documentation of results of public outreach on each island served by an electric utility. CONTRACTOR shall develop and carry out an outreach plan approved by the STATE to solicit public input from each island currently served by an electric utility on the results of TASKS 2.1.1 through 2.2.4.

DELIVERABLE FOR TASK 2.2.5. CONTRACTOR shall provide all work to support an outreach plan for public input, designing and conducting outreach processes and activities with stakeholders, and incorporate feedback throughout the duration of the project as described in Proposal Scope TASK 2.2.5. CONTRACTOR shall provide a written Outreach Plan to the STATE for approval prior to carrying out the plan. CONTRACTOR shall provide documentation of results of public outreach on each island in MS Word and spreadsheets in MS Excel. CONTRACTOR shall submit deliverable for TASK 2.2.5 to the STATE for approval.

Ranking and recommendation of regulatory models for further review

Prepared by London Economics International LLC and Meister Consultants Group for the Hawaii Department of Business, Economic Development, and Tourism

September 6, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group ("the Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism to conduct a study to assess the costs and benefits of different electric utility ownership models and regulatory models that could support the State of Hawaii in achieving its energy goals ("DBEDT Study"). As part of the engagement, this working paper provides a ranking process and rationale for the recommendation of three regulatory models for further consideration. The three regulatory models recommended for further analyses for counties served by the HECO Companies include: (1) Hybrid model, (2) Conventional performance-based regulation ("PBR") with Light Hawaii Electricity Reliability Administrator ("HERA") model, and (3) Outcomes-based PBR model. For Kauai, the Project Team selected (1) the HERA model, (2) Independent Grid Operator, and (3) Lighter PUC regulation for further review.

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cherrylin@londoneconomics.com

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List of acronyms

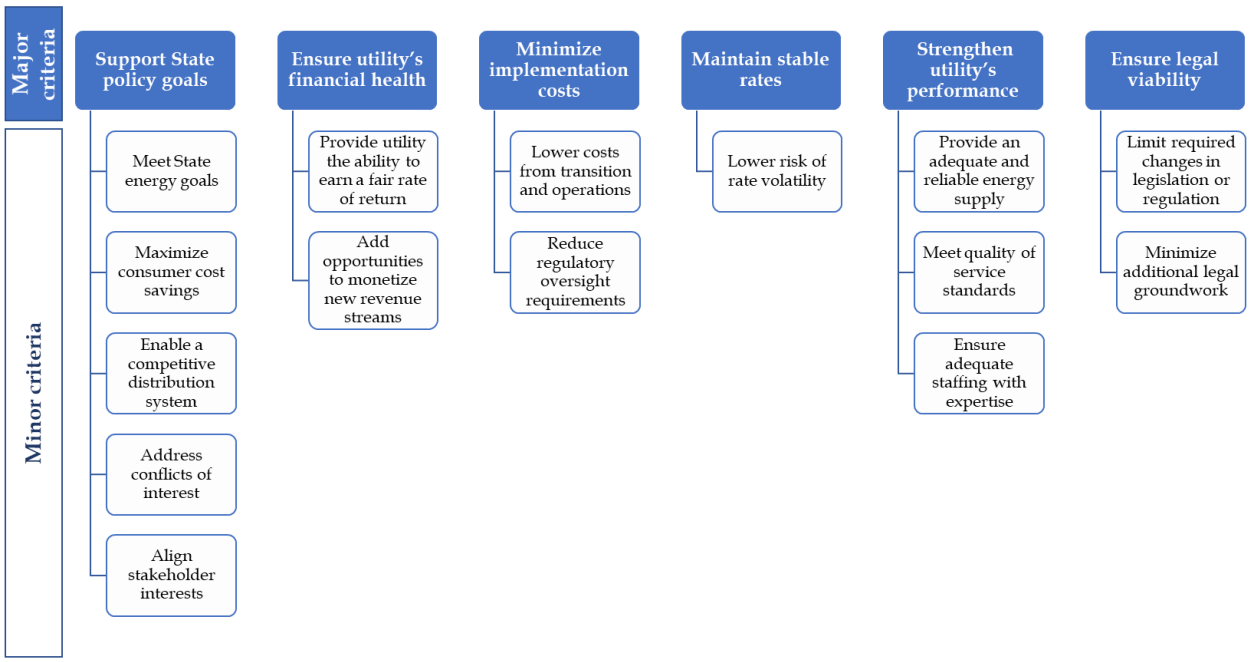
DBEDT	Hawaii Department of Business Economic Development and Tourism
DER	Distributed Energy Resource
DG	Distributed Generation
DR	Demand Response
DSPP	Distributed System Platform Provider
EE	Energy Efficiency
ESM	Earnings Sharing Mechanism
EV	Electric Vehicle
HECO	Hawaiian Electric Company, Inc.
HELCO	Hawaii Electric Light Company, Inc.
HERA	Hawaii Electricity Reliability Administrator
HSEO	Hawaii State Energy Office
IGO	Integrated Grid Operator
IOU	Investor-owned Utility
IPPs	Independent Power Producers
ISO	Independent System Operator
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MCG	Meister Consultants Group
MECO	Maui Electric Company, Ltd.
PBR	Performance-based Regulation
PIMs	Performance Incentive Mechanisms
PUC	Public Utilities Commission
RAB	Regulated Asset Base
RPS	Renewable Portfolio Standards
T&D	Transmission and Distribution
TOTEX	Total expenditure

1 Executive summary

The Hawaii Department of Business Economic Development and Tourism ("DBEDT") contracted London Economics International LLC ("LEI"), together with Meister Consultants Group (the "Project Team"), for a study that will assess the costs and benefits of various electric utility ownership models and regulatory models that can support the State in achieving its energy goals. This working paper, which corresponds to Task 2.2.6 in the project scope of work, provides a ranking of the regulatory models introduced in Task 2.1.1. The ranking of the regulatory models was undertaken so that the three most feasible and viable regulatory models may be considered for more in-depth analysis in subsequent tasks.

The Project Team developed a set of major criteria with minor sub-criteria (based on the State-specified criteria and Scope of Work), which guided the assessment. Figure 1 below shows the set of major and minor criteria used to assess the regulatory models.

Figure 1. Major and minor criteria



The Project Team scored the potential performance of the regulatory models on each evaluation criterion as positive, neutral, or poor, subject to certain assumptions. Moreover, within these major criteria, the ranking methodology weighed some minor criteria more heavily than others based on the relevance of the criterion to the goals of the DBEDT Study, implications toward the achievement of other standards, and value to stakeholders. The weights of all minor criteria total 100%. Figure 4 summarizes the weights of these criteria.

Based on the analysis, guided by the ranking, the Project Team concludes that the three most promising regulatory models for Honolulu, Hawaii, and Maui Counties for further review are:

1) **Hybrid model** [combination of Outcomes-based Performance-Based Regulation ("PBR"), Distributed System Platform Provider ("DSPP"), and Integrated Grid Operator ("IGO")],
2) **Conventional PBR** with a streamlined version of the Hawaii Electricity Reliability Administrator ("**Light HERA**") model, and
3) **Outcomes-based PBR** model.

As discussed in previous working papers, **Outcomes-based PBR,** which is the most comprehensive PBR regime, seeks to incentivize the utility toward beneficial outcomes for society. These potential outcomes include i) enhancing customer experience, (ii) improving utility performance, (iii) achieving public policies and goals, and (iv) maintaining healthy financial performance. Under this PBR regime, utilities have flexibility on preferred solutions and strategies to attain those outcomes. Other mechanisms such expanded Performance Incentive Mechanisms ("PIMs"), Earnings Sharing Mechanism ("ESM"), total expenditure ("totex") approach,[1] and more stringent reporting regimes are included under the Outcomes-based PBR.[2]

Conventional PBR with Light HERA would combine a PBR regulatory regime with a Light HERA entity to oversee the interconnection process and reliability planning. Under Conventional PBR, the revenue requirements of the utilities are based on an indexing formula (inflation less productivity factor) for the second and third years of operation. Mechanisms such as an expanded set of PIMs, ESM, and totex approach are included under this PBR regime. The Light HERA entity would perform the task of an ombudsman, for example, stepping in for dispute resolution when required.

The Hybrid model assumes an independent entity (i.e., Independent Grid Operator or "IGO") would manage the dispatch and planning functions of both the transmission and distribution assets. Moreover, under this model, the utilities would serve as the Distributed System Platform Provider ("DSPP"), providing open access to Distributed Energy Resources ("DERs") and other providers offering energy management or customer data analytics services. Customers, service providers, DERs, and utilities conduct transactions of energy and services on the modernized grid platform provided by utilities. For the utilities to remain effective in their traditional functions even as a DSPP, an Outcomes-based PBR would also be implemented. The utilities,

[1] Under a totex approach, there is no distinction between the capex and operating expenditures as the utilities are incentivized to consider the whole life costs, rather than choose between a capital expenditure or an operating expenditure solution.

[2] Task 2.1.1 (Introduction to the Regulatory Models) provides more description on the mechanisms under an Outcomes-based PBR.

Public Utilities Commission ("PUC"), and stakeholders would determine appropriate outcomes that the utilities need to achieve by the end of the regulatory period.

The Project Team's separate analysis conducted for Kauai County concludes that the three most promising regulatory models for Kauai County are:

1) **HERA model**,
2) **IGO**, and
3) **Lighter PUC Regulation**.

Under the **HERA model**, the PUC's role in ensuring grid access and reliability would be transferred to HERA. The HERA, as an entity, was authorized by the Hawaii State legislation (Act 166) in 2012.

The Project Team envisions the **IGO** as an entity that combines the work of an Independent System Operator and a Distribution System Operator. It would assume responsibility for resource planning, oversee system operations (including dispatch), and determine the investment requirements for both transmission and distribution networks. While the utility would continue to operate as a co-op, its planning and dispatch functions would be assumed by the IGO.

A **Lighter PUC Regulation** model would primarily serve to reduce Kauai Island Utility Cooperative's ("KIUC") regulatory burden. All utility functions and operations would remain the same, but KIUC would no longer be required to obtain PUC approval for rate changes, supply contracts, and capital expenditures unless rates increase, or capital expenditures surpass, a certain threshold. The PUC would still remain involved in dispute resolution.

These three regulatory models will be subject to additional analyses in Tasks 2.3 to 2.5.

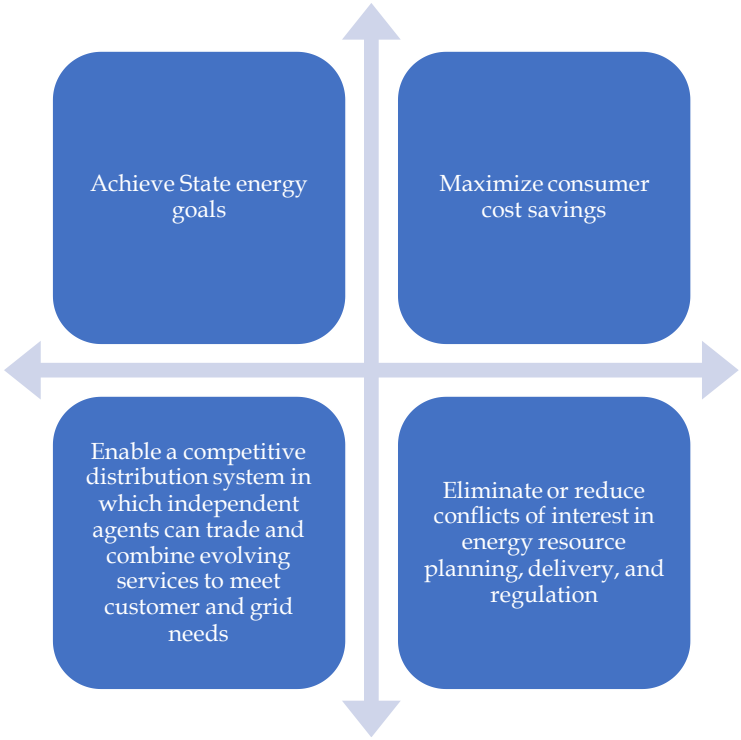
2 Introduction and scope

2.1 Project description

DBEDT was directed by the State's legislature to commission a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models which can best facilitate the achievement of the State's energy goals. The Project Team, through a competitive sealed proposals procurement,[3] was contracted to perform this study.[4]

The project aims to evaluate different utility ownership and regulatory models—based on the State's key criteria—and determine which among them can best be adapted in Hawaii[5] (Figure 2).

Figure 2. State's key criteria in evaluating the models



Source: Scope of Services under Contract No. 65595

[3] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[4] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[5] House Bill No. 1700 Relating to the State Budget.

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models that serve each county of the state.

Furthermore, it will also aid in identifying the process that must be followed in forming such ownership and regulatory models as well as determining whether such models would create synergies in the sector. Such synergies can be appreciated in terms of increasing local control over energy sources serving each county, diversifying energy resources, promoting economic development, reducing greenhouse gas emissions, improving system reliability and power quality, and lowering costs to all consumers. [6]

2.2 Role of this deliverable relative to others in the project

This deliverable corresponds to Task 2.2.6 in the project scope of work. It builds on several previous deliverables, namely, introduction of the regulatory models (Task 2.1.1), high-level assessment based on the state goals (Task 2.2.1), current markets using such regulatory models (Task 2.2.2), potential stranded costs (Task 2.2.4), and high-level feasibility of ownership models (Task 2.2.3).

Moreover, the rankings in this deliverable take into consideration feedback received as part of the stakeholder engagement efforts (Task 2.2.5 - Community Discussions on Regulatory Models), as well as numerous one-on-one meetings with stakeholders. These stakeholder engagement efforts elicited valuable feedback and underscored the importance of the key criteria that guided the ranking design and weighting.

Finally, this task will serve as the precursor to further analysis in subsequent tasks:

- identification of steps, costs, and projected timelines required by the change from the current regulatory model to the recommended regulatory models (Task 2.3.1);
- analysis of Hawaii law and history to determine the regulatory and legislative changes needed in the implementation of the recommended regulatory models (Task 2.3.2);
- identification and assessment of the impact of known or potential financial and operational risks for different stakeholders under each regulatory model (Task 2.3.3);
- evaluation of how each regulatory model could impact state agencies such as the Public Utilities Commission and stakeholders such as the Consumer Advocate (Task 2.3.4);
- estimated potential of each model in increasing distributed energy resources, demand response, system security, reliability, and resilience and meeting Hawaii's RPS milestones through 2045 (Task 2.4.1);

[6] Hawaii Contract No. 65595. Scope of Services.

- estimated annual revenue requirement (including major costs by category) of each of the recommended regulatory models; comparison of the outcomes of the three regulatory (Task 2.5.1);
- assessment of system average retail rates for an average residential, commercial, and industrial customer (up to 2045) in each regulatory model (Task 2.5.2);
- analysis of how costs differ (as well as an explanation of the revenue requirement calculation) under each regulatory model (Task 2.5.3);
- review of issues that could impact the valuation of an electric utility and identify key risks in utility valuations for each regulatory model (Task 2.5.4); and
- identification of funding mechanisms for each regulatory model (Task 2.5.5).

3 Criteria and methodology

The Project Team determined the ranking by first establishing major categories through which the regulatory models were evaluated. Following this, the Project Team developed "minor categories" or sub-criteria, which further refined the scope of major categories. The Project Team then designed a weighting system to indicate the relative importance of each of the minor criterion. Using existing data, literature, case studies, interviews, and insights gathered from stakeholder workshops, the Project Team determined the final weighting and scoring of the regulatory models. Many of these insights were presented in the previous working papers.[7] This methodology will be discussed in this section.

3.1 Models reviewed

The Project Team initially evaluated nine regulatory models that could be implemented in the counties served by HECO Companies. These counties include Hawaii, Oahu, and Maui. The Project Team reviewed more regulatory models than what was asked for in the Scope of Work to ensure more comprehensive analytical work. More specifically, the Scope of Work required the team to look into five regulatory models:

(1) Status Quo;

(2) Status Quo with increased oversight from Hawaii Electricity Reliability Administrator ("HERA") or the "HERA model;"[8]

(3) Independent System Operator ("ISO");[9]

(4) distribution-focused regulatory model (or the Distributed System Platform Provider or "DSPP model"); and

(5) Performance-Based Regulatory model ("PBR").

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[7] These include Task 2.2.1 (which evaluated the regulatory models with respect to State goals), Task 2.2.3 (which provided an initial high-level feasibility overview of each of the regulatory models), and Task 2.2.5 (which produced the results of the stakeholder outreach workshops from June 2018).

[8] A Light HERA was also considered as an alternative option to HERA. Under the Light HERA, HERA (the entity) could act as an ombudsman, an appeals body focused on hosting capacity and interconnection. It would have the technical capability to set target timeframes and standard models for calculating interconnection costs in order to arbitrage disputes between customers and the utility. See Task. 2.1.1. for a detailed description of the Light HERA.

[9] As discussed in Task 2.2.1, the functions of the ISO and the independent distribution system operator are combined into an Independent Grid Operator ("IGO"). Given the smaller size of Hawaii State's transmission and distribution systems (compared to other jurisdictions), combining these two regulatory models would be more effective and efficient.

However, the Project Team decided to assess three PBR variants—Light, Conventional, and Outcomes-based—because PBR is an umbrella term that covers a wide range of mechanisms and combinations of these mechanisms:[10]

- **Light PBR** would feature expanded Performance Incentive Mechanisms ("PIMs") with rewards and financial consequences, as well as the current Earning Sharing Mechanism ("ESM").

- **Conventional PBR** would use an indexation formula and a revenue cap to determine the revenue requirements of the utilities, together with PIMs, a symmetrical ESM, and a total expenditure ("totex") approach in treating expenditures.[11]

- **Outcomes-based PBR** would focus on the outcomes related to enhancing customer experience, improving utility performance, achieving public policies and goals, and attaining healthy financial performance. It also features an expanded set of PIMs, an ESM, and longer regulatory period (5 years),[12] among the other features of this PBR.

Furthermore, the analysis in Task 2.2.1 (Evaluation of Regulatory Models Relative to State Criteria) showed that combining some of the regulatory models would be more effective in facilitating the achievement of state goals. In particular, two combinations stand out given the state's goals:

(1) Hybrid Model - a combination of the Outcomes-based PBR, IGO, and DSPP; and

(2) Conventional PBR with Light HERA.

The Project Team also assessed five models for Kauai County, namely:

(1) Status Quo;

(2) HERA model;

(3) IGO;

(4) DSPP; and

(5) Lighter PUC regulation.

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[10] Task 2.1.1 (Introduction to the Regulatory Models) provides a detailed discussion of the difference between these three PBR models.

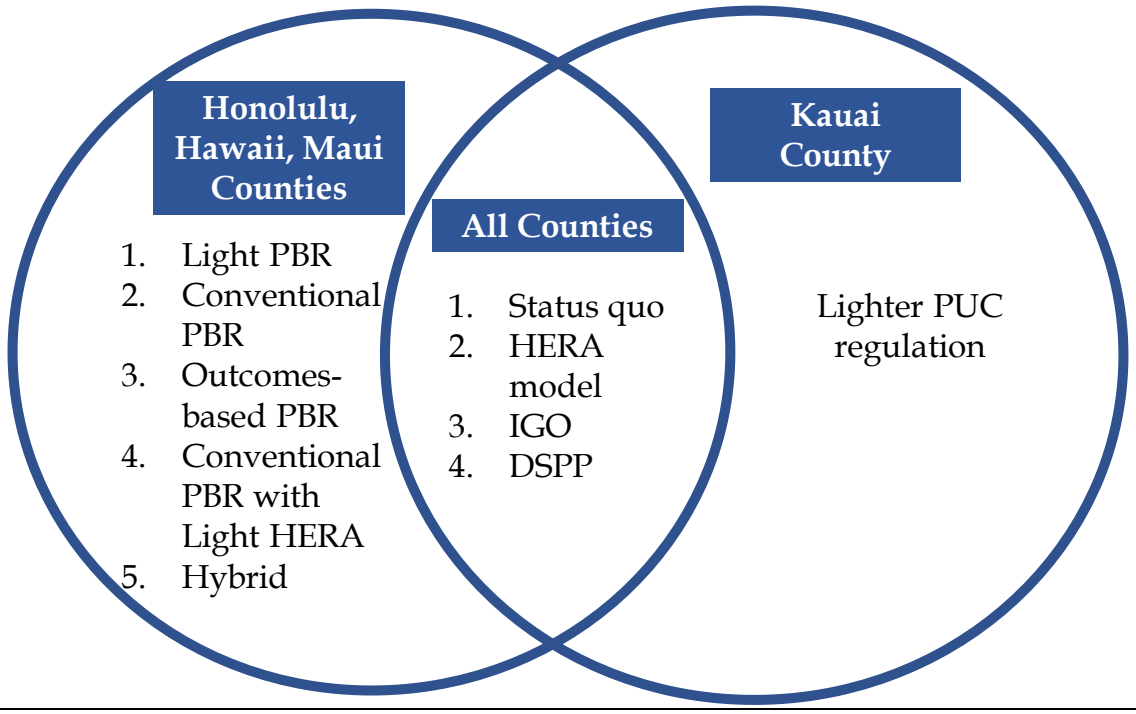
[11] See Footnote 1.

[12] In addition to these, the Outcomes-based PBR also incorporates the totex approach and a more stringent reporting requirement. It also requires utilities to submit capital expenditure and asset plans in its PBR submission.

PBR was not included in the evaluation for Kauai County because cooperatives are excluded from the PBR legislation. The Lighter PUC Regulation was added as an option since KIUC *"considers and potentially seeks increased exemption from regulation by the PUC."*[13]

This analysis identified three regulatory models that are considered for further analysis in subsequent tasks. Figure 3 shows the regulatory models reviewed for the different counties.

Figure 3. Regulatory models reviewed



3.2 Criteria and major evaluation categories

The Project Team developed and categorized several evaluation criteria, taking into consideration the Scope of Work's specified criteria. Stakeholder feedback generated during the community outreach and one-on-one meetings was also taken into consideration. Figure 3 shows the list of the major and minor criteria, which are discussed below.

[13] KIUC. *Strategic Plan Update 2016 – 2030.* January 31, 2017 adopted. Page 5.

Figure 2. Major and minor criteria

Support State policy goals	Ensure utility's financial health	Minimize implementation costs	Provide stable rates	Strengthen utility's performance	Ensure legal viability
• Meet State energy goals • Maximize consumer cost savings • Enable a competitive distribution system • Address conflicts of interest • Align stakeholder interests	• Provide utility the ability to earn a fair rate of return • Provide financial incentives	• Lower costs from transition and operations • Reduce regulatory oversight requirements	• Lower risk of rate volatility	• Provide an adequate and reliable energy supply • Meet quality of service standards • Ensure adequate staffing with expertise	• Limited required changes in legislation • Minimize additional legal groundwork

3.2.1 Criterion 1: Support State policy goals

Each regulatory model was scored based on its ability to help achieve the policy goals established by the legislation in House Bill 1700, which provided the directive for this Study. These study criteria, introduced in Task 1.2.1., include the following and are further discussed below:

1. achieve State energy goals;
2. maximize consumer cost savings;
3. enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer needs; and
4. eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation.[14]

3.2.1.1 Achieve State energy goals

This sub-criterion focuses on the regulatory model's ability to enable the achievement of Hawaii's Renewable Portfolio Standard ("RPS") target, which is to procure 100% of net electricity sales from renewable energy by 2045. Hawaii's utilities have made significant strides toward the achievement of the 100% renewables target under the existing regulatory structure. The Project Team evaluated the proposed alternative regulatory models based on additional or alternative levers available in each model. Such levers are meant to encourage compliance through incentives

[14] Hawaii State Energy Office. *Utility Model Study*, http://energy.hawaii.gov/utility-model (accessed August 21, 2018).

and/or penalties and address barriers to the growth of utility-scale and customer-sited renewable energy, battery storage, energy efficiency ("EE"), and demand response ("DR")—all of which help in assessing whether they would have a larger or smaller potential in facilitating the achievement of the State's energy goals.

3.2.1.2 Maximize consumer cost savings

State energy goals include the State of Hawaii's 100% renewable energy target as well as the five Energy Policy Directives of the Hawaii State Energy Office ("HSEO") which consist of:

1. diversifying Hawaii's energy portfolio;
2. connecting and modernizing Hawaii's grids;
3. balancing technical, economic, environmental, and cultural considerations;
4. leveraging Hawaii's position as an innovation test bed; and
5. promoting an efficient marketplace, that benefits producers and consumers.

Source: Hawaii State Energy Office, Hawaii Department of Business, Economic Development, and Tourism, "Energy Policy Directives," March 2017, available at: https://energy.hawaii.gov/wp-content/uploads/2011/08/EnergyPolicy_1pgr_rev-Mar2017.pdf

The Project Team evaluated the regulatory models based on how each model addresses the costs of producing and delivering electricity and the incentives for the improvement of operational efficiency.

Depending on the regulatory model, additional costs incurred by utilities or the oversight bodies (such as fees that help cover the costs of establishing and operating the regulatory agencies, incentive payments, or cost of regulatory proceedings) might be passed on to ratepayers. Therefore, the choice of a regulatory model for Hawaii must consider the additional costs that each model would entail alongside the potential savings that it can generate.

3.2.1.3 Enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs

For this sub-criterion, the regulatory models were scored based on whether they facilitate open grid-access at the distribution level for customers, DER providers, and other service providers. One of the goals articulated in House Bill 1700 is to *"enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer needs."* This goal is anchored on a desire to modernize Hawaii's electric grid by taking advantage of technological advancements in both software capabilities and renewable resources. Increased penetration of DERs opens new opportunities for energy management and other additional services based on advanced analytics.

3.2.1.4 Address conflicts of interests in energy resource planning, delivery, and regulation

The Project Team considered how useful each regulatory model is in separating planning, operational control, investment, and ownership to minimize conflicts of interests. The regulated and vertically-integrated monopoly structure of Hawaii's electricity industry can amplify the conflicts of interest in energy resource planning, delivery, and regulation. The potential for conflict of interest between or among different utility functions exists because the utilities control resource planning, grid operations, energy delivery, and a significant share of generation resources. Therefore, there is an inherent incentive in the current regulatory model for utilities to opt for a planning and operations approach that benefits their other business entities. It creates the possibility of a tilted playing field in favor of the utility because IOUs like HECO Companies have a profit-maximization objective. The primary check on the IOUs' self-interest is usually the PUC's regulatory proceedings, putting the utilities and the PUC in an adversarial arrangement.

3.2.1.5 Align stakeholder interests

Under this criterion, the different regulatory models were compared based on whether they include mechanisms that align the interests of utilities, customers, Independent Power Producers ("IPPs"), and policymakers. In any industry, stakeholders can have some interests that are mutually beneficial and others that benefit one at the expense of others. Well-designed regulations encourage behavior that falls in the former category and dissuade that which falls in the latter.

3.2.2 Criterion 2: Ensure utilities' financial health

Under this second criterion, the Project Team assessed how the different regulatory models impact the utilities' ability to earn a fair rate of return and generate additional revenues. The financial viability of the utilities is an important consideration when comparing different regulatory models. In all regulatory models, the utilities are integral parts of the system. Stakeholders (during the outreach meetings) also indicated that they expect the utilities to provide essential electric services. Modernizing Hawaii's electric grid infrastructure and achieving the State energy goals would require sizeable investments. For some of the necessary investments, the utilities remain best positioned to make those investments cost-effectively. Therefore, it is imperative to ensure that utilities can raise funds for capital needs and earn a fair return that allows them to meet their obligations and attract investors.

3.2.2.1 Provide utility the ability to earn a fair rate of return

Under this criterion, the Project Team evaluated how the change in the regulatory model would help ensure that the utilities can earn a fair rate of return. Regulatory changes that limit utilities' revenue or add financial penalties tied to performance could impact the utilities' cost of capital. The utilities' financial viability is reflected in their cost of capital, among other factors. Utilities that operate an efficient business in a stable regulatory environment have better access to capital, which could finance their expenditures. Lower levels of risks, whether real or perceived, usually translate into lower costs of capital and ultimately lower rates. The HECO Companies rely on capital markets for financing, and thus are acutely sensitive to regulatory changes that impact their ability to meet their operational mandates (as defined by the PUC) *and* provide a predictable return to their investors.

KIUC is also exposed to regulatory risks even though it can obtain debt at subsidized rates from specialty lenders and essentially raise equity *for free* (e.g., soliciting patronage capital from its members). As a co-op, KIUC relies on securing subsidized loans to lower its costs of providing service to its members. Even though the loans are subsidized, they have terms and conditions regarding, for instance, minimum levels of interest coverage. Failure to comply with debt covenants would raise its costs of debt and undermine a crucial part of its value proposition to its members.

3.2.2.2 Add opportunities to monetize new revenue streams

Aligning utility incentives with the State's priorities (such as lower electricity bills, reduced dependence on imported oil, and a greater say in utility decision-making) is often discussed in terms of removing specific incentives (for utilities), which result in a detrimental outcome for ratepayers. However, incentives can also be aligned by financially rewarding utilities for investing in or achieving outcomes that benefit the broader community. Utilities do not always benefit financially from actions that create value for the community; sometimes, their traditional revenue streams are even constrained as a result. Therefore, allowing utilities to generate incremental new revenue or providing reward opportunities for such actions would align their interests with the community while also supporting their revenues and financial viability.

Under this criterion, the Project Team assessed whether the regulatory models provide additional revenue streams or financial incentives to the utilities. For instance, PBR models offer financial incentives tied to the utilities' performance. Likewise, a DSPP model opens new categories of potential revenues for utilities. The presence and magnitude of such positive reinforcements could offset, in part or wholly, any increases in the riskiness of the utilities' operations.

3.2.3 Criterion 3: Minimize implementation costs

A change of regulatory model may result in savings on current costs in the long run but also cause additional costs during the transition to, and implementation of, the new regulatory model. Therefore, under this criterion, the regulatory models were compared based on the costs resulting from transitioning and operating the new regulatory model. Aside from the Status Quo (which would not result in incremental costs), the other eight regulatory models require varying degrees of stakeholder engagement, legislative processes, and infrastructure investments. Furthermore, a new regulatory model could also require the PUC to expand its capabilities to provide the necessary oversight.

3.2.3.1 Lower costs from transition and operations

Transitioning to a new model would requires expenditures associated with conducting the necessary studies and stakeholder engagement. Furthermore, there may be additional expenditures related to personnel and infrastructure, both initially and on an ongoing basis. This is particularly true for the IGO and DSPP models because they entail a significant change in how the grid is operated; substantial infrastructure investments and new operational capabilities are necessary to enable those models. The performance targets under PBR models also require some utility investments up-front as well as for regular monitoring and verification, all of which are crucial to the achievement of the goals.

3.2.3.2 Reduce regulatory oversight requirements

A new regulatory model may require the PUC to hire more staff (or external consultants), so it can ensure that the utilities remain in compliance with their new responsibilities. For instance, the PBR models place a significant administrative burden on the regulator, especially during the first generation of implementation. The PUC would need to put together regulatory implementation guidelines, which specify the PBR mechanisms and process. Moreover, the PUC would need to monitor the operational and financial performance of the utilities. On the other hand, the IGO and HERA entities may lower the burden on the PUC, for example, in terms of providing direct oversight on interconnections and reliability.

3.2.4 Criterion 4: Maintain stable rates

This criterion considers the volatility of electricity rates for consumers that may result from a regulatory change. Some of the models may provide rate stability while others might increase rate volatility. Rates could also change drastically between rate cases even without a significant change in regulation. For instance, rates could rise if the costs for utilities increase significantly due to substantial capital investments (e.g., for replacing infrastructure or installing new equipment), or due to the fuel prices, in certain years. One example of a mechanism for stabilizing rates without harming utility financials is to lengthen the regulatory period.

3.2.5 Criterion 5: Strengthen utility's performance

As discussed in previous working papers, the utilities are required to provide adequate and reliable electricity supply, meet the quality of service standards, avoid interruption of service, and conform to the policies set by the legislation. Incentivizing the utilities to improve their performance in these categories is one factor that was considered under this criterion.

Also, as the power sector evolves, the utilities are expected to perform new functions and offer new services. The new responsibilities could fall on the utilities or be transferred to new entities, depending on the model. Even some of the current functions of the utility could be transferred to other entities. There are technical risks in terms of how competent the different bodies are in performing the new tasks or maintaining current standards of reliability and customer service under the new regulatory structures. Therefore, another factor that was taken into account under this criterion is whether additional staffing is required to perform the new responsibilities.

3.2.5.1 Provide an adequate and reliable electricity supply

The Project Team evaluated the regulatory models based on the oversight and enforcement mechanisms within each model to ensure that the grid service continues to meet the standards set by the PUC. The General Order No. 7 (regarding Hawaii's PUC) outlined several standards for electricity service. It mandates essential metrics relevant to future regulatory models.[15] Indices

[15] Department of Regulatory Agencies, State of Hawaii. *Title VII – Public Utilities Commission. Standards for Electric Utility Service in the State of Hawaii, General Order No. 7.* Available at: https://puc.hawaii.gov/wp-content/uploads/2013/04/General-Order-7.pdf

that measure grid reliability include System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI"). Maintaining grid reliability will be more challenging as the share of intermittent renewables in the generation mix increases.

3.2.5.2 Meet quality of service standards

The regulatory models were assessed in terms of how utilities under each regulatory model would continually achieve high quality of service standards as required by the PUC. Quality of service includes aspects of customer service and technical services, which involve both interactions and engagements between customers and utilities.

3.2.5.3 Ensure adequate staffing with the required expertise

A smooth transition to the new regulatory model requires staffing with relevant skills and competencies. While it is generally reasonable to assume that there would be a transition phase between regulatory models, some models would need new technical and operational capabilities (such as a distribution-level peer-to-peer transaction platform), resulting in greater operational risk. The Project Team's prior stakeholder engagement workshops revealed concerns about the ability of the PUC and utilities to attract and retain talented staff. This concern may be exacerbated by a transition to regulatory models that are less common nationally and globally, and therefore have smaller talent pools of experienced personnel or require more rigorous training for current staff.

3.2.6 Criterion 6: Ensure legal viability

Legal viability encompasses the overall legal feasibility of each potential new regulatory model and the associated transition process. This includes changes in legislation, regulations, or additional requirements. It also assesses the extent to which the involvement of various actors—whether it be the State legislature, local city councils, or the PUC—is necessary for the establishment of the regulatory model. There may be winners and losers from the transition to a new model. Stakeholders who are dissatisfied with the new model, whether in terms of overall structure or regarding specific details, may challenge the proposed changes before the PUC or the courts.

3.2.6.1 Limit required changes in legislation or regulation

A change in the regulatory model would require varying degrees of changes in legislation or regulations. New laws or regulations may be needed to:

(1) authorize the creation of a new entity (such as an IGO);

(2) transfer oversight functions from the PUC to a new entity – e.g., transfer responsibility in monitoring of reliability to HERA;

(3) authorize the transfer of asset ownership – e.g., transfer the infrastructure needed for system planning and dispatch from utilities to an IGO); and

(4) define new ratemaking paradigms – e.g., totex approach, indexing, and building blocks approach.

If current legislation and regulations are already in place, the regulatory model would score high in this criterion.

3.2.6.2 Minimize additional legal groundwork

The timeframe for the implementation of the necessary changes also differs based on the level of support from stakeholders. It is unlikely that the legislature or the PUC would authorize major changes without eliciting feedback from stakeholders. Some of the steps required in implementing new regulatory models are more likely to face pushback from stakeholders than others. This pushback may be expressed in regulatory proceedings or even as legal challenges in the courts. Regulatory models that require extensive groundwork are more likely to face problems or delays. The Project Team ranked the regulatory models based on the expected length of legislative and regulatory processes that are required in operationalizing the model.

3.3 Weights used for each criterion

The assignment of weights depends on the relevance of the criterion to the goals of the DBEDT Study, the implication for achieving other criteria, and the value of the criterion according to stakeholders. More specifically, the rationale for assigning higher weights to some criteria are discussed below:

- **meet State energy goals (10%):** Hawaii's 100% RPS by 2045 is an ambitious goal and of great significance to the stakeholders. This is particularly evident from the Project Team's discussions with stakeholders and their commitment towards this goal. The RPS target seeks to accelerate the energy transformation in Hawaii's electricity industry. It is also a key driver of this study primarily because there is urgency regarding the role of the State's utilities in helping achieve this goal. The high weight for this category reflects the economic and environmental underpinnings of this goal – underpinnings and considerations that are unique to Hawaii.

- **maximize consumer cost savings (10%):** The ranking emphasizes the importance of lowering energy costs because Hawaii has the highest electricity rates in the United States. Moreover, stakeholders stressed the importance of this metric in their feedback. This factor is also relevant for PUC regulatory decision-making toward any potential transition in utility ownership.[16]

- **align stakeholder interests (10%):** Aligning utility interests with the concerns of ratepayers and other industry participants is one of the most critical factors driving the study of alternative regulatory models. Imposing top-down policies and regulations to address conflicts of interest can also help achieve the necessary outcomes, but a regulatory model that aligns utility incentives with community benefits is ultimately more

[16] See Appendix A, Subsection A on "Ratepayer Benefits," Hawaii Public Utilities Commission, *Order No. 33795 (Dismissing Application Without Prejudice and Closing Docket)*, available at: https://puc.hawaii.gov/wp-content/uploads/2016/07/FINAL.ORDER_.33795.Docket2015-0022.pdf.

sustainable. Such an approach can also stimulate further innovation in the industry by promoting new partnerships and attracting the participation of new players in the industry.

- **provide utility the ability to earn a fair rate of return (10%):** This category was also given the same higher weight as the previous criteria because it compares the effects of regulatory models on the utilities' ability to raise capital. Hawaii's electricity sector requires a significant amount of investments in modernizing its infrastructure to achieve the State's energy goals, irrespective of the regulatory model chosen by policymakers. The HECO Companies' Power Supply Improvement Plan estimates the necessary investments at over $13 billion in nominal dollars between now and 2045 across the three utilities.[17] The actual amount may vary somewhat depending on regulatory model but will likely be comparable. The magnitude of investments required necessitates a comparison of the impact of each model on the utilities' costs in raising or forming capital. The financial health of utilities is not only important to utility shareholders, but also to current and prospective investors in Hawaii's power sector. A financially stable and creditworthy utility helps to lower costs for IPPs from reduced off-taker risk. It also encourages energy or software companies to develop partnerships with the utility for investments or to provide grid services, similar to what is envisioned in New York.

- **lower costs from transition and operations (10%):** High implementation or transition costs can make a viable regulatory model less palatable politically even if it delivers higher benefits to ratepayers and the community over time. The costs of transition are also felt more acutely because they are concrete, current, and often constitute larger-ticket items such as consultants' fees or infrastructure costs. In contrast, the expected future benefits of a new regulatory model accrue gradually over time and have an element of uncertainty in them. Stakeholders' support for a regulatory model can quickly erode if the transition is lengthy and expensive because these costs are often felt by or passed on to ratepayers.

- **maintain stable rates (10%):** Like consumer cost savings, the ranking emphasizes lower rate volatility because of widespread support from stakeholders for including this metric. The status quo regulatory regime provides consumers with reasonably stable rates. Changes in the regulatory model would create transition costs and further uncertainty down the line regarding costs that can eventually be passed on to ratepayers. Therefore, it is essential to consider the mechanisms that each regulatory model carries so that consumers may be insulated from fluctuations in costs.

[17] Hawaiian Electric Companies. *PSIPs Update Report, Book 1.* December 23, 2016. Page 5-5 to 5-27.

Figure 4. The weighting of major and minor categories

Major Category	Minor Category	Weight - Minor	Weight - Major
Support State policy goals	Meet State energy goals	10.0%	40%
	Maximize consumer cost savings	10.0%	
	Enable a competitive distribution system	5.0%	
	Address conflicts of interest	5.0%	
	Align stakeholder interests	10.0%	
Ensure utility's financial health	Provide utility the ability to earn a fair rate of return	10.0%	15%
	Add opportunities to monetize new revenue streams	5.0%	
Minimize implementation costs	Lower costs from transition and operations	10.0%	15%
	Reduce regulatory oversight requirements	5.0%	
Maintain stable rates	Lower risk of rate volatility	10.0%	10%
Strengthen utility's performance	Provide an adequate and reliable electricity supply	5.0%	10%
	Meet quality of service standards	2.5%	
	Ensure adequate staffing with required expertise	2.5%	
Ensure legal viability	Limit required changes in legislation or regulation	5.0%	10%
	Minimize additional legal groundwork	5.0%	

3.4 Scoring mechanism

A score of 1, 2, or 3 to each of the groups was provided where 1 indicates a "poor" score, 2 indicates a "neutral" score, and 3 indicates a "positive" score. The scores are based on the results of the analyses discussed in Section 3.2.

Nevertheless, the Project Team acknowledges that each model's performance in some criteria may be subject to variability that is outside the scope of the regulatory model but informs its transition or context. Such variations could arise due to the timing, combinations, or sequence of changes implemented. In cases where it is both realistic and appropriate, the Project Team has clearly outlined all accompanying assumptions for its scoring. In cases with significant variability and plausible leeway over these factors, the Project Team typically defaults to a "neutral" score to not unduly punish or promote any model unfairly.

4 Recommended regulatory models in Honolulu, Hawaii, and Maui Counties

4.1 Recommended models

The Project Team's analysis identified the top three regulatory models that will be further evaluated in Tasks 2.3 to 2.5. These models, in order of ranking, are 1) Hybrid model, 2) Outcomes-based PBR model, and 3) Conventional PBR with Light HERA model. The detailed scores for each model and the results of the ranking analysis are illustrated in Figure 5. It is important to note that the scoring and ranking discussed in the prior section, while transparently laid out, are to a certain extent subjective. The report acknowledges this by reviewing the 3 most promising regulatory models to provide greater insight on potential alternatives.

The highest-ranking regulatory model is a **Hybrid model** that combines Outcomes-based PBR with a DSPP and an IGO. This Hybrid model scored similarly as the Outcomes-based PBR model in some criteria but was considered more favorable in terms of its ability to facilitate the achievement of State energy goals. The IGO helps to address conflicts of interest and ensure impartiality in interconnection and reliability analyses while the DSPP component supports a transition to a competitive distribution system. Although the transition costs and the likelihood of legal challenges for this model are higher (hence, it scored less favorably than the standalone model in this respect), a staggered implementation of the different components as described in Task 2.2.1 could both lower costs and smoothen the transition. Once implemented, the DSPP and IGO components also would reduce the administrative burden of PBR regime (i.e., by reducing the set of PIMs). In summary, the Hybrid model does not only score high in the specified criteria but also meets the PUC's goals in terms of having mechanisms that result in:[18]

1) greater cost control and reduced rate volatility;

2) efficient investment and allocation of resources regardless of classification as capital or operating expenses,

3) fair distribution of risks between utilities and customers; and

4) fulfillment of State policy goals.

The analysis also shows that the **Outcomes-based PBR** model is well-suited to the State of Hawaii context even as a standalone model. An expanded set of PIMs and a longer regulatory term offers greater flexibility and benefits compared to the other PBR models. However, this model of PBR has not been implemented as widely as Conventional PBR nor is it as familiar to Hawaii's stakeholders as the Light PBR. Consequently, the design and implementation of an Outcomes-

[18] Public Utilities Commission. *Order No. 35411 Instituting a Proceeding to Investigate Performance-Based Regulation*. Docket No. 2018-0088. April 18, 2018.

based PBR would involve more data collection, analyses, and monitoring requirements, likely leading to higher costs.

A combination of the **Conventional PBR with Light HERA** was also ranked favorably in the Project Team's review. It did not score as highly as the two Outcomes-Based PBR models in the first major category (support for State policy goals). However, the scoring indicates that this model would be useful in keeping rates stable. It also scores well across the board in the other major and minor categories.

The following subsections provide a detailed discussion of the rationale for the scores of each of the regulatory model based on the major and minor criteria.

Figure 5. Conclusions of the ranking analyses – Honolulu, Hawaii, and Maui Counties

Major Category	Minor Category	Weight	HERA model	IGO	DSPP	PBR			Conventional PBR + Light HERA	Outcomes-based PBR + DSPP + IGO
						Light	Conventional	Outcomes-based		
Support State policy goals	Meet State energy goals	10.0%	3	3	3	3	3	3	3	3
	Maximize consumer cost savings	10.0%	2	3	1	2	3	3	3	3
	Enable a competitive distribution system	5.0%	1	3	3	1	1	2	1	3
	Address conflicts of interest	5.0%	2	3	2	1	1	2	2	3
	Align stakeholder interests	10.0%	2	2	2	2	3	3	3	3
Ensure utility's financial health	Provide utility the ability to earn a fair rate of return	10.0%	2	1	2	2	2	2	2	2
	Add opportunities to monetize new revenue streams	5.0%	1	1	3	2	2	3	2	3
Minimize implementation costs	Lower costs from transition and operations	10.0%	2	1	1	3	2	1	2	1
	Reduce regulatory oversight requirements	5.0%	3	2	1	2	1	1	1	1
Maintain stable rates	Lower risk of rate volatility	10.0%	2	1	1	2	3	2	3	2
Strengthen utility's performance	Provide an adequate and reliable electricity supply	5.0%	3	3	2	3	3	3	3	3
	Meet quality of service standards	2.5%	3	2	2	3	3	3	3	3
	Ensure adequate staffing with required expertise	2.5%	2	1	1	3	2	2	2	1
Ensure legal viability	Limit required changes in legislation or regulation	5.0%	3	1	1	3	2	2	2	1
	Minimize additional legal groundwork	5.0%	2	1	1	2	2	1	2	1
Summary of Major Categories	**Support State policy goals**	**40.0%**	**0.85**	**1.10**	**0.85**	**0.80**	**1.00**	**1.10**	**1.05**	**1.20**
	Ensure utility's financial health	**15.0%**	**0.25**	**0.15**	**0.35**	**0.30**	**0.30**	**0.35**	**0.30**	**0.35**
	Minimize implementation costs	**15.0%**	**0.35**	**0.20**	**0.15**	**0.40**	**0.25**	**0.15**	**0.25**	**0.15**
	Maintain stable rates	**10.0%**	**0.20**	**0.10**	**0.10**	**0.20**	**0.30**	**0.20**	**0.30**	**0.20**
	Strengthen utility's performance	**10.0%**	**0.28**	**0.23**	**0.18**	**0.30**	**0.28**	**0.28**	**0.28**	**0.25**
	Ensure legal viability	**10.0%**	**0.50**	**0.20**	**0.20**	**0.50**	**0.40**	**0.30**	**0.40**	**0.20**
Overall Score			**0.53**	**0.55**	**0.46**	**0.53**	**0.58**	**0.59**	**0.60**	**0.62**
Rank			**6**	**5**	**8**	**7**	**4**	**3**	**2**	**1**

Note:

Scoring System

Good	3
Neutral	2
Poor	1

* by default, all entries are ranked as Neutral, with Good or Poor scores assigned only with justification.

Ranking System

1 – Most favorable model and 8 - Least favorable model

4.2 Scoring rationale

The Project Team provides additional description below of the positive/neutral/poor scoring criteria and rationale for scoring of the different regulatory models by each minor category.

4.2.1 Support State policy goals

For the State's energy goals, the Project Team's analysis concludes that all the models would be able to facilitate the achievement of the RPS requirement, provided that certain conditions and assumptions, such as sound implementation and regulation, are met. However, the models differ in how cost effective they are for consumers and how closely they align utility interests with those of stakeholders.

- **Ability to meet State energy goals**

Ranking	Description	Scoring
Positive	Expected to achieve target RPS by 2045	• All regulatory models
Neutral	Business as usual	• None
Poor	Unlikely to achieve target RPS by 2045	• None

All models ranked positively because they are expected to facilitate the achievement of the target RPS.

- **Maximize consumer cost savings**

Ranking	Description	Scoring
Positive	Electricity bills expected to decrease	• IGO, • Conventional PBR • Outcomes-based PBR • Conventional PBR with Light HERA • Hybrid
Neutral	Business as usual	• HERA model • Light HERA
Poor	Electricity bills expected to increase due to high costs of transition	• DSPP

The IGO, Conventional PBR, Outcomes-based PBR, DSPP, and the two hybrid models are most likely to lower costs for consumers over time and therefore ranked positively in this category. The IGO model helps to reduce the costs of energy for consumers through greater competition and closer integration of DERs with the bulk power system. The DSPP model may require high transition costs but could offer cost savings in the long run by fostering more active distribution markets. The two Conventional PBR models control costs to ratepayers through revenue caps on utilities. The Outcomes-based PBR model

lowers costs through specific performance targets; in the hybrid model, the incentives are magnified by the IGO. The HERA model would likely result in similar energy costs as the status quo and is thus given a neutral score.

- **Enable a competitive distribution system**

Ranking	Description	Scoring
Positive	Facilitates a transition to distribution-level markets	• IGO • DSPP • Hybrid
Neutral	Greater connection of DERs and design of suitable outcomes or incentives	• Outcomes-based PBR
Poor	No movement towards distribution-level transactions	• HERA model • Light PBR • Conventional PBR • Conventional PBR with Light HERA

Distribution-level markets are only expected to develop under IGO and DSPP models in all four counties. Hence, these models were ranked positively. In the HECO Companies' territory, this includes the hybrid model. None of the other models have any specific mechanism that could facilitate this development although the Outcomes-based PBR model could incorporate specifically targeted outputs and incentives for DER interconnection or distribution market activity/volume. Therefore, the Outcomes-based PBR model scored neutral while the others were ranked poorly.

- **Address conflicts of interest**

Ranking	Description	Scoring
Positive	Effectively separates resource planning, grid operation, and asset ownership	• IGO • Hybrid
Neutral	Some separation of functions	• HERA model • DSPP • Outcomes-based PBR • Conventional PBR with Light HERA
Poor	Same entity is responsible for the majority of grid functions	• Light PBR • Conventional PBR

For the three counties with vertically-integrated IOUs, the two models with an IGO entity can separate the planning and operations of the grid functions. An IGO would oversee resource planning and dispatch, therefore, breaking the potential for utility bias in its planning and dispatch functions. Thus, the IGO and the Hybrid models received a

positive score in this category. Light PBR and Conventional PBR models achieved the least amount of separation of planning and operation and received a poor score. Outcomes-based PBR is more effective in leveling the playing field through expanded PIMs and therefore received a neutral rating.

- **Align stakeholder interests**

Ranking	Description	Scoring
Positive	Interests align	• Conventional PBR • Outcomes-based PBR • Conventional PBR with Light HERA • Hybrid
Neutral	Interests are somewhat aligned	• HERA model • IGO • DSPP • Light PBR
Poor	Interests clash	• None

The different variants of PBR models include PIMs and ESMs that help align the interests of utilities and stakeholders in the HECO Companies' territories. Therefore, the PBR models were ranked as positive. The other models were given a neutral score since they would help to partially improve the alignment of the stakeholder interests.

4.2.2 Ensure utility's financial health

The net impact on utility finances is positive for DSPP and PBR models including hybrids. The business and regulatory risks increase under these models because of greater uncertainty about their implementation (especially in the case of DSPP), the potential for unforeseen costs, and risk of financial penalties in the case of the PBR models. However, these risks are offset by the fact that utilities do have the ability to expand their revenue streams.

- **Provide utility the ability to earn a fair rate of return**

Ranking	Description	Scoring
Positive	Lowest levels of risks for utility revenues	• None
Neutral	Some downside risk balanced with upside potential	• HERA model • DSPP • Light PBR • Outcomes-based PBR • Hybrid • Conventional PBR • Conventional PBR with Light HERA

Poor	High risk with little upside	• IGO

All the regulatory models under consideration are likely to increase risks relative to the status quo and therefore result in higher costs of capital for the HECO Companies. The IGO model represents the highest risk for current investors in Hawaii's utilities and therefore received a score of 1 (or poor). For instance, under the IGO model, utilities lose control over long-term resource planning and dispatch. This creates the potential for stranded utility generation assets, particularly for the old and inefficient plants. The other models were given a neutral rank.

- **Bring opportunities to monetize new revenue streams**

Ranking	Description	Scoring
Positive	New revenue streams available to utilities	• DSPP • Outcomes-based PBR • Hybrid
Neutral	Restricted possibility for additional revenue	• Light PBR • Conventional PBR • Conventional PBR with Light HERA
Poor	No additional revenue opportunities	• HERA model • IGO

DSPP and the PBR models (standalone and hybrid) offer the IOUs an opportunity to expand their earnings and thus provided with a positive rank under this criterion. The DSPP model includes platform-service revenues for the utility, through which they could generate fee revenues from third-party service providers. The PBR model comprises extensive performance incentives, enabling utilities to increase their returns by surpassing the targets set. The HERA and IGO models do not include mechanisms for incremental earnings and therefore got a poor score.

4.2.3 Minimize implementation costs

The HERA and Light PBR models entail a limited set of changes relative to the status quo, thus, have the lowest costs of transition for the three IOUs. They are most straightforward to implement, familiar to current stakeholders and do not require a regulatory overhaul.

- **Lower costs from transition and operations**

Ranking	Description	Scoring
Positive	Low costs of transition	• Light PBR
Neutral	Some costs of transition	• HERA model • Conventional PBR • Conventional PBR with Light HERA

Poor	Implementation of a new model likely to entail an expensive and lengthy process	• IGO • DSPP • Outcomes-based PBR • Hybrid

IGO, DSPP, and the two Outcomes-based PBR models in the HECO Companies' territories rank poorly in this category as they involve high costs of transition for different reasons. IGO requires transferring system planning and dispatch infrastructure from the current utilities to the new entity; the needed support involves both hardware and software. Moreover, there may also be a transfer of personnel. As mentioned previously, costs of transition for the DSPP model are not fully known and are likely to be high. Likewise, implementation of the Outcomes-based PBR models would likely entail extensive studies that can help define the desired outcomes clearly with their corresponding performance targets and financial incentives/penalties. Furthermore, these models must also address consumer concerns about the complexity of the structure.

On the other hand, implementing the Light PBR model would involve predictable and mostly understood costs and processes. The transition would also be relatively simple for the HERA model. Therefore, these two regulatory models ranked positively in this criterion.

- **Reduce regulatory oversight requirements**

Ranking	Description	Scoring
Positive	PUC has the required expertise and personnel	• HERA model
Neutral	Small changes in PUC oversight	• IGO • Light PBR
Poor	Expanded breadth and complexity of issues overseen by the PUC	• DSPP • Conventional PBR • Outcomes-based PBR • Conventional PBR with Light HERA • Hybrid

The HERA model ranked positively in this criterion because it requires the smallest changes in the PUC's scope of responsibilities. Even though there is a new entity created, its independence helps to lessen the adversarial nature of PUC oversight.

DSPP and the standalone and hybrid variants of the PBR models (except the Light PBR model) ranked poorly as they would significantly increase the responsibilities of the PUC. Due to the inherent complexity of the DSPP model, the PUC must directly oversee its design and implementation. The lack of examples in other jurisdictions only imposes more burden on the PUC. Likewise, the PBR models also demand a more active role of the PUC in defining outcomes, setting targets, and ensuring compliance. The other models

(IGO and Light PBR) were ranked neutral as the regulatory oversight of the PUC would remain relatively the same.

4.2.4 Provide stable rates

Ranking	Description	Scoring
Positive	Includes stronger mechanisms to stabilize rates	• Conventional PBR • Conventional PBR with Light HERA
Neutral	Some rate stability – status quo	• HERA model • Light PBR • Outcomes-based PBR • Hybrid
Poor	Ratepayers are likely to face fluctuating prices	• IGO • DSPP

Conventional PBR models—both standalone and hybrid—have the most stable rates because they feature fixed regulatory period and forecasted rates. Thus, they ranked positively in this criterion.

Although the Outcomes-based PBR models also have a fixed regulatory period and set rates, they have a longer regulatory term of five years and feature a more comprehensive set of PIMs that could impact the rates paid by consumers for the next regulatory period. Therefore, there is a risk that rates would fluctuate in the subsequent regulatory period. As such, the Outcomes-Based PBR received a neutral score.

The IGO and DSPP models introduce more significant exposure to market dynamics as well as unknown elements of costs, all of which suggest a tendency toward greater rate volatility. Thus, they were given a poor score.

4.2.5 Strengthen utility's performance

- **Provide an adequate and reliable electricity supply**

Ranking	Description	Scoring
Positive	Expected to ensure reliable electric service	• HERA model • IGO • Light PBR • Conventional PBR • Outcomes-based PBR • Conventional PBR with Light HERA • Hybrid
Neutral	Generally reliable with some risk of disruptions	• DSPP
Poor	Unlikely to provide reliability	• None

A distribution-level market platform that is separate from bulk electricity has some risk of disruptions especially because a full-fledged implementation does not exist. Therefore, the DSPP model scored neutral in this criterion.

When DSPP is combined with Outcomes-based PBR and IGO under the Hybrid model, the incentives under PBR and the IGO's mandates would ensure reliability. Therefore, the Hybrid model scored positively.

All other models are expected to provide reliable electric service and thus, given a positive score.

- **Meet quality of service standards**

Ranking	Description	Scoring
Positive	Prompt and responsive customer service	• HERA model • Light PBR • Conventional PBR • Outcomes-based PBR • Conventional PBR with Light HERA • Hybrid
Neutral	Business as usual	• IGO • DSPP
Poor	Low priority is given to customer service	• None

All models except the IGO and DSPP models are expected to perform better in this criterion and thus scored positively. The IGO and DSPP models are less likely to result in better quality customer service because utilities in these models have less control over the electricity system. Although the IGO could provide its own customer service and would improve interconnection, the utility is expected to remain the customer-facing entity in this structure. As a result, customers may be somewhat unsatisfied if the utilities are unable to resolve or answer all of their issues. For this reason, these models were scored neutral under this criterion.

- **Ensure adequate staffing with the required expertise**

Ranking	Description	Scoring
Positive	Utilities and other entities have the required expertise and personnel	• Light PBR
Neutral	Small changes in staffing requirements	• HERA model • Conventional PBR • Outcomes-based PBR • Conventional PBR with Light HERA

Poor	Hiring of lots of expert personnel	• IGO • DSPP • Hybrid

Utilities could likely meet their operational requirements with their current personnel under the Light PBR model. This model involves expansion of the PIMs, which current staff can implement. Hence, the Light PBR ranked positively under this category.

On the other hand, IGO, DSPP, and the Hybrid models would expand hiring needs and scored poorly in this criterion The IGO entity requires staff with the necessary expertise so that it can perform its functions; not all of its hiring needs can be met with a transfer of personnel from the current utilities. Greater technological expertise is also needed to implement the complex transactions and software platforms necessary for a DSPP model.

4.2.6 Ensure legal viability

- **Limited required changes in legislation or regulation**

Ranking	Description	Scoring
Positive	Requires no (or minor) regulatory action and no legislative action	• Light PBR • HERA model
Neutral	Requires regulatory action but no legislative action	• Conventional PBR • Outcomes-based PBR • Conventional PBR with Light HERA
Poor	Requires both regulatory and legislative action	• IGO • DSPP • Hybrid

The Light PBR model and HERA model could be implemented in the HECO Companies' territories through a minor regulatory proceeding to expand the PIMs and add rewards and penalties and to list the responsibilities of the HERA, respectively. It could be implemented with only minor regulatory changes and was thus ranked positively.

In contrast, the models involving IGO and DSPP (including the combined hybrid model) ranked poorly in this category as they require accompanying legislative and regulatory action that would authorize the creation of the new entities and define the industry structure.

- **Minimize additional legal groundwork**

Ranking	Description	Scoring
Positive	Little risk of legal challenges from stakeholders	• None
Neutral	Moderate risk of legal challenges from stakeholders	• HERA model • Light PBR

		• Conventional PBR • Conventional PBR with Light HERA
Poor	Major risk of legal challenges from stakeholders	• IGO • DSPP • Outcomes-based PBR • Hybrid

All regulatory models under consideration for the three IOU counties entail detailed work—including with legal teams that would help define the new regulatory structures—and therefore carry some risk of legal challenges from stakeholders.

The risk is higher for IGO, DSPP, Outcomes-based PBR, and hybrid model that combines all three. Utilities are likely to resist a transition to an IGO or DSPP structure because it is most disruptive to their vertically-integrated operations. Because of this, these models ranked poorly under this criterion.

5 Recommended regulatory models in Kauai County

5.1 Recommended models

The Project Team also conducted a similar analysis separately for Kauai County, owing to its different ownership structure (co-op) and preferences indicated by its stakeholders. Instead of the hybrid models evaluated for the HECO Companies, the Project Team included a Lighter PUC Regulation model in addition to the four regulatory models. The top three regulatory models for Kauai County, in order of ranking, excluding the Status Quo, are 1) HERA model, 2) IGO, and 3) Lighter PUC Regulation. The detailed scores for each model and the results of the ranking analysis are shown in Figure 6. As mentioned previously, it is important to note that the scoring and ranking are subjective to a certain extent. Therefore, the report acknowledges this by casting a wider net and reviewing the 3 most promising regulatory models for further analyses.

The **HERA model** ranked the highest among the regulatory models due to its potential to support the State policies, strengthen the utility's performance, and legal viability. Under this model, KIUC would maintain its current structure as a co-op. Its member-owned structure can intrinsically align interests between ratepayers (or the interests of the majority) and the utility. It has access to subsidized debt that allows it to provide grid services to ratepayers while controlling costs.

Compared to the HERA model, the **IGO model** would incur significant transition costs. It also increases the likelihood of rate volatility and would require substantial legal work to implement. However, it is more likely to result in increased competition at the distribution level.

Modifying the PUC's current regulatory oversight over KIUC to a "lighter-touch" approach—the **Lighter PUC Regulation model**—can deliver even more savings to the customer-members. This model decreases the regulatory costs for KIUC by granting it greater autonomy. However, the Project Team's analysis finds that removing direct PUC oversight may create risks in the implementation of State goals as enacted by the Governor and legislature. Furthermore, this model also scores lower in terms of legal feasibility because it does not have sufficient safeguards against the management of conflict of interest, short-term decision-making (that have negative impacts in the long term) by the KIUC Board, and disputes between KIUC leadership and a minority of its members.

The following subsections provide a detailed discussion of the rationale for the scores of each of the regulatory models based on the major and minor criteria.

Figure 6. Conclusions of the ranking analyses – Kauai County

Major Category	Minor Category	Weight	Status Quo with HERA	IGO	DSPP	Lighter PUC Regulation
Support State policy goals	Meet State energy goals	10.0%	3	3	3	1
	Maximize consumer cost savings	10.0%	2	3	1	3
	Enable a competitive distribution system	5.0%	1	3	3	1
	Address conflicts of interest	5.0%	3	3	3	2
	Align stakeholder interests	10.0%	3	2	2	2
Ensure utility's financial health	Provide utility the ability to earn a fair rate of return	10.0%	2	2	1	3
	Add opportunities to monetize new revenue streams	5.0%	1	2	3	1
Minimize implementation costs	Lower costs from transition and operations	10.0%	2	1	1	3
	Reduce regulatory oversight requirements	5.0%	1	1	1	3
Maintain stable rates	Lower risk of rate volatility	10.0%	2	1	1	2
Strengthen utility's performance	Provide an adequate and reliable electricity supply	5.0%	3	3	2	3
	Meet quality of service standards	2.5%	3	2	2	2
	Ensure adequate staffing with required expertise	2.5%	2	1	1	3
Ensure legal viability	Limit required changes in legislation or regulation	5.0%	3	1	1	2
	Minimize additional legal groundwork	5.0%	2	1	1	2
Summary of Major Categories	**Support State policy goals**	**40.0%**	**1.00**	**1.10**	**0.90**	**0.75**
	Ensure utility's financial health	**15.0%**	**0.25**	**0.30**	**0.25**	**0.35**
	Minimize implementation costs	**15.0%**	**0.25**	**0.15**	**0.15**	**0.45**
	Maintain stable rates	**10.0%**	**0.20**	**0.10**	**0.10**	**0.20**
	Strengthen utility's performance	**10.0%**	**0.28**	**0.23**	**0.18**	**0.28**
	Ensure legal viability	**10.0%**	**0.50**	**0.20**	**0.20**	**0.40**
Overall Score			**0.57**	**0.56**	**0.47**	**0.51**
Rank			**1**	**2**	**4**	**3**

Note:

Scoring System	
Good	3
Neutral	2
Poor	1

* by default, all entries are ranked as Neutral, with Good or Poor scores assigned only with justification.

Ranking System

1 – Most favorable model and 4 - Least favorable model

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5.2 Scoring rationale

5.2.1 Support State policy goals

- **Ability to meet State energy goals**

Ranking	Description	Scoring
Positive	Expected to achieve target RPS by 2045	• HERA model • IGO • DSPP
Neutral	Business as usual	• None
Poor	Unlikely to achieve target RPS by 2045	• Lighter PUC Regulation

All models, except for the Lighter PUC Regulation model, are expected to facilitate the achievement of the target RPS. The Lighter PUC Regulation model was scored as poor because the PUC and other State entities has less direct control over the utility in implementing State policies and in directing the utility toward targets associated with State goals.

- **Maximize consumer cost savings**

Ranking	Description	Scoring
Positive	Electricity bills expected to decrease	• IGO • Lighter PUC Regulation
Neutral	Business as usual	• HERA model
Poor	Electricity bills expected to increase	• DSPP

- The IGO and Lighter PUC Regulation models all result in lower costs to consumers and as such scored positively in this category. The IGO model can pass on the savings generated from increased competition. Meanwhile, the Lighter PUC Regulation model also lowers the expenses of regulatory proceedings that consumers have to bear ultimately. The HERA model is ranked neutral because any additional costs associated with the HERA entity is expected to be minimal relative to overall utility costs. The DSPP model is ranked poor due to high implementation costs.

- **Enable a competitive distribution system**

Ranking	Description	Scoring
Positive	Facilitates a transition to distribution-level markets	• IGO • DSPP
Neutral	Greater connection of DERs	• None
Poor	No movement towards distribution-level transactions	• HERA model • Lighter PUC Regulation

Under IGO and DSPP models, distribution-level markets are expected to be developed. Thus, these models ranked positively. The other models would be less able to foster a competitive distribution system and thus scored poorly.

- **Address conflicts of interest**

Ranking	Description	Scoring
Positive	Effectively separates resource planning, grid operation, and asset ownership	• HERA model • IGO • DSPP
Neutral	Some separation of functions	• Lighter PUC Regulation
Poor	Same entity is responsible for the majority of grid functions	• None

HERA and IGO models scored positively in addressing conflicts of interests as these models include an independent entity (such as the PUC, IGO, and HERA) that ensures fairness in interconnection or dispatch. The IGO model also separates system planning, resource planning, system operations, and dispatch functions from the utility. The DSPP model helps to resolve conflicts by altering the utility's business model and ensuring it can benefit from greater participation of customers and third parties in distribution markets. The Lighter PUC Regulation model is given a neutral score because it makes PUC oversight more difficult, for example, in cases when there is a need to settle disputes and grievances in the co-op. It also does not introduce any separations in utility functions from the current vertically-integrated structure.

- **Align stakeholder interests**

Ranking	Description	Scoring
Positive	Interests align	• HERA model
Neutral	No relation between utility and ratepayer interests	• IGO • DSPP • Lighter PUC Regulation
Poor	Interests clash	• None

The HERA model ranked positively in this category because of the presence of a regulatory body that provides oversight of the regulated entities to ensure that the customers are served fairly and efficiently and ensures that utilities are financially viable. The other models ranked neutral.

5.2.2 Ensure utility's financial health

- **Provide utility the ability to earn a fair rate of return**

Ranking	Description	Scoring

Positive	Lowest levels of risks for utility revenues	• Lighter PUC Regulation
Neutral	Some downside risk balanced with upside potential	• HERA model • IGO
Poor	High risk with little upside	• DSPP

The financial aspects are different for KIUC because of its co-op structure. It raises equity capital from its members in the form of patronage capital, which it retires periodically by crediting the amount back to its members. KIUC's financial health depends on its ability to control expenditures, which can be achieved through the Lighter PUC Regulation model, which was therefore ranked positively. The DSPP model is likely to add the greatest strain on KIUC finances because of unpredictable infrastructure needs. Even though it could lower costs in the long run, the likely transition costs and risks are at odds with the cost minimization approach emphasized by KIUC and its lenders. The DSPP model thus scored poorly in this criterion. On the other hand, the IGO model is ranked as neutral despite the likelihood of significant transition costs because IGO operations are well understood and thus carry low risks.

- **Bring opportunities to monetize new revenue streams**

Ranking	Description	Scoring
Positive	New revenue streams available to utilities	• DSPP
Neutral	Restricted possibility for additional revenue	• IGO
Poor	No additional revenue opportunities	• HERA model • Lighter PUC Regulation

On Kauai County, only the DSPP model can definitely support incremental revenue generation for the utility from distribution market activity and platform services. A more seamless integration of DERs and bulk power in one system under the IGO model could create potential earning opportunities for the utility as the owner of all wire assets. However, such revenues would likely be defined by the IGO and would also depend on the IGO's market rules. Therefore, this model was ranked neutral. HERA and IGO models are ranked poorly as they do not provide additional revenue opportunities for the co-op. The Lighter PUC Regulation would reduce regulatory expenses but would not change utility revenues. The HERA model simply adds a separate oversight body, which could add some costs to the utility but would not alter its revenue streams.

5.2.3 Minimize implementation costs

- **Lower costs from transition and operations**

Ranking	Description	Scoring
Positive	Low costs of transition	• Lighter PUC Regulation

Neutral	Some costs of transition	• HERA model
Poor	Implementation of a new model likely to entail an expensive and lengthy process	• IGO • DSPP

All regulatory models except the Status Quo involve some transition costs. More specifically, the IGO and DSPP models require significant investments in implementation and thus ranked poorly under this category.

The Lighter PUC Regulation model also requires some legislative enactments, but this is offset by a decrease in its ongoing regulatory expenses. Therefore, the Lighter PUC Regulation model received a positive score.

- **Reduce regulatory oversight requirements**

Ranking	Description	Scoring
Positive	PUC has the required expertise and personnel	• Lighter PUC Regulation
Neutral	Small changes in PUC oversight	• None
Poor	Expanded breadth and complexity of issues overseen by the PUC	• DSPP • HERA model • IGO

As the name suggests, only the Lighter PUC Regulation model reduces regulatory oversight of KIUC and hence, it received a positive score. Regulatory models such as HERA, IGO, and DSPP require additional regulatory oversight and thus ranked poorly.

5.2.4 Maintain stable rates

Ranking	Description	Scoring
Positive	Includes stronger mechanisms to stabilize rates	• None
Neutral	Some rate stability – status quo	• HERA model • Lighter PUC Regulation
Poor	Ratepayers are likely to face fluctuating prices	• IGO • DSPP

The IGO and DSPP models are ranked poorly because they are expected to increase rate volatility in Kauai County. Both models entail significant transition costs, which would likely be reflected at least partially in electricity rates. Even after the models are established, rates would be more susceptible to competitive forces, market rules established by the IGO, or future growth in platform-based services that the utility could monetize under the DSPP model. Utility operations under the HERA and Lighter PUC Regulation models are unlikely to change significantly and therefore not likely to impact rate volatility. The two models thus scored neutral.

5.2.5 Strengthen utility's performance

- **Provide an adequate and reliable electricity supply**

Ranking	Description	Scoring
Positive	Expected to ensure reliable electric service	• HERA model • IGO • Lighter PUC Regulation
Neutral	Generally reliable with some risk of disruptions	• DSPP
Poor	Unlikely to provide reliability	• None

The DSPP model ranked neutral as it carries some risk of interruptions in electric service. A distribution-level market platform that is separate from bulk electricity carries some risk of disruptions especially because a full-fledged implementation does not exist. All other models are expected to provide reliable electric service and thus, scored positively.

- **Meet quality of service standards**

Ranking	Description	Scoring
Positive	Prompt and responsive customer service	• HERA model
Neutral	Business as usual	• IGO • DSPP • Lighter PUC Regulation
Poor	Low priority is given to customer service	• None

The HERA model is ranked positively because of the presence of an additional oversight body. The IGO and DSPP models are less likely to result in quality customer service because the co-op has less control over some components of the electricity system. Furthermore, third parties may also provide some customer and grid services under the DSPP model. As a result, these two models garnered a neutral score.

The Lighter PUC Regulation model for KIUC also carries some risk when it comes to customer service—for example, there is no other regulatory body other than the KIUC Board ensuring that services are provided reliably and safely. Therefore, this model ranked neutral due to lack of direct oversight from an entity other than the co-op Board.

- **Ensure adequate staffing with the required expertise**

Ranking	Description	Scoring
Positive	Utilities and other entities have the required expertise and personnel	• Lighter PUC Regulation

Neutral	Small changes in staffing requirements	• HERA model
Poor	The hiring of lots of expert personnel	• IGO • DSPP

The Lighter PUC Regulation model does not impact staffing needs for KIUC and thus received a positive score. The HERA model requires the creation of an independent body but was ranked neutral because it is likely to be a small body and the necessary expertise already exists. On the other hand, DSPP and IGO models require significant expertise and new capabilities and therefore rank poorly in this category.

5.2.6 Ensure legal viability

- **Limited required changes in legislation or regulation**

Ranking	Description	Scoring
Positive	Requires no regulatory or legislative action	• HERA model
Neutral	Requires minor regulatory action but no legislative action	• Lighter PUC Regulation
Poor	Requires both regulatory and legislative action	• IGO • DSPP

Major legislative or regulatory changes are not required for the Status Quo and HERA models in Kauai County, and therefore they received a positive score. On the other hand, the Lighter PUC Regulation model for KIUC requires some legislative changes while the IGO and DSPP models need much more legislative or regulatory change.

- **Minimize additional legal groundwork**

Ranking	Description	Scoring
Positive	Little risk of legal challenges from stakeholders	• None
Neutral	Moderate risk of legal challenges from stakeholders	• HERA model • Lighter PUC Regulation
Poor	Major risk of legal challenges from stakeholders	• IGO • DSPP

The IGO and DSPP models ranked poorly under this category as they require significant legal work in Kauai County. Although there is already a regulation enabling HERA, there is still additional legal groundwork needed to implement it. Accordingly, the HERA model ranked neutral in this regard. The Lighter PUC Regulation model is also ranked neutral since it requires some redrafting of rules and clear guidance on KIUC's obligations and what can trigger "re-regulation" if KIUC fails to meet those obligations.

6 Appendix A: Scope of work to which this deliverable responds

Task 2.2.6 Identification and recommendation for the three most beneficial regulatory models for further consideration.

CONTRACTOR shall identify and recommend three feasible regulatory models for further consideration.

DELIVERABLE FOR TASK 2.2.6. CONTRACTOR shall provide its conclusions and all work to make recommendations on the three most beneficial models for further consideration. The CONTRACTOR compares models to identify the top three models that merit additional analyses. The remaining tasks in TASK 2 shall be conducted for the top three models. CONTRACTOR shall provide a written description of the analysis in MS Word and an MS Excel spreadsheet. CONTRACTOR shall submit deliverable for TASK 2.2.6 to the STATE for approval.

7 Appendix B: List of works consulted

"Division of Consumer Advocacy's Direct Testimonies and Exhibits," Division of Consumer Advocacy, Docket No. 2015-0022, August 10, 2015, https://cca.hawaii.gov/dca/files/2015/08/2015-0022-CA-DT-and-Exhibits-PUBLIC.pdf

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Hawaii Public Utilities Commission, "Exhibit A: Commission's Inclinations on the Future of Hawaii's Electric Utilities," Docket No. 2012-0036, Decision and Order No. 32052, filed on April 28, 2 014, ("Order No. 32052"), available at https://puc.hawaii.gov/wp-content/uploads/2014/04/Commissions-Inclinations.pdf.

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The Steps, Costs, Timeline, Legal Changes, and Risks for Establishing the Recommended Regulatory Models

Working paper prepared by London Economics International LLC for the State of Hawaii with support from Meister Consultants Group, a Cadmus Company

January 8, 2019

London Economics International LLC, together with Meister Consultants Group, a Cadmus Company ("the Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State's efforts to achieve its energy goals. As part of this engagement, this working paper provides a discussion of costs, steps, timelines, legal considerations, and risks for the three highest ranked regulatory models from Task 2.2.6: (i) Outcomes-based Performance-based Regulation ("PBR"), (ii) Conventional PBR with Light HERA, and (iii) a Hybrid Model that combines Outcomes-based PBR, a Distributed System Platform Provider ("DSPP") and an Independent Grid Operator ("IGO"). These tasks respectively correspond with Tasks 2.3.1, 2.3.2, and 2.3.3 of the study. To describe the steps and timeline, the Project Team reviewed existing literature on these regulatory models, outlined key tasks involved for each model, and estimated the time necessary for individual steps for establishment and operation. To assess the costs, the Project Team evaluated the costs incurred by utilities in other jurisdictions that previously made such regulatory shifts as those contemplated by this study. For legal considerations, the Project Team researched the legal requirements and legal changes for the establishment, funding, and operation of each regulatory model. Finally, the Project Team describe the likelihood and magnitude of the operational and financial risks faced by both ratepayers and shareholders for each regulatory model.

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List of acronyms

AUC	Alberta Utilities Commission
BCA	Benefit Cost Analysis
CA	California
CAISO	California Independent System Operator
CFR	Code of Federal Regulations
COS	Cost of Service
D&O	Decision and Order
DBEDT	Department of Business, Economic Development & Tourism
DER	Distributed Energy Resources
DG	Distributed Generation
DPS	Department of Public Service
DSIP	Distributed System Implementation Plan
DSPP	Distributed System Platform Provider
ECAC	Energy Cost Adjustment Clause
EIS	Environmental Impact Statement
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
ESM	Earnings Sharing Mechanism
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FR	Federal Register
FY	Fiscal Year
GEMS	Green Energy Market Securitization Program

GW	Gigawatt
GWh	Gigawatt Hour
HAR	Hawaii Administrative Rules
HB	House Bill
HECO	Hawaiian Electric Company
HEI	Hawaiian Electric Industries
HELCO	Hawaiian Electric Light Company
HERA	Hawaii Electricity Reliability Administrator
HGIA	Hawaii Green Infrastructure Authority
HI	Hawaii
HRS	Hawaii Revised Statutes
IGO	Independent Grid Operator
IPP	Independent Power Producer
IRP	Integrated Resource Planning
ISO	Independent System Operator
KIUC	Kauai Island Utility Cooperative
kW	Kilowatt
kWh	Kilowatt Hour
LEI	London Economics International
MM	Million
MCG	Meister Consultants Group, a Cadmus Company
MECO	Maui Electric Company
MW	Megawatt
MWh	Megawatt Hour

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NERA	National Economic Research Associates, Inc.
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NY	New York
NY REV	New York's Reforming the Energy Vision
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYPP	New York Power Pool
NYSRC	New York State Reliability Council
Ofgem	Office of Gas and Electricity Markets
PBR	Performance Based Regulation
PCS	New York Public Service Commission
PIMs	Performance Incentive Mechanisms
PPAC	Purchase Power Adjustment Clause
PSIP	Power Supply Improvement Plan
PSL	Public Service Law
PUC	Public Utilities Commission
PV	Photovoltaics
REV	Reforming the Energy Vision
RIIO	Revenue = Incentives + Innovation + Outputs
RPI-X	Retail Price Index ("RPI") minus energy efficiency savings ("X")
RPS	Renewable Portfolio Standard
RSWG	Reliability Standards Working Group
RTO	Regional Transmission Organization

SAIC	Science Applications International Corporation
SAIDI	System Average Interruption Duration Index
SAIFI	Average Interruption Frequency Index
SB	Senate Bill
T&D	Transmission and Distribution
TIS	Texas Interconnect System
Totex	Total Expenditure
TFP	Total Factor Productivity
TW	Terawatt
TWh	Terawatt Hour
TX	Texas
UK	United Kingdom
US	United States
USC	United States Code

1 Executive summary

In Task 2.2.3 and 2.2.6, the Project Team provided a high-level overview of the legal, technical, and financial feasibility of five regulatory models and ranked them according to those criteria. The three highest ranking models from this analysis were the *Outcomes-based Performance-based Regulation ("PBR"), Conventional PBR with Light HERA,* and a *Hybrid Model.* Definitions of each of these regulatory models, as well as the Status Quo, are outlined in each of the "key conclusions" paragraphs below. In this subsequent working paper intended to cover Task 2.3.1, 2.3.2, and 2.3.3, the Project Team analyzes each of these regulatory models with regards to the following topics:

- The steps, timeline, and costs required to change from the current regulatory model and establish the recommended regulatory models;
- Legal steps or regulatory and legislative changes necessary to implement the recommended regulatory models; and
- Financial and operational risks for ratepayers and shareholders. For the risks, the Project Team categorizes such risks in terms of its overall *impact* and *probability* in tiers of low, low-medium, medium, medium-high, and high.

The Status Quo regulatory model is the regulatory model currently in use in Hawaii. It is characterized by use of traditional cost of service ("COS") regulation plus some light performance incentive mechanisms. Under this regulatory model which features a capex approach, the PUC sets rates that permit the utilities to recover the costs they incurred to provide service, plus a return on investment, so long as the costs are considered to be just and reasonable. The key conclusions of the Status Quo regulatory model include the following:

- The Status Quo regulatory model, by definition, requires no *steps*, *costs*, or *legal changes* to be implemented. In effect, the Status Quo regulatory model preserves regulation under a traditional cost of service regulation.
- In terms of potential *risks*, the Status Quo provides a conflict between the interests of ratepayers and utility shareholders. The COS model maximizes shareholder returns by making capital investments and increasing the rate base, which can lead to higher rates for ratepayers. In addition, this model provides no direct financial incentive to achieve state policy objectives. Finally, continued use of this model could lead to nonlinear grid defection by dissatisfied ratepayers, which would have severe repercussions for the utility and its shareholders.

The Outcomes-based PBR regulatory model is characterized as the most comprehensive PBR regime that seeks to incentivize the utility toward beneficial outcomes that can include enhanced customer experience, improved utility performance, achievement of public policy goals, and healthy financial performance. This model uses a totex approach and features an expanded set of Performance Incentive Mechanisms ("PIMs"), an Earning Sharing Mechanism ("ESM"), and a longer (5 years) regulatory period. The key conclusions for the Outcomes-based PBR model include the following:

- The *timeline* of the establishment of an Outcomes-based PBR model should take 21 months to complete to comply with State law requiring implementation of PBR by January 1, 2020, although implementation of this model in the UK took 30 months. Hawaii is expected to be able to achieve a shorter timeline than the UK due to the comparatively smaller size and lower complexity of its regulatory market. The *steps* of this timeline include the decision to design the PBR model and publishing its guiding principles and framework, determining the outputs and price control methodology and engaging with stakeholders, working with the utility companies to develop business plans that are compliant with the new model, and revising non-compliant business plans, and finally setting the price control. Alternatively, it is possible that the PUC could put in place the initial PBR framework and continue the evolution to an Outcomes-based PBR over time, although this analysis focuses on full implementation by the legislative deadline.

- The *costs* of establishing the Outcomes-based PBR model primarily consist of the operational costs of the PUC to complete the amount of work necessary to successfully implement the model. Based on an analysis of jurisdictions that have transitioned from COS to PBR and the Public Utility Commission's ("PUC's") current operating expenses, the Project Team estimates that the cost of implementing Outcomes-based PBR in Hawaii could result in a 10.9% increase in regulatory expense during the implementation period, and that the cost of operating under the PBR model would decrease to amounts similar to the current regulatory expense.

- In terms of *legal changes*, the existing legal framework, including legislation that specifically requires PBR implementation, illustrate that the PUC is authorized to implement and regulate PBR in Hawaii. No changes to the legal framework are necessary to establish the Outcomes-based PBR model.

- In terms of potential *risks*, Outcomes-based PBR carries a medium risk level for most the risk factors considered in this report (regulatory cost, regulatory complexity, rates, profit, incentives, reliability, low DER, and infrastructure inefficiency), primarily due to the uncertainty related to whether the PBR will function as intended. Aside from profits risk, the impact of these risks is generally higher for ratepayers than for shareholders.

The Conventional PBR with Light HERA regulatory model combines two regulatory models. Conventional PBR is characterized by the use of a revenue cap using an indexing formula, a three-year regulatory term, a symmetrical ESM, and slight expansion of PIMs. Light HERA is an entity that would support the PUC in the regulation and oversight of the reliability and accessibility of Hawaii's electricity systems. The key conclusions for the Conventional PBR with Light HERA model include the following:

- The *timeline* for implementing Conventional PBR should take 21 months to complete to comply with State law requiring implementation of PBR by January 1, 2020, although as a point of comparison, a comparable effort in Alberta, Canada, was implemented over the course of 33 months. Hawaii is expected to be able to achieve a shorter timeline than Alberta due to the comparatively smaller size and complexity of its regulatory market. The *steps* of this timeline include the decision to change to PBR, designing the PBR model

and publishing its guiding principles, framework, and methodology, educating and engaging with stakeholders, working with the utility companies to develop business plans that are compliant with the new model, and finally implementing the Conventional PBR. Alternatively, it is possible that the PUC could put in place the initial framework and continue the evolution to a comprehensive Conventional PBR over time, although this analysis focuses on full implementation by the legislative deadline.

The *timeline* for implementing Light HERA is not contingent upon any deadlines at this time but should take approximately two years to implement, which is the average time of a PUC docket proceeding. The *steps* involved in the PUC docket proceeding are the next steps required to implement HERA, since there is already legislation passed and initial research completed, including a statement by the PUC that the next step is an investigative proceeding.

- The *costs* of establishing Conventional PBR are, like Outcomes-based PBR, essentially the operational costs of the PUC to complete the amount of work necessary to successfully implement the model. Based on an analysis of jurisdictions that have transitioned from COS to PBR and the Public Utility Commission's ("PUC's") current operating expenses, the Project Team estimates that the cost of implementing Conventional PBR in Hawaii could result in a 10.9% increase in regulatory expense, and that the cost of operating under the PBR model would be similar to current regulatory expense.

  The *costs* of implementing and operating the HERA entity are also based on an analysis of another jurisdiction that made a similar transition to develop a HERA-like entity. Using this analysis, we estimate that the HERA transition costs are between $234,000 and $585,000, and the annual operating costs range from $483,000 to $1,208,000.

- In terms of *legal changes*, the existing legal framework, including legislation that specifically requires the implementation of PBR, as well as legislation that explicitly authorizes the creation of HERA, illustrate that the PUC is authorized to implement and regulate the Conventional PBR with Light HERA regulatory model in Hawaii. No changes to the legal framework are necessary to establish the Outcomes-based PBR model.

- In terms of potential *risks,* this model carries similar but less severe risks to Outcomes-based PBR because Conventional PBR is a less complex PBR model than Outcomes-based PBR. In addition, this model can be differentiated by the fact that it carries lower risks for reliability because it is purposed with improving reliability.

The Hybrid regulatory model is characterized by a combination of the Outcomes-based PBR model, a DSPP, and an IGO. As was described above, the Outcomes-based PBR model is the most comprehensive PBR regime that seeks to incentivize the utility toward beneficial outcomes that can include enhanced customer experience. The DSPP regulatory model alters the role of the utilities and causes the utilities to function as DSPPs. In effect, this means that the utilities as DSPPs are the purchasers and aggregator of DER and creates market tariffs and operational systems to enable behind-the-meter resources to monetize products and services. An IGO is an independent entity that manages the dispatch and planning functions on the grid and helps avoid

conflicts of interest and ensures impartiality among the parties involved. The key conclusions for the Hybrid model include the following:

- The *timeline* for the hybrid model is staggered to reduce the volatility that would probably result from too many regulatory changes at once. This staggered implementation features a January 1, 2020 implementation of an initial Outcomes-based PBR to comply with state law, implementation of the IGO in 2023, and implementation of DSPP operations beginning in 2028. The *steps* for the Outcomes-based PBR implementation are listed above. The IGO is likely to take approximately 2 years to implement, as was the case in three other jurisdictions that implemented an IGO, and the specific steps are dependent on what method the State wishes to use. The DSPP is likely to take at least 3 years to implement and will likely be conducted through a regulatory proceeding.

- The *costs* to implement the Hybrid are also a combination of the costs to implement and perform each of its component parts. As discussed above, the Outcomes-based PBR model is likely to cause a 10.9% increase in regulatory expense but should return to normal levels following the end of the three-year transition period. For both the IGO and DSPP models, the Project Team notes particular uncertainty for our cost calculations due to more limited examples from which to draw comparisons with. Nevertheless, we estimate that the IGO will be at least $8.0 million in startup costs and annual costs, based on a comparison to similar mainland organizations. The costs for implementing the DSPP are estimated at $51.4 million, spread over a three-year transition period, and a $1.0 million annual operating cost thereafter.

- In terms of *legal* changes, no changes to the legal framework are necessary to establish the Outcomes-based PBR model, as discussed above. For the DSPP model, there is no explicit authority for such an entity under state law, however, its creation should fall under the broad regulatory authority of the PUC. To err on the cautious side and to follow its own precedent of legislating specific PUC responsibilities, the State may want to legislate to explicitly authorize DSPP, although it does not need to. For the IGO model, there is no express legal authority to create an IGO. And while the PUC may be authorized to implement some aspects of it (such as opening an investigative proceeding to learn about IGOs, or using HERA to carry out some functions that the ISO would do), we expect that legislation explicitly authorizing creation of the IGO and regulation of it by the PUC would be necessary to implement this element of the Hybrid model.

- In terms of potential *risks,* this model carries similar but more severe risks to Outcomes-based PBR in terms of costs, rates, profits, and incentives because the Hybrid model combines the complex Outcomes-Based PBR with untested and complex additional entities of the DSPP and IGO. Additionally, this model is likely to improve reliability and DER penetration, but carries the risk of proving to be overly complex and expensive, possible to the extent that its objectives (like reliability) are not met.

In terms of general comparison, the Hybrid model provides the most significant overall benefit to Hawaii (see, Task 2.2.6) but is also the most complicated model to study, implement, and operate, which makes use of that model riskier than the other models in terms of operations and

finances. It is also the only model that requires additional legal changes to be made as a prerequisite to implementation. In contrast, there is more information available on the Outcomes-based PBR model and the Conventional PBR model with Light HERA, so there is less uncertainty in predicting costs and risks associated with those models.

2 Introduction, scope, and structure

2.1 Project description

DBEDT was directed by the State's legislature to Commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. The Project Team, through a competitive sealed proposals procurement,[1] was contracted to perform this study.[2]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria,[3] which include the following: achieve State energy goal; maximize consumer cost savings; enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs; and eliminate or reduce conflicts of interest in energy resource planning delivery, and regulation.[4]

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[5]

2.2 Role of this deliverable relative to others in the project

This deliverable corresponds to Tasks 2.3.1, 2.3.2, and 2.3.3 in the project scope of work. It draws from the high-level feasibility analysis in Task 2.2.3 and the top three ranked regulatory models in Tasks 2.2.6. Task 2.3.1, 2.3.2, and 2.3.3 specifically require a review of 1) the steps, timeline, and costs of establishing each regulatory model; 2) the legal changes necessary to implement each regulatory model; and 3) the financial and operational risks to ratepayers and shareholders for each regulatory model.

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[1] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[2] Hawaii Contract No. 65595 between DBEDT and LEI, signed on March 23, 2017 (hereinafter "Hawaii Contract No. 65595")

[3] H.B. 1700, Relating to the State Budget, June 24, 2016, available at: https://www.capitol.hawaii.gov/session2016/bills/HB1700_CD1_.pdf

[4] Hawaii Contract No. 6559, "Scope of Services."

[5] Hawaii Contract No. 65595, "Scope of Services."

Several of the issues discussed in this deliverable will be subject to further analysis in subsequent Tasks. With regards to the costs of the regulatory models, related tasks include:

- **Task 2.5.1 Estimated annual revenue requirement for each of the remaining regulatory models, including major costs by category; graphics comparing the three regulatory models.** The Project Team shall provide the expected annual revenue requirement for operation under each regulatory model through 2045, including the identification of all major cost elements.

- **Task 2.5.2 Assessment of system average retail rates for each regulatory model for an average residential, commercial, and industrial customer through 2045.** The Project Team shall forecast system average retail rates through 2045 using the revenue requirement from Task 2.5.1 and shall provide a comparison of forecasted retail rates for each regulatory model.

- **Task 2.5.3 Analysis of how costs differ under each regulatory model as well as an explanation of the revenue requirement calculation under each model.** The Project Team shall provide an overview of how costs vary and how the revenue requirement is calculated under each regulatory model.

With regards to the risks of the regulatory models, related tasks include:

- **Task 2.5.4 Analysis of any issues in the regulatory model that could impact the valuation of an electric utility and identify key risks to utility valuations for each regulatory model.** The Project Team shall provide an analysis of any variation to the valuation of an electric utility caused by a change in regulatory model.

With regards to the steps of the regulatory models, related tasks include:

- **Task 3.1.1 Assessing whether benefits of changes from ownership and regulatory model changes could be accomplished through changes in rate design.** The Project Team shall provide a qualitative discussion on the extent benefits of ownership and regulatory model changes, including the alignment of utility interests with State policy, can be accomplished through changes in rate design.

- **Task 3.1.2 Assessing how rate design compares to regulatory and ownership model changes considering overall market conditions.** The Project Team shall evaluate the ability of changes in rate design relative to ownership and regulatory model changes to (a) maximize consumer cost savings; (b) enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs; (c) eliminate or reduce conflicts of interest in energy resource planning, delivery and regulation; and (d) align management, ownership, and ratepayer interests.

- **Task 3.1.3 Assessing the pros and cons of managing Hawaii's electricity sector with each county operating independently as compared to a multi-county model.** The Project Team shall include an analysis of the relative advantages and disadvantages of each

county operating independently and collectively as a part of a multi-county model which may consist of the ownership of electric utilities in two or more counties. The Project Team shall evaluate the potential for each model to (1) achieve State energy goals, (2) maximize consumer cost savings, (3) enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs, and (4) eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation.

2.3 Structure of this report

This report, which responds to Task **2.3.1, 2.3.2, and 2.3.3**, discusses four primary aspects of transitions in utility regulation. The first is a listing of the **practical steps necessary** to transition from the current regulatory structure to a new structure, including an estimated timeline for the sequence and duration of these steps. The second is the **costs of such a transition**, considering both an estimate of any start-up costs related to a new regulatory model and any operating costs. The third is the **legal changes necessary** to enable a change toward the regulatory model. The fourth is an accounting and comparison of the **risks inherent in each regulatory model**.

As discussed in the Task 2.2.6 report, this report assesses the formation and risks of four models of utility regulation:

- The **Status Quo**.
- **Outcomes-based Performance-based Regulation.**
- **Conventional Performance-based Regulation** and a streamlined version of the Hawaii Electricity Reliability Administrator ("**Light HERA**").
- **Hybrid Model** [Combination of Outcomes-based Performance-based Regulation ("PBR"), Distributed System Platform Operator ("DSPP"), and Independent Grid Operator ("IGO")].

In analyzing potential transitions in utility regulatory models, the Project Team made a series of assumptions about the specific transition that would occur in the different cases, which impacts the analytical approach taken in this report:

- The **Status Quo** model. Under this model, the utilities' rates are regulated by the PUC under a traditional cost of service ("COS") regulatory model in which the utility owns both generation and wire assets, and the PUC approves electricity rates to recover the cost of providing service through those assets. In addition to COS, the PUC also has integrated some components associated with PBR including multi-year rate plan, earnings sharing mechanisms ("ESM") between the utility and the customers for the HECO companies, revenue cap, and decoupling.

  Under the status quo model, there is no transition in the utility regulatory model. Therefore, the discussions of steps, acquisition costs, and legal changes are not relevant to

this model and are not included. However, the status quo is included in the risk assessment, so that the risks of alternative models may be compared to that of the status quo. Since the eventual effects of the recent Ratepayer Protection Act (which requires a shift to a PBR regulatory model) are already separately considered in this study as a regulatory model, the status quo is represented in the risk assessment by the status quo under COS regulation.

- **Outcomes-Based Performance-based Regulation**. Under this model, regulators seek to incentivize the utility toward beneficial outcomes for society such as enhanced customer experience, improved utility performance, achievement of public policies and goals, and healthy financial performance. This model provides the utilities with the flexibility to determine their own preferred solutions and strategies to attain those desired outcomes. This model also includes expanded performance incentive mechanisms ("PIMs"), earnings sharing mechanism ("ESM"), total expenditure ("totex")[6] approach, an extended regulatory period, and more stringent reporting regimes.[7]

- **Conventional Performance-based Regulation** and a streamlined version of the Hawaii Electricity Reliability Administrator ("**Light HERA**"). In this model, the revenue requirements of the utilities are based on an indexing formula (inflation less productivity factor) for the second and third years of operation, and use of PIMs, ESM, and totex mechanisms are also included. This model also combines the use of Light HERA, which would perform the task of an ombudsman to oversee the interconnection process and reliability planning, and dispute resolution as necessary.

- **Hybrid Model** [Combination of Outcomes-Based Performance-based Regulation ("PBR"), Distributed System Platform Operator ("DSPP"), and Independent Grid Operator ("IGO")]. Under this model, an IGO would manage the dispatch and planning functions of both the transmission and distribution assets, and the utilities would serve as the DSPP to provide open access to distributed energy resources ("DER") and other providers offering energy management or customer data analytics services. Customers, service providers, DERs, and utilities would conduct transactions for energy and services on the modernized grid platform provided by utilities. An outcomes-based PBR would also be implemented to ensure utilities remain effective in their traditional functions while also performing as the DSPP.

Based on this analytical framework, the rest of this report is structured as follows:

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[6] Under a totex approach, there is no distinction between the capex and operating expenditures as the utilities are incentivized to consider the whole life costs, rather than choose between a capital expenditure or an operating expenditure solution.

[7] Task 2.1.1 (Introduction to Regulatory Models) provides more description on the mechanisms under an Outcomes-based PBR.

- **A brief discussion of the Status Quo ownership model**. This encompasses a description of the status quo regulatory model.

- **Steps, timeline, costs, and legal changes necessary for a transition to a general Performance-based Regulation model**. Although there are three regulatory models specifically considered by this study, in this section of the report the Project Team initially assesses an overarching framework for Performance-based Regulation ("PBR") including a single, defined process for the implementation and operation of PBR in general, as well as an analysis of the overarching legal framework within which the transition to PBR would occur. The Project Team uses this approach for the sake of clarity and efficiency, since each of the individual regulatory models considered by this study includes some form of PBR.

- **Differentiation between the overarching PBR analysis and the elements of the specific models considered by this study in terms of transitional steps, timeline, costs, and legal changes.** Following the analysis of the steps, timeline, costs, and legal framework needed for the implementation of PBR in general, this section will highlight and explain the differences between the elements of the different models in general, and if relevant, as they relate to the overall PBR framework. Specifically, this will include the following subsections:

    - Outcomes-based PBR
    - Conventional PBR
    - Light HERA
    - DSPP
    - IGO

  Following the analysis of the specific requirements for each element of the selected regulatory models, the Project Team will conclude with a summary of the steps, timeline, costs, and legal requirements for each of the three models (Outcomes-based PBR, Conventional PBR + Light HERA, and the Hybrid model).

- **Assessment and comparison of risks inherent in each model.** The Project Team evaluated the risks of each model in a separate section to best facilitate comparison across regulatory models within specific risk categories.

3 Status Quo Model

Hawaii's current regulatory model is a traditional cost of service ("COS") model plus some incentive mechanisms and is described in detail, below. By definition, the status quo model does not entail any steps, costs, or legal changes to implement, and thus the Project Team will not discuss those here.

Under the status quo in Hawaii, as discussed in Task 2.1.2 (Current regulatory models), vertically integrated utilities in each county (HECO, MECO, HELCO, and KIUC) continue to function as major generators in their respective counties and continue to own and operate the transmission and distribution assets in their respective service areas. Generation in the State is also provided by several Independent Power Producers ("IPPs") and customer-sited and/or owned distributed generation ("DG"). The electric utilities are regulated by the Public Utilities Commission of the State of Hawaii ("PUC"). More specifically, the PUC:

- Regulates the utilities' rates, performance, and compliance with laws and regulations;
- Reviews applications for approval to construct transmission lines, to make large capital expenditures, to issue stocks and bonds, notes and other evidence of debt;
- Oversees and monitors the electric reliability, utility's service, operations (*e.g.*, safety), and resource planning;
- Initiates and conducts investigative proceedings; provides guidelines on various standards and regulations such as interconnection standards, procurement of generation, and Performance-based regulation; implements legislative policy and develops energy policy;
- Develops and adopts administrative rules in administrative rulemaking proceedings; and
- Generally, enforces public utility laws and regulations.[89]

The State government (Legislature and Governor) establishes the energy policies, then legislative enactments and resolutions are further developed, implemented and enforced by the PUC. The Hawaii State Energy Office ("HSEO"), within the Department of Business Economic

[8] S*ee generally,* Haw. Rev. Stat. Chapter 269; *see also,* http://puc.hawaii.gov/

[9] It is worth noting that the co-op KIUC is included here in terms of rate regulation by the PUC, and this is in contrast with how cooperatives are most frequently regulated on the mainland. However, the KIUC is unregulated in other respects (such as undergoing integrated resource planning); these exemptions were described in the legal section of the co-op chapter (Task 1.3.2).

Development & Tourism ("DBEDT"), assists in developing and implementing energy policy as may be provided by the State.

Electricity rates for the electric utilities are generally determined through a COS (sometimes referred to as "rate return regulation") approach with some components associated with Performance-based regulation such as the earning sharing mechanisms ("ESM"), penalties for not achieving certain performance standards (mostly in reliability), and multi-year rate plan. Although the State has made significant progress towards achieving its statutory 100% RPS target by 2045[10] under COS regulation, the State and the PUC have identified a misalignment of incentives under the current regulatory framework for the utilities that are not necessarily conducive to making the necessary changes for continued progress.[11]

Under the traditional COS model, the PUC sets rates that allow the utilities to recover costs incurred to provide their services plus a return on investment, so long as those costs are just and reasonable. Thus, under COS, utilities' earnings are realized through a rate of return on their capital investments, thereby incentivizing utilities to increase their capital investments to increase their associated return on investment. This rate structure may result in an "infrastructure bias" for utilities to deploy capital-intense solutions. Capital intensive infrastructure projects may be incompatible with efforts to achieve state energy goals, which include increased distributed generation, increased energy efficiency, and lower sales, among other things.

Because COS rate setting is based on the utilities' costs and encourages increasing costs through expanding rate base and capital investment, there are few incentives for utilities to employ cost-saving measures, reduce electricity sales, improve energy efficiency, integrate customer-sited

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[10] Haw. Rev. Stat. § 296-92; As of 2017, Hawaii's RPS was more than 12% ahead of its statutory interim target of 15% by 2015. The 2017 RPS was 27.6%. Hawaii State Energy Office, Hawaii Energy Facts & Figures (June 2018), https://energy.hawaii.gov/wp-content/uploads/2018/06/HSEO_2018_EnergyFactsFigures.pdf at 1. See also *supra* note 15.

[11] Hawaii Session Laws, Act 005, April 24, 2018 (hereinafter "Hawaii Ratepayer Protection Act")

> "The legislature is concerned that the existing regulatory compact misaligns the interests of customers and utilities because it may result in a bias toward expending utility capital on utility-owned projects that may displace more efficient or cost-effective options, such as distributed energy resources owned by customers or projects implemented by third parties. The legislature concludes that it must ensure a change to the regulatory compact to promote decisions and strategies that will maximize public benefit, reduce ratepayer risk, and meet Hawaii's energy goals."

See also, Hawaii Public Utilities Commission, Order No. 35411 (Instituting a Proceeding to Investigate Performance-Based Regulation), Docket No. 2018-0088 (Apr. 18, 2018) at 3 (hereinafter "Order No. 35411").

> "An old regulatory paradigm built to ensure safe and reliable electricity at reasonable prices from capital-intensive electricity monopolies is now adjusting to a new era of disruptive technological advances that change the way utilities make money and what value customers expect from their own electricity company. PBR attempts to address some of the issues and disincentives inherent in traditional cost-of service regulation ("COSR")."

generation, or establish other innovative services that do not involve a large capital investment. Such innovations are fundamental to achieving the 100% RPS target. According to the Hawaii PUC, "traditional [COS] may no longer properly incent the utility to adapt to the changing landscape, to meet the challenges of a renewable and distributed energy future, or to capitalize on the opportunities inherent to this transformation. Similarly, traditional [COS] may not equip regulators with the most effective tools or mechanisms to ensure that the utility effectively adapts to these changes, challenges, and opportunities."[12]

Because of the inherent challenges that COS regulation presents in terms of moving forward with the innovations required to fully transition to 100% RPS, Governor David Ige recently signed into law the Ratepayer Protection Act.[13] The new law orders the PUC to create "performance incentives and penalty mechanisms" by January 1, 2020, that break the direct link between allowed electric utilities' revenues and investment levels. The PUC also initiated a proceeding to Investigate Performance-based Regulation on April 18, 2018.[14]

[12] Order No. 35411 at 15.

[13] *See*, Section 4.3 discussion on the future of Hawaii-specific performance-based regulation; Hawaii Ratepayer Protection Act

[14] *See,* Section 3, discussion on the Future of Hawaii-specific performance-based regulation; Order No. 35411.

4 Performance-based Regulation

Performance-based regulation ("PBR") is an approach to rate regulation that provides a wide range of mechanisms that can weaken the link between a utility's rates and its unit costs and improve efficiency. PBR is best described as a broad regulatory approach that spans a large continuum ranging from light forms of PBR to more comprehensive forms. The choice of a light versus comprehensive PBR regime is linked with the risk appetite of the utility and the regulator, the range of incentives that the regulator is willing to approve, and the demand of and feedback from interveners.[15] One reason jurisdictions shift to PBR from COS regulation is the lack of incentives under the COS to both encourage prudent and efficient capital investment and overall cost efficiency.[16] Another reason jurisdictions shift to PBR is because PBR allows the utility sufficient freedom to decide how to best optimize its resources given the targets and objectives.

Hawaii is already well positioned to shift to the PBR regulatory framework due to its current implementation of some PBR measures within its traditional COS framework,[17] the recent adoption of the Hawaii Ratepayer Protection Act,[18] and focus on PBR by the PUC.[19] Even with such existing regulations and legislation, a shift to a full PBR regulatory framework will require additional steps, costs, and legal changes to implement.

The following sections will outline the steps and timeline involved in the regulatory transition to PBR in general. This analysis also includes the estimated costs of these transitions and the overarching legal requirements and feasibility of PBR in Hawaii. An analysis of the distinctions of the steps, costs, timeline, and legal requirements between the different types of PBR models considered by this study (Outcomes-based vs. Conventional), as well as the differences between the other elements of the regulatory models, will be addressed in Section 5.

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[15] Task 2.1.1 at 29.

[16] It is worth noting that COS analysis and ratemaking principles are still important in PBR regulation. PBR regimes begin with a COS-based analysis of what the "going-in" rates should be. Moreover, COS principles including the opportunity for full cost recovery and commercially reasonable return on equity ("ROE") targets are still important tenets under PBR.

[17] Currently, Hawaii has the ESM, revenue cap, performance incentive mechanism, and flow through factors. See Task 2.1.1 at 33.

[18] Hawaii Ratepayer Protection Act. The act is currently undesignated in HRS § 269, but will be entitled "Performance incentive and penalty mechanisms." The act went into effect on July 1, 2018.

[19] Order No. 35411. The order opening an investigation on PBR is consistent with the PUC white paper, which called for the modernization of the electricity grid and regulations consistent with state energy goals. Hawaii Public Utilities Commission, Decisions and Order No. 32502 "Exhibit A: Inclinations on the Future of Hawaii's Electric Utilities," Docket No. 2012-0036, issued April 28, 2014 (hereinafter "The Inclinations").

4.1 Overall Steps and Timeline Necessary to Establish a PBR Model in Hawaii

In the transition from traditional COS to PBR, the regulatory body begins by deciding that the shift to PBR is appropriate, and then follows a series of steps over the course of some months or years to achieve the full transition. The Project Team's approach to determining the steps, the timeline for transitioning to PBR, the overarching guidelines to be used in developing the model and implementation and operation procedures, and the actual steps and timeline are detailed below.

4.1.1 Approach to Assess Overall Steps and Timeline for Transition to PBR

The shift from a traditional COS framework to a PBR framework requires a significant amount of regulatory work and involves considerable stakeholder efforts to determine the appropriate PBR mechanism and to conduct in-depth analyses of sectoral and technical issues. To determine the steps and timeline that are likely to be necessary for Hawaii to transition to PBR, the Project Team first assessed the PBR process that Hawaii is already undertaking. Then, the Project Team looked to the experiences of other jurisdictions that have already transitioned from a traditional COS regulatory model to PBR to determine general guidelines for transitioning to PBR and to assess whether the PUC's process seems reasonable by comparison.

For this evaluation, the Project Team used annual reports and other publicly available publications from the jurisdictions' regulatory bodies. The jurisdictions considered in this evaluation included the United Kingdom, Alberta Canada, and the State of New York. Based on our review of these jurisdictions, the Project Team found that the steps and timeline for implementing PBR are most clearly represented by and most similar to those undertaken in Alberta, Canada, and the Project Team used this experience as an example for comparison in this section. It should be noted that Alberta's regulatory body, the Alberta Utilities Commission ("AUC"), has implemented what this study considers "Conventional PBR." Because this report considers both Outcomes-based PBR and Conventional PBR models, the Project Team specifically notes in later sections where divergences may occur when implementing and operating an Outcomes-based PBR model as opposed to a Conventional PBR model.

4.1.2 Guidelines for Overall Steps and Timelines for Transition to PBR

The first formal step in the PBR process is when the regulator or the utility expresses an intent to implement a shift. For example, in Alberta, the Alberta Utilities Commission ("AUC") highlighted the goal of developing a regulatory framework that allows incentives for the regulated companies to improve their efficiency while ensuring that the benefits from the increase in efficiency will ultimately benefit customers.[20]

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[20] Alberta Utilities Commission. *Rate Regulation Initiative Decision 2012-237*. September 12, 2012. P. 5. Available at http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-237.pdf (Hereinafter "AUC Decision 2012-237")

Following the expression of an intent to implement PBR, regulators should assess the following principles as they determine the goals of their proposed transition to PBR:[21]

- ***Incentives compatibility:*** Ratemaking should provide appropriate incentives to both companies and customers (although there may be some natural conflict there and tradeoffs may be needed).
- ***Financial stability and fair (commercially reasonable) rate of return***: Rates must be set at a level which enables the utility to meet its statutory obligations to serve while earning a commercially reasonable return (which continues to attract investors given the business risks) and generating sufficient cash flow to support necessary investment.
- ***Administrative simplicity and transparency***: Rates should be straightforward for customers to understand; customers should be able to calculate their monthly bills themselves and be able to understand why the rate is calculated in the prescribed fashion.
- ***Cost causation and avoidance of cross-subsidies***: To achieve the most efficient patterns of consumption, economic theory states that the customers that cause a cost to be incurred should pay for that cost.
- ***Non-discrimination***: Similarly situated customers should face similar terms and conditions.

Experience and best practices dictate that the regulator should also lay down principles to guide the utilities and other stakeholders in the development and implementation process, including developing responsive and relevant PBR proposals, and the regulator in evaluating the utilities' PBR proposals.

A move to PBR may also involve hiring an economic consultant to assist in determining the PBR approach, identifying appropriate components for the PBR such as incentives and performance standards, and reviewing other available data to produce forecasts of inflation and productivity trends.

Clear and open communication between the regulator and the utilities is also an important component of the PBR transition. Regulators and stakeholders should communicate regularly so that all parties have the same level of understanding about the PBR issues. Workshops and technical conferences may be a good way to maintain understanding between these parties and solicit feedback.

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[21] For more information, see: Bonbright, Danielson and Kamerschen. 1988. Principles of Public Utility Rates, Public Utility Reports Inc, Arlington, VA; Bonbright, Danielson. 1961. Principles of Public Utility Rates, Public Utility Reports Inc, Arlington, pp. 290-94); Weston, Fredrick. 1999. "Principles of Rate Design," www.raponline.org); and Woolf, Tim and Julie Michals, 1995. "Performance-Based Ratemaking: Opportunities and Risks in a Competitive Electricity Industry," *The Electricity Journal,* Issue 8, Volume 8. October 1995.

Data availability is a critical element in the development of the PBR regime and is essential to improve the functionality of the PBR regulation over time. Because benchmarking and forecasting are such important features of PBR, it is necessary to have and collect reliable, comparable and accurate data throughout the PBR process.

Finally, as discussed in the Section 4.1.4 below, there are numerous steps involved in the PBR process and may take between 17-33 months to complete, depending on the PBR model.[22] The PBR process and timing are usually shaped by the number of utilities and interveners that participate in the regulatory process, the PBR framework the jurisdiction is using, and the regulatory generation the jurisdiction is in. Proceedings may take longer in the initial generation than in subsequent ones.[23]

4.1.3 Steps and Timeline Currently Contemplated in Hawaii

The State of Hawaii, through its legislation and a PUC docket instituting an investigation into PBR indicate that Hawaii, is now in the process of planning for a regulatory shift from COS to PBR.[24] The legislation requires the PUC to implement PBR by January 1, 2020,[25] and the PUC has already published an initial schedule of proceedings, listed below in Figure 1.[26] The proceedings are broken into two phases. Phase 1 encompasses Evaluation and Assessment, while Phase 2 involves Design and Implementation. During Phase 1, the PUC's obligations are to:

> (1) consider regulatory goals and outcomes to inform a Performance-based regulatory framework;
>
> (2) evaluate the current regulatory framework in Hawaii to examine which incentive mechanisms and regulatory components may not be functioning as intended or are no longer aligned with the public interest, and to identify specific areas of utility performance that should be targeted for improvement;

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[22] The 17-33-month timeframe is based on a previous comparison between Alberta, Ontario, Australia, and the UK. *See* London Economics International LLC ("LEI"), Literature Review: regulatory economics and performance-based ratemaking – prepared for the Dept. of Energy of Nova Scotia, May 2, 2014, at 76 (Hereinafter "LEI Literature Review").

[23] LEI Literature Review at 78-79.

[24] Hawaii Ratepayer Protection Act., Order No. 35411.

[25] Hawaii Ratepayer Protection Act.

[26] Hawaii Public Utilities Commission, Decision and Order No. 35542 ("Admitting Intervenors and Participant and Establishing a Schedule of Proceedings"), Docket No. 2018-0088, issued June 20, 2018 (Hereinafter "Order No. 35542").

(3) assess which regulatory mechanisms can best address the specific areas of interest; and

(4) identify specific performance metrics, where appropriate.[27]

After the initial decision to proceed with PBR, the PUC began holding a series of technical workshops and requiring the parties to submit briefs following the workshop as a means of providing stakeholder outreach and education and soliciting stakeholder feedback. The technical workshops should establish a common foundation from which to view the existing regulatory framework, inform the need for modifications to that framework, and focus objectives and advance the proceeding in an efficient and productive manner.[28] Following this process, the PUC plans to create a proposal that should "(1) establish a goals-outcomes foundational hierarchy; (2) summarize an evaluation of the current regulatory framework and identify a set of regulatory outcomes that warrant further focus; (3) identify which regulatory mechanisms can best achieve each outcome; and (4) identify performance metrics for those outcomes best addressed by incentive mechanisms."[29] Then, the parties will have a chance to respond to the proposal before publication of the final decision and order, which will conclude Phase 1. The procedural schedule for these steps of Phase 1 is listed in Figure 1, below.

Figure 1. Hawaii PUC Phase 1 Procedural Schedule

Procedural Milestone	Date	Corresponding Step out of overall PBR Implementation Process*
Decision to transition to PBR	April 24, 2018	Step 1
Technical Workshop #1 – Kickoff / Goals – Outcomes	July 23-24, 2018	Step 2
Goals-Outcomes Brief	August 24, 2018	Step 2
Technical Workshop #2 – Regulatory Assessment	September 27, 2018	Step 2
Regulatory Assessment Briefs (submitted by the parties)	October 25, 2018	Step 2

[27] Order No. 35542 at 39-40.

[28] *Id.*, at 42.

[29] *Id.* at 60.

Technical Workshop #3 – Metrics	November 28, 2018[30]	Step 2
Metrics Briefs (submitted by the parties)	January 4, 2019 (originally proposed for December 2018)	Step 2
Phase 1 Staff Proposal	January 2019 – proposed date	Step 3
Statement of Position	February 2019 – proposed date	Step 3
Simultaneous IRs	March 2019 – proposed date	Step 3
Reply Statements of Position	March 2019 – proposed date	Step 3
Phase 1 Decision and Order	Subsequent to Reply Statements of Position ("SOPs")	Step 4

Source: Hawaii PUC[31]

Following completion of Phase 1, the PUC will build upon the work of Phase 1 and carry out the tasks set forth for Phase 2.

During this Design and Implementation phase (Phase 2), the PUC is tasked to "continue the collaborative process to: streamline and/or refine elements of the existing regulatory framework; develop incentive mechanisms to better address specific objectives or areas of utility performance; and implement other improvements to the regulatory framework that meet the goals and outcomes established in Phase 1."[32]

Under Phase 2, these tasks are divided into three tracks including PIMs, Revenue Adjustment Mechanisms, and Other Regulatory Reforms.[33] For the PIMs track, the PUC will establish performance metrics and reporting requirements, which correspond to the development of performance targets, financial mechanisms, and performance evaluation.[34] For the revenue adjustment mechanism track, the PUC will begin development or refinement of a revenue

[30] Links to the video recordings of the July and September workshops are available here: http://puc.hawaii.gov/energy/pbr/ . The link to the slides for the November workshop is listed in the docket, posted on Dec. 11, 2018.

[31] Order No. 35542 at 57-61 contains the initially proposed schedule of proceedings. Specific dates or changes to the schedule have been updated using the Docket Documents page (dms.puc.hawaii.gov) for this docket (2018-0088). *The overall PBR process is detailed in Section 4.1.4, infra.

[32] *Id*. at 40.

[33] *Id*. at 52.

[34] *Id*. at 53-54.

adjustment mechanism.[35] And for the Other Regulatory Reforms track, the PUC will consider additional strategic changes to the regulatory framework such as non-wires alternatives and shared savings mechanisms, and new revenue opportunities.[36]

It should be noted that the detailed initial schedule of proceedings extends only through the Phase 1 Decision and Order, and that the official schedule of proceedings provides a slightly different timeline than the one originally projected in the initial order.[37] Despite the increased timeline for Phase 1 from 9 months in the initial order to 11 months in the order establishing a schedule of proceedings, and the lack of timeline for Phase 2 which could both indicate a delay in the overall timeline, it seems reasonable to assume that the PUC is still working towards the January 1, 2020 deadline.

4.1.4 Steps and Timeline Required for Transition to PBR: Alberta Example

The Project Team's assessment of the steps and timeline generally required for the transition to PBR is primarily informed by the experience of Alberta, Canada.[38] There, the transition from COS to PBR required nine steps that took approximately 33 months to complete.[39] This process and timeline are detailed below to provide an understanding of what could be anticipated for Hawaii's PBR implementation process, and to show how the PUC's implementation plan and timeline compare to a successfully completed PBR implementation.

Figure 2. Steps and Timeline to Implement PBR in Alberta

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[35] *Id.* at 55.

[36] *Id.* at 56.

[37] In Order No. 35411 Instituting a Proceeding to Investigate Performance Based Regulation at 55, the PUC expected Phase 1 to conclude in approximately 9 months, and Phase 2 to take approximately 12 months, resulting in a 21-month long process to complete the PBR, in time to meet the January 1, 2020 deadline imposed by the legislature. However, in the subsequent Order 35542 Admitting Intervenors and Participant and Establishing a Schedule of Proceedings, the schedule published is more detailed and does not adhere to the initial estimates. Instead, the schedule for phase 1 concludes after 11 months, and no detail is provided for phase 2.

[38] Alberta's transition from COS to PBR is a good example of the steps other jurisdictions (especially Hawaii due to its relatively similar size and the fact that it has already begun the process of transitioning to PBR). Additionally, Alberta was already considering PBR when the AUC was created in 2008. At the point when Hawaii created legislation and a PUC docket for PBR, it had also already been contemplating the shift (see, research involved in producing the initial order No. 35411, as well as the Inclinations in Docket No. 2012-0036, Order No. 32052).

[39] LEI Literature Review at 79.

It should be noted that for Outcomes-based PBR, which makes use of more PBR mechanisms and can be more complex overall, the Project Team anticipates the timeline could be longer than the one used in by Alberta, Canada and proposed by Hawaii. This will be explored in greater detail in Section 5.

Step	Procedural Milestone	Timeline
1.	Statement of Intent and Release of Schedule	Month 1
2.	Stakeholder Education and Outreach	Months 2 – 4
3.	Initial Publication of Guiding Principles and Stakeholder Feedback	Month 5
4.	Finalization of PBR Guiding Principles and Framework	Month 6
5.	Commencement of Independent Study	Month 7
6.	Conclusion and Results of Total Productivity[40]	Month 12
7.	Interested Parties Submit PBR Proposals	Month 19
8.	Intervention and Hearings	Months 20-33
9.	PBR Decision Issued	Month 33

Source: AUC

4.1.4.1 Step 1: Statement of Intent and Release of Schedule

In February 2010, or Month 1 of Alberta's transition to PBR, the Regulator (the AUC) announced its intent to transition from COS regulation to PBR regulation and released a preliminary schedule for the PBR implementation. The initial schedule set out an intention to apply a PBR formula for distribution rates that would begin on July 1, 2011 for a five-year term.[41] The schedule in the letter lays out a more immediate step for the implementation of PBR, including a round table discussion among utility companies and interested parties to set dates for submissions and address other issues, scheduled for March 25, 2010 (one month following the initial letter). Finally, the schedule also included that a proceeding is to be initiated by the Commission during the first PBR term to assess the PBR's success and determine adjustments or re-basing before the next PBR period.[42]

In Hawaii, the statement of intent was expressed by the Hawaii Ratepayer Protection Act, which was signed by the Governor on April 24, 2018, and requires the transition to PBR. The statement of intent was also supported by Docket 2018-0088, which was opened on April 18, 2018, by Order

[40] Total Productivity Study is generally used for PBRs with an indexation mechanism such as the "Conventional PBR" in our PBR mechanisms.

[41] Alberta Utilities Commission, Ltr to Interested Parties "Rate Regulation Initiative Round Table," at 3, February 26, 2010.

[42] *Id*. Feb. 26 2010 letter at 3.

No. 35411 to investigate PBR. Docket 2018-0088 has since become the official vehicle for designing the PBR regulatory model that is required by the Act. The initial Order described a schedule in which Phase 1 would conclude in 9 months, and Phase 2 would conclude in 12 months.[43] However, the Commission released an official Schedule of Proceedings in Order No. 35542 that provides information about both Phases but an actual schedule only for Phase 1 which takes about 11 months to complete instead of 9 months. The schedule for Phase 2 has not yet been released.[44]

4.1.4.2 Step 2: Stakeholder Education and Outreach

In Months 2-4, the AUC provided stakeholder engagement opportunities, a PBR educational and consultation workshop for stakeholders, and a short proceeding to receive input on the principles that should guide PBR development in Alberta.[45]

The first stakeholder engagement effort was the aforementioned roundtable discussion. At the roundtable discussion, all the electricity and natural gas distribution companies under the AUC's regulatory jurisdiction, as well as some other interested parties, were present. Attendees agreed both that rate regulation review could proceed separately from PBR implementation and reached consensus on three preliminary terms regarding PBR implementation. These initial terms were to (1) establish common guiding principles for implementing PBR, (2) organize a workshop to provide participants with an understanding of PBR, and (3) to extend the deadline. The Commission accepted the items of consensus that arose from the meeting and adjusted its steps and timelines as it continued forward with the PBR process.[46]

Based on the consensus reached in the Round Table Discussion to achieve a common level of understanding on the PBR implementation, the AUC engaged the Van Horne Institute to conduct a 2-day long PBR workshop with all the participants from the Round Table Discussion.[47] The AUC also set out a schedule for determining the guiding principles as agreed upon during the Round Table Discussion. In another letter, the schedule is set forth with deadlines for the submission of proposed principles by parties on June 10, 2010, and comments by parties

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[43] Order No. 35411, at 55.

[44] Order No. 35542 at 57.

[45] Alberta Utilities Commission, Letter to Interested Parties "Rate Regulation Initiative Application 1606029 ID 566: Process Steps," at 2, April 9, 2010.

[46] *Id*., Apr. 9, 2010 letter at 1-2

[47] *Id*., Apr. 9, 2010 letter at 2

respecting the submissions on June 17, 2010. The principles would be decided and published by the AUC on July 8, 2010,[48] but were actually published on July 15, 2010 in Bulletin 2010-20.[49]

In Hawaii, there are three technical workshops scheduled by the PUC as part of the PBR docket. As noted in Section 4.1.3, above, the technical workshops are intended to be collaborative and informative, and provide the parties with a common knowledge from which to assess the existing regulatory framework and to identify improvements and objectives for the PBR model. These technical workshops are similar in nature to the roundtable discussions that were held in Alberta.

4.1.4.3 Step 3: Initial Publication of Guiding Principles and Stakeholder Feedback

In Month 5, the AUC developed and released proposed guiding principles for the PBR and stakeholders provided inputs to these principles.

In Hawaii, initial guiding principles were published in the Hawaii Ratepayer Protection Act and the Order by the Commission opening the PBR docket.[50] In the Act, the guiding principles are to "directly tie an electric utility revenues to that utility's achievement on performance metrics and break the direct link between allowed revenues and investment levels"[51] and a preliminary list of performance incentives and penalty mechanisms that the Commission must consider.[52] In the Docket, the Commission notes its interest in PBR mechanisms "that result in: greater cost control and reduced rate volatility; efficient investment and allocation of resources regardless of classification as capital or operating expense; fair distribution of risks between utilities and customers; and fulfillment of State policy goals."[53] Stakeholders were able to provide feedback as intervenors in the docket process.

4.1.4.4 Step 4: Finalization of the PBR Guiding Principles and Framework

In Month 6, the AUC finalized and issued the PBR guiding principles as well as the type of PBR framework it wanted the utilities to use. The principles are listed below:

- Principle 1: A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.

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[48] Alberta Utilities Commission, Letter to Interested Parties – Rate Regulation Initiative Application No. 1606029 Proceeding ID 566, Process for Development of Guiding PBR Principles, May 14, 2010.

[49] Alberta Utilities Commission, Bulletin 2010-10, Rate Regulation Principles – PBR, July 15, 2010, available at: http://www.auc.ab.ca/News/2010/Bulletin%202010-20.pdf .

[50] Hawaii Ratepayer Protection Act; Order No. 35411, at 5.

[51] Hawaii Ratepayer Protection Act at 5.

[52] *Id*. at 5-6. "In developing performance incentive and penalty mechanisms, the public utilities commission's review of electric utility performance shall consider, but not be limited to, the following…"

[53] Order No. 35411 at 5.

- Principle 2: A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.

- Principle 3: A PBR plan should be easy to understand, implement, and administer and should reduce the regulatory burden over time.

- Principle 4: A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.

- Principle 5: Customers and the regulated companies should share the benefits of a PBR plan.

In Hawaii, the final PBR principles are still being developed through the Phase 1 process.

4.1.4.5 Step 5: Commencement of Independent Study

In Month 7, the AUC hired an independent consultant, the National Economic Research Associates, Inc. ("NERA") to conduct a total factor productivity study, or studies ("the TFP Study"). The TFP study is to determine the appropriate productivity factor to be used in the regulatory period. In our PBR options, this applies to the Conventional PBR model. The requirements of the TFP study are as follows:

a) apply to Alberta gas, and electric utilities
b) compare productivity for gas and electric utilities to economy-wide productivity;
c) make the comparison transparently;
d) use publicly available data;
e) be for use and testing in a regulatory proceeding and for adjusting rates for Alberta electric and gas utilities; and
f) be filed in AUC Proceeding 566 – Rate Regulation Initiative prior to December 31, 2010.[54]

In addition to creating the study and following the filing of the utilities PBR proposals, NERA was expected to support the TFP Study on an as-required basis determined by its counsel in any subsequent regulatory proceedings. The Commission also noted that the TFP study would be supporting evidence for a basic X-factor but did not include any estimate of a stretch factor or any other factors.[55]

In Hawaii, a TFP study might be needed for the Conventional PBR. For the Outcomes-based PBR, there is no need for a TFP study.

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[54] Alberta Utilities Commission, Letter to Interested Parties, Rate Regulation Initiative Application No. 1606029 Proceeding ID 566, Retention of Consultant to Develop a Basic X Factor, Sept. 8, 2010.

[55] *Id*. at 2.

4.1.4.6 Step 6: Conclusion and Results of Total Productivity Study

In Month 12, the independent consultant previously hired submitted its report on the total productivity study.[56]

In Hawaii, a TFP study might be needed for Conventional PBR but has not been initiated. Therefore there is no date yet as to when such a study would be concluded.

4.1.4.7 Step 7: Interested Parties Submit PBR Proposals

In Month 19, other interested parties submitted PBR proposals, and the PUC solicited statements of intention to participate.

In Hawaii, there is no date yet as to when utilities need to submit their PBR plans. However, the Act specified that PBR should be implemented starting January 1, 2020.

4.1.4.8 Step 8: Intervention and Hearings

In Months 20-33, Interveners submitted information requests and utilities submitted information responses; oral hearings; utilities submitted arguments.

In Hawaii, many third parties have already applied for and been granted intervenor status in the PBR docket. However, since there is no date yet as to when utilities need to submit their PBR plans, there is no date yet for intervention and hearings related specifically to PBR plans.

4.1.4.9 Step 9: Decision Issued

In Month 33, the AUC issued its PBR decision.

As was stated above, the deadline for the Hawaii PBR implementation is January 1, 2020, which would be Month 21 of the process.

4.1.5 Implications of the AUC timeline on Hawaii's PBR Implementation Process

When comparing the steps taken by the AUC for its PBR Implementation, it is apparent that although the actual steps are not identical, the overall process is quite similar. Both begin with a decision to transition to PBR, and to open a docket and release an implementation plan and schedule. Both continue to develop the PBR by engaging in stakeholder education and engagement (e.g., technical workshops), and used stakeholder feedback to guide the development of the regulatory framework.

Nevertheless, there are also differences between the two markets. For one, there are fewer utilities that would participate in the PBR in Hawaii (3 utilities) compared to in Alberta (6 utilities). This might mean shorter timeframe for Hawaii. Second, in Alberta, the PBR is not only for electric utilities but also for gas utilities. In Hawaii, since it's only the electric utilities that would be under

[56] *See* Alberta Utilities Commission, Letter NERA Total Factor Productivity Working Papers, Jan 21, 2011, indicating that the NERA TFP Study was released to the parties.

PBR, then the discussions would be easier and might be shorter. Finally, the AUC already had some experience handling the PBR before implementing it to the other utilities. ENMAX Power Corp. filed its PBR regime application with the Alberta Energy and Utilities Board (which later became the AUC) in 2007, and the AUC released its decision in 2009, one year before the AUC launched its initiative to reform electricity and gas utility rate regulation. This might mean that the timeline would have been longer if the AUC did not have previous experience on PBR.

Although the Hawaii PUC has not yet published the schedule of proceedings for Phase 2, it is reasonable to conclude, based on the similarities of in Phase 1 of the PUC's implementation plan to the initial steps of the AUC implementation process that Phase 2 of the PUC's plan will also be similar to the later steps in the AUC process, including a period of at least several months for the utility companies to develop and submit PBR proposals, followed by another period of several months for intervention and hearings prior to the issuance of the final PBR decision.

Another implication of the similarities between both approaches is that it seems plausible that they would have similar timelines. This is notable because the PUC is working on a 21-month timeline (beginning in April 2018, with a deadline on January 1, 2020), and the AUC completed its PBR implementation in 33 months. If Hawaii were to take around 33 months to complete its PBR implementation instead of its 21-month goal, the process would be completed at the end of 2020 or early 2021. Although it is certainly possible that the PUC will meet its original timeline, it is also important to note that the similarities between the PUC and AUC's process for implementing PBR creates some uncertainty in the Hawaii timeline.

Furthermore, if the PUC decides to implement Outcomes-based PBR instead of Conventional PBR, the Project Team anticipates that the broad steps for PBR will remain the same, but the entire process may take longer due to the greater complexity of an Outcomes-based model. The increased timeframe may also include the repetition of some steps due to the greater number of mechanisms that are used under an outcomes-based model than a conventional model. This will be elaborated on in Section 5.1.1, infra.

4.2 Transition Costs

In the scenario in which Hawaii shifts from a COS regulatory framework to a PBR framework for the regulation of electric utilities, the costs of the transition will include increases in time, expense, and use of other resources by the regulatory body to complete the steps described in the prior section and to fulfill new responsibilities set forth by the PBR framework. Transition costs can be difficult to determine because public documents often exclude specific cost allocations. However, by examining the overall costs incurred by other jurisdictions that made this transition before, the Project Team estimates costs that Hawaii can reasonably anticipate if were to pursue this regulatory option.

4.2.1 Cost Calculation Approach

As stated previously in this report, Hawaii can learn from the experiences of other jurisdictions in considering the transition from a traditional COS regulatory model to PBR. For this task, the Project Team assessed the experiences of several jurisdictions, and focused on the data from

Alberta, Canada, due to the broad similarities between PBR models, and the availability of sufficient data from which inferences could be made. The Project Team assessed the average annual costs of the AUC before, during, and after the transition from cost of service to Performance-based ratemaking. This allows for an estimate to be made both of the direct costs of transitioning from one model to the other (during the specific years in which Alberta was developing its PBR framework) as well as any long-term change in the cost of regulating utilities under the COS and PBR approaches. The Project Team then bounded this cost estimate by scaling these impacts to the average annual budget of the state of Hawaii.

4.2.2 Transition Costs in Alberta, Canada

Alberta, Canada, transitioned from COS regulation to PBR (RPI-X) only a few years after the AUC was formed. The AUC was created in 2008 as a result of the Alberta Utilities Commission Act. The Act dissolved the Energy and Utilities Board, which had previously been responsible for utility regulation into two separate entities: the AUC, which had an expanded mandate to regulate Alberta's utility sector, and the Energy Resources Conservation Board, which had jurisdiction over Alberta's oil and gas resources' development.[57] From its inception in 2008, the AUC took a Performance-based approach to its own operations and planned to implement PBR for its utilities' regulation, and began planning for PBR implementation soon thereafter, ramping up in 2010 with its announcement to interested parties that it was "beginning an initiative to reform utility rate regulation in Alberta."[58] In 2012 (fiscal year 2013) PBR was implemented,[59] with revisions made in 2013 and 2014. The initial PBR term is set to end in 2017, with the next term set for 2018-2022. The planning for the second term began in 2015-2016.

Based on the context of annual reports and other documents, the AUC's primary activities over the period from 2008-2018 consisted of initiating operations (including developing a mission statement and goals and building up staff), conducting normal regulatory business (e.g. processing rate applications, issuing decisions, managing complaints), improving efficiency in its own operations (including implementation in FY2014 of a new E-Filing System), and most notably completing the steps described in Section 4.1 to implement PBR.

As the AUC fiscal year begins in April, AUC's announcement in February 2010 to pursue PBR came near the end of its 2010 fiscal year. The 33-month timeline described above encompassed the entirety of the 2011 and 2012 fiscal years, as well as seven months of the fiscal year 2013. Based on this timeline, the Project Team considers the AUC Fiscal Years of 2011-2013 to encompass the

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[57] Alberta Utilities Commission, "100 Years of Service and Counting," http://www.auc.ab.ca/Pages/centennial.aspx .

[58] AUC Decision 2012-237 at 221.

[59] See generally, *Id*.

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transition period from COS to PBR. The 2009 and 2010 fiscal years are treated as the pre-transition period, [60] and fiscal years 2014-2018 as the post-transition period.

The AUC's inflation adjusted (in 2018 Canadian dollars) average operating expense for the pre-transition period from FY2009-2010 was roughly $33.6 million per year.[61] During the transition period from FY2011-2013, this expense increased to roughly $37.3 million, which represents a 10.9% increase over the pre-transition years' average operating expense. In the post-transition years from FY2014-2018, the average annual expense returned to roughly $33.6 million. [62]

These costs, which are summarized below in Figure 3, indicate a general annual cost increase of approximately $3.67 million CAD, or $2.78 million US,[63] over the three-year transition period.

Figure 3. Alberta PBR Transition Costs

Time Period	**Average Annual Regulatory Expense (2018 Canadian Dollars)**	**% Change from Pre-Transition Period**
Pre-Transition (FY2009-FY2010)	$33,598,102	N/A
Transition Period (FY2011-FY2013)	$37,267,590	+10.9%
Post Transition (FY2014-FY2018)	$33,645,569	+0.1%

Source: AUC, Annual Reviews for FY2009-2018[64]

[60] Fiscal year 2008 is excluded as full data is not available. The agency was established on January 1, 2008, and FY 2008 ended on March 31, 2008, resulting in a 3-month long and incomplete fiscal year.

[61] Alberta Utilities Commission, Annual Reviews for Fiscal Years 2009 – 2018, available at: http://www.auc.ab.ca/pages/annual-review.aspx . The Project Team used the information from these reports to calculate average expenses for ranges of years listed above, and we also adjusted for currency and inflation.

[62] *Id.*

[63] This analysis incorporates a currency exchange rate of 1 US Dollar to 1.32 Canadian dollars, effective on July 24, 2018.

[64] Alberta Utilities Commission, Annual Reviews for Fiscal Years 2009 – 2018, available at: http://www.auc.ab.ca/pages/annual-review.aspx . The Project Team used the information from these reports to calculate average expenses for ranges of years listed above, and we also adjusted for currency and inflation.

4.2.3 Estimate of Transition Costs of PBR in Hawaii

In Hawaii, the Commission is responsible for regulating all public utilities, including the electric utilities that serve the islands, as discussed earlier. Over the past five years, the costs of PUC's regulatory activities have been somewhat stable, with average annual direct PUC expenditures of $6.3 million (inflation-adjusted to 2018 dollars).

Like Alberta, Hawaii is embarking on a multi-year process of transitioning towards PBR. The Project Team anticipates these efforts to require a broadly similar timeline. While the timelines laid out by the Hawaii legislature (18 months)[65] and PUC (21 months)[66] are somewhat shorter than the 33-month schedule experienced by Alberta, based on stakeholder conversations conducted as part of this task, the Project Team considers it reasonable to expect that some planning activities may extend beyond this initial 18 to 21-month period. Therefore, the Project Team considers the three-year transition period identified in the above analysis of AUC's annual costs to be a useful guide.

Scaling the transition costs experienced by AUC to Hawaii has a degree of inherent uncertainty, as the overall annual expense of AUC is roughly four times greater than that of the Hawaii PUC ($25.5 million US per year in Alberta compared to $6.3 million US in Hawaii).[67] It is expected that the PBR transition costs experienced by AUC and the PUC will scale somewhat with size, due both to the larger overall size of Alberta compared to Hawaii and the larger number of affected utilities. However, it is also reasonable to expect that some costs may be fixed and similar in nature between the two jurisdictions. Therefore, the Project Team provides two estimates for annual cost impacts in Hawaii, one based on the overall cost increase experience by AUC in the three-year transition period, and one based on the percentage change in costs. As noted in Figure 4 below, this approach yields an effective range in the estimated cost impact of between $683,000 and $2.78 million (in 2018 dollars) per year over a three-year transition period (for a total transition cost of between and $2.0 million and $8.3 million). This is equivalent to a 10.9% increase in the PUC's annual average expenses in the period from 2013 to 2017.

Based on the experience of AUC to date, the Project Team does not project a long-term change in regulatory costs beyond this transition period.

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[65] SB2939, or 2018 Act 005, The Hawaii Ratepayer Protection Act, went into effect on July 1, 2018, and requires PBR implementation by January 1, 2020.

[66] The PBR docket 2018-0088, Order No. 35411, states that the PUC anticipates Phase 1 to take 9 months to complete and Phase 2 (Design and Implementation) to take 12 months. Thus, the total time anticipated by the PUC in its initial order to implement PBR is 21 months. At 55.

[67] Hawaii Public Utilities Commission, Annual Reports for Fiscal Years 2013-2017, available at: http://puc.hawaii.gov/reports/annual-reports/; Alberta Utilities Commission, Annual Reviews for Fiscal Years 2009 – 2018, available at: http://www.auc.ab.ca/pages/annual-review.aspx. The Project Team used the information from Hawaii PUC reports to determine the average expense for the range of years listed above, adjusted for inflation. We also used the calculations cited in footnotes 60 and 62, supra, to determine the percentage rate of increase due to PBR transition.

Figure 4. Anticipated Hawaii PBR Costs

Cost Type		Cost (2018 Dollars)
Average Annual HI PUC Expense (2013-2017)		$6,252,965
Expected Annual PBR Transition Cost in Three-Year Period	Low Estimate (Based on AUC Percent Change)	$682,931
	High Estimate (Based on AUC Dollar Change)	$2,779,915

Source: PUC and AUC[68]

4.2.4 Unique Cost Factors for Achieving Conventional PBR in Hawaii

Unique cost factors for achieving PBR in Hawaii may include the following:

4.2.4.1 Existing Legislation

As will be discussed in the following section,[69] Hawaii recently adopted legislation that essentially requires the shift from COS to PBR by changing the requirements for what the PUC considered "just and reasonable."[70] Additionally, the PUC recently opened a docket to investigate PBR and appears to have already made some progress in their research.[71] Therefore, it seems reasonable to conclude that many of the initial costs of PBR implementation are already being incurred.

4.2.4.2 KIUC Exemption from PBR Legislation

KIUC is not included in Hawaii's new PBR legislation and will continue to regulate rates under a COS model.[72] Although this represents a unique situation, it should be noted that KIUC represents electricity generation and distribution for approximately 5% of the State of Hawaii's population, whereas the HECO companies provide electricity to the other 95% of the population. Although it was not possible to separate PUC expenses on KIUC regulatory activities from the

[68] *Id.*

[69] Legal Considerations, infra at 4.3.

[70] Hawaii Ratepayer Protection Act: "The purpose of this Act is to protect consumers by proactively ensuring that the existing utility business and regulatory model will be updated for the twenty-first century by requiring that electric utility rates be considered just and reasonable only if the rates are derived from a performance-based model for determining utility revenues."

[71] Order No. 35411, Instituting a Proceeding to Investigate Performance-Based Regulation, April 18, 2018.

[72] Order No. 35411, Instituting a Proceeding to Investigate Performance-Based Regulation, April 18, 2018, at 9-10.

PUC financial data set, the effect of the aggregate data from the PUC on our cost estimates is likely to be relatively insignificant due to the small size of KIUC.

4.2.5 Conclusions for Anticipated Transition Costs of PBR in Hawaii

We base our expectations of PBR transition costs in Hawaii on the comparable experience of Alberta. The AUC undertook a transition process to implement PBR as detailed in the steps listed in Section 4.1.4, supra, during FY 2011-2013. During the transition period, costs increased by 10.9%, and then returned to pre-transition levels after the transition period concluded. This indicates that PBR incurs significant costs during the initial transition period, but not in its normal operations after its successful implementation. Notably, in Alberta after implementation of the initial PBR term, the AUC operated under PBR and began planning the second PBR period during 2015-2016 and still maintained the costs that were comparable to pre-transition (rather than transition) period costs.[73]

As previously discussed, the Alberta example is representative of the regulatory shift from COS to PBR and may be used as a general guide for such transitions. In addition, it is a good point of comparison for Hawaii due to its relatively similar size, and because the AUC was already considering PBR at its inception, so its financial data may more closely reflect the situation of Hawaii, which already has begun the process of PBR planning.

Using these general guidelines as determined from the Alberta example, the Project Team determined that the transition costs in Hawaii will be roughly 10.9% higher than their costs in the pre- or post-transition periods. Again, the Project Team notes that it is possible these costs may be larger if the PUC ultimately uses a more complex PBR model.

4.3 Overarching Legal Analysis for Implementation of Performance-based Regulation

The legal analysis for implementing a new regulatory model, including PBR and any variation the Commission may ultimately choose, should be based on the following general legal analysis of the regulation of public utilities in Hawaii. Specific caveats for each specific regulatory model considered by this study will be included in the relevant subsequent sections that provides details on each specific model.

4.3.1 Existing Legal Framework of the Hawaii Public Utilities Commission

This section details the existing legal framework for the regulation of public utilities in Hawaii, including the federal, state, and local laws that provide the Commission with regulatory authority, and the nature and extent of the PUC's regulatory authority. Due to the apparent nature of this legal framework, this section will focus primarily on the relevant state laws and prior instances of the PUC's exercise of such authority. This section concludes that the existing framework grants the PUC broad power to regulate the state's electric utilities, such as by

[73] See AUC annual report and financial data, FY 2016.

implementing PBR.[74] The application of this broad authority to each regulatory model will be detailed in the respective sections in the report. However, the Project Team notes that this authority does not expressly include the ability to create a new entity like an IGO. This specific situation will be detailed in Section 5.4.5.

4.3.2 Federal Law

The Federal Energy Regulatory Commission ("FERC") is the federal agency within the US Department of Energy that is responsible for regulating the interstate transmission of electricity, natural gas, and oil, and the sale of electric energy at wholesale in interstate commerce.[75] FERC also reviews proposals to build liquid natural gas terminals and interstate pipelines, conducts licensing in and inspection of private, municipal and state hydroelectric projects, ensures the reliability of the high voltage interstate transmission system, monitors and investigates energy markets, and oversees environmental matters related to natural gas and hydroelectric projects and major energy policy initiatives.[76]

Hawaii is not subject to FERC jurisdiction to regulate electricity transmission or wholesale sales because such transmission and sales do not constitute interstate commerce,[77] which is the basis for FERC's jurisdiction.[78] Hawaii is an island chain, whose own grid system consists of separate grids for each island within the state.[79] In contrast, in the continental US grids span across

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[74] Regulation of KIUC is less certain. Currently, the PUC has authority to regulate them, but state law provides that electric cooperatives such as KIUC may apply for exemption from PUC regulation. *See* Haw. Rev. Stat. § 269-31.

[75] 16 U.S.C. § 824(b)(1).

[76] FERC, "What FERC Does," https://www.ferc.gov/about/ferc-does.asp.

It is worth noting regulation of *retail* electricity and natural gas sales to customers, *inter alia*, is considered outside of FERC's jurisdiction. *Id,* emphasis added.

[77] Under the 10th Amendment of the U.S. Constitution, States are granted police power to protect the public welfare, health and safety. *See* "The powers not delegated to the United States by the Constitution, or prohibited by it to the States, are reserved to the States respectively, or to the people." U.S.C. Const. Amend. X.

[78] "The provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce…. The Commission [FERC] shall have jurisdiction over all facilities for such transmission or sale of electric energy, *but shall not have jurisdiction*, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used in the generation of electric energy or over facilities used in local distribution or only *for the transmission of electric energy in intrastate commerce*, or over facilities for the transmission of electric energy consumed wholly by the transmitter." 16 U.S.C. § 824(b)(1), emphasis added.

[79] Hawaiian Electric Company, Inc., "Power Facts – Power Supply," (last visited Aug. 21, 2018), https://www.hawaiianelectric.com/about-us/power-facts/power-supply .

multiple states, allowing for electricity generated in one state to be transmitted and sold in other states.[80]

The North American Reliability Corporation ("NERC") is a nonprofit organization that was granted the designation of the Electric Reliability Organization authorized and required by the Energy Policy Act of 2005.[81] Notably, upon receiving this designation, NERC filed mandatory Reliability Standards with FERC and Canadian authorities, 83 of which were approved by FERC in March 2007 and are legally enforceable.[82] As the name of the organization suggests, NERC's reliability requirements apply to the North American bulk power system.[83] Hawaii is also not subject to the jurisdiction and authority of NERC due to its geographic location and exclusion from the North American bulk power system.[84]

4.3.3 State Law

The State of Hawaii, to the extent that it is not preempted by federal law, is governed by the Hawaii State Constitution, the Hawaii Revised Statutes ("HRS") and the Hawaii Administrative Rules ("HAR"). Specifically, the PUC is responsible under state law for the regulation of public utilities, including electric utilities like the HECO companies. Furthermore, the state's authority to regulate the public utilities preempts the counties' efforts to do the same, although county governments may still participate in proceedings before the PUC.[85]

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[80] United States Dept. of Energy, United States Electricity Industry Primer (July 2015), available at https://www.energy.gov/sites/prod/files/2015/12/f28/united-states-electricity-industry-primer.pdf at 11.

[81] Energy Policy Act of 2005, Pub. L. 109-58 (Aug. 8, 2005), available at https://www.ferc.gov/enforcement/enforce-res/EPAct2005.pdf; NERC, Reliability Legislation (last visited Aug. 21, 2018), available at https://www.nerc.com/AboutNERC/keyplayers/Pages/Reliability-Legislation.aspx .

[82] *See e.g.*, *Summary of Reliability Legislation (Source: Section 1211 of H.R. 6, the "Energy Policy Act of 2005"),* NERC, (Aug. 8, 2005), available at https://www.nerc.com/AboutNERC/keyplayers/Documents/Summary_of_Reliability_Legislation-20050808.pdf

[83] NERC, "About NERC," NERC (last visited Aug. 21, 2018), https://www.nerc.com/AboutNERC/Pages/default.aspx

[84] The North America bulk power system includes the continental US and Canada. *See* NERC, "Key Players" (last visited Aug. 21, 2018), https://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx).

[85] *See, e.g.*, Hawaii Public Utilities Commission, Order Granting Intervention, Docket No. 2008-0273, issued November 28, 2008 (Order grants the City and County of Honolulu intervenor status in a proceeding to investigate the implementation of feed-in tariffs).

4.3.3.1 Legal Authority of the PUC

The PUC is a state agency that is authorized and structured by Chapter 269 of the Hawaii Revised Statutes, which is entitled "Public Utilities Commission."[86] This HRS chapter provides the general powers and duties of the PUC,[87] lists all relevant definitions,[88] and provides detail on the PUC's authority to engage in specific conduct including ratemaking[89] and initiating investigations of public utilities or other relevant issues.[90] The Hawaii Revised Statutes are also where legislative actions are codified. In the context of the PUC, this has included many measures, such as the State's 100% RPS goal,[91] the development of a Community-Based Renewable Energy tariffs by the utilities with required review by the PUC,[92] and most recently, the Hawaii Ratepayer Protection Act.[93] For procedural guidance, the PUC is also governed by HRS chapter 91 on Administrative Rulemaking for all state agencies,[94] as well chapter 6-61 in the Hawaii Administrative Rules that provides the rules of practice and procedure for PUC proceedings.[95]

4.3.3.1.1 The General Powers and Duties of the Public Utilities Commission.

The general powers and duties of the Public Utilities Commission are as follows:

> *The public utilities commission shall have the general supervision hereinafter set forth over all public utilities,[96] and shall perform the duties and exercise the powers imposed or conferred upon it by this chapter. Included among the general powers of the commission is*

[86] Haw. Rev. Stat. § 269-1 et seq.

[87] Haw. Rev. Stat. § 269-6

[88] Haw. Rev. Stat. § 269-1

[89] Haw. Rev. Stat. § 269-16

[90] Haw. Rev. Stat. § 269-7

[91] Haw. Rev. Stat. § 269-92

[92] Haw. Rev. Stat. § 269-27.4

[93] Hawaii Ratepayer Protection Act. The act is currently undesignated in HRS § 269, but will be entitled "Performance incentive and penalty mechanisms." The act went into effect on July 1, 2018

[94] Haw. Rev. Stat. § 91 et seq.

[95] Haw. Admin. R. 6-61-1 et seq.

[96] Public utilities are defined to include electric utilities like the HECO companies and KIUC, but not to include renewable energy systems like IPPs or individual systems located on a customer's property. *See* Haw. Rev. Stat. § 269-1.

the authority to adopt rules pursuant to chapter 91 necessary for the purpose of this chapter.[97]

In addition to that general purpose, the Commission is also required to consider other regulatory impacts in the context of achieving the State's energy goals. These required considerations include the need to reduce the States' reliance on fossil fuels via energy efficiency and increased renewable energy generation, the costs and benefits of a diverse fossil fuel portfolio and maximizing the energy efficiency of all electric utility assets to lower and stabilize electricity costs, and whether implementation of a shared cost savings incentive mechanism, a renewable energy curtailment mitigation incentive mechanism, a stranded cost recovery mechanism, or differentiated authorized rates of return on common equity would be in the public interest.[98]

The power and duty to have general supervision over all public utilities is extremely broad and enables the PUC to justify nearly any action it takes, so long as a driving purpose behind that action is the protection of the public interest. The public interest refers to a balance of various interests affecting the public whom the Commission serves. This includes "long-term versus short-term needs, affordable rates versus efficient price signals, environmental values versus global competitiveness."[99]

Additionally, the term "public interest" in statutory language often creates a presumption that the Commission must also protect the public from the private interests of the utilities that may be at odds with the public at large, or the ratepayers. In short, protecting the public interest means assuring "universal, reliable, and safe service at reasonable rates."[100]

4.3.3.1.2 Definition of Public Utilities.

Under this statutory framework, public utilities are defined as including any entity "who may own, control, operate, or manage…any plant or equipment, or any part thereof… for the production, conveyance, transmission, delivery, or furnishing of light, power, heat, cold, water, gas, or oil."[101]

In short, the electric utilities in Hawaii, the HECO Companies and KIUC, meet this definition and are considered public utilities for the purposes of the statute. Notably, this definition explicitly

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[97] Haw. Rev. Stat. § 269-6

[98] *Id.*

[99] Scott Hempling, Regulating Public Utility Performance: The Law of Market Structure, Pricing and Jurisdiction (American Bar Ass'n, 2013) at 3.

[100] *Id.*

[101] Haw. Rev. Stat.§ 269-1(1)

excludes those who own, control, operate or manage a renewable energy system on their own property, as well as those who sell energy generated on their own property to an electric utility.[102]

4.3.3.1.3 Regulation of Utility Rates; Ratemaking Procedure.

The PUC is specifically tasked and authorized to regulate the rates and ratemaking procedures for public utilities by HRS § 269-16. This notably includes ratemaking for electric utilities. Specifically, and in relevant part:

> *All rates, fares, charges, classifications, schedules, rates, rules, and practices made, charged, or observed by any public utility … shall be just and reasonable and shall be filed with the public utilities commission…. The commission, in its discretion and for good causes shown, may allow any rate, fare, charge, classification, schedule, rule, or practice to be established, abandoned modified, or departed upon notice less than that provided for in section 269-12(b).*[103]

From the statute, it is clear that the PUC has broad power and discretion within the parameters of what is "just and reasonable" to regulate public utility rates and ratemaking processes. This is particularly relevant to the issue at hand regarding the regulatory capacity of the PUC, because the statute explicitly grants the Commission the authority to make any such changes.

4.3.3.1.4 Investigative Power

The PUC is vested with investigative power by HRS § 269-7, which states in relevant part, that the Commission and each Commissioner "shall have the power to examine into the condition of each public utility… the fares and rates charged by it … [and] its classifications, rules, regulations, practices, and service, and *all matters of every nature affecting the relations and transactions between it* and the public or persons or corporations."[104] Further, "*any investigation may be made by the commission on its own motion*, and shall [also] be made when requested by a public utility to be investigated, or by any person upon a sworn written complaint to the commission."[105]

This investigative power is a powerful tool that is used frequently by the Commission to look into various regulatory matters on its own accord, although often times the Commission will cite a legislative action or concern as an additional reason for the investigation.

4.3.3.1.5 Enforcement Power

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[102] Haw. Rev. Stat. § 269-1(2)(M), (N).

[103] Haw. Rev. Stat. § 267-16(a), (b), emphasis added.

[104] Haw. Rev. Stat § 269-7(a), emphasis added.

[105] Haw. Rev. Stat § 269-7(c), emphasis added.

The PUC is also authorized by HRS § 269-15 to institute proceedings to enforce HRS Chapter 269. If the PUC believes that a public utility or person is "violating or neglecting to comply with any provision of this chapter or of any rule, regulation, order, or other requirement of the commission" it shall notify the utility or person who is in violation, and may begin proceedings as necessary to require the correction of the deficiency(s), and may also issue citations, as necessary.[106]

The power to enforce the existing rules and regulations of the PUC allows the PUC to more effectively carry out its own duties and obligations under the statute.

4.3.3.1.6 General Procedure

The Rules of Practice and Procedure Before the Public Utilities Commission are part of the Hawaii Administrative Rules ("HAR"), Chapter 61. These rules complement the HRS statutes and provide specific rules and guidelines for PUC practice and procedure to "secure the just, speedy, and inexpensive determination of every proceeding."[107] Examples of these rules include general provisions and requirements for proceedings before the Commission, agency hearing procedures, those for intervention and participation,[108] rate increase applications and tariff changes,[109] and Commission investigations, among others.[110]

The PUC also adheres to the rules outlined in HRS Chapter 91 on Administrative Procedure, which include the procedure and guidelines for rulemaking by agencies such as the PUC, and for contested case hearings.[111]

4.3.3.1.7 Select Codified Legislative Initiatives

The legislature can amend existing duties or add new responsibilities to the PUC.[112] Recently, the legislature has added additional requirements for the PUC to meet that further the state's energy and climate change mitigation and adaptation goals, including directives to change the regulatory process. Several are detailed herein.

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[106] Haw. Rev. Stat. § 269-15(a).

[107] Haw. Admin. R. § 6-61-1 (current through 2018).

[108] Haw. Admin. R. § 6-61-55 through § 6-61-57 (current through 2018).

[109] Haw. Admin. R. § 6-61-85 through § 6-61-94 (current through 2018).

[110] *See generally,* Haw. Admin. R. chapter 61.

[111] See generally, Haw. Rev. Stat. § 91.

[112] Haw. Const., Art. III

4.3.3.1.7.1 State Renewable Energy Target

HRS § 269-92, Renewable Portfolio Standards, became law in 2015 and states that "each electric utility company that sells electricity for consumption in the State shall establish a renewable portfolio standard of: … one hundred percent of its net electricity sales by December 31, 2045."[113] Additionally, the PUC may "establish standards for each utility that prescribe what portion of the renewable portfolio standards shall be met by specific types of renewable energy resources,"[114] and can also monitor the utility companies' compliance with these standards, and impose penalties on delinquent utility companies following a hearing in accordance with HRS chapter 91.[115] In the case of situations that are beyond the electric utility company's reasonable control, including, for example, natural disasters or labor strikes, the Commission may use its discretion to waive penalties in part or in whole.[116]

The purpose of this statute is to:

> *update and extend Hawaii's clean energy initiative and renewable portfolio standards to ensure maximum long-term benefit to Hawaii's economy by setting a goal of one hundred percent renewable by 2045; provided that extending the [RPS] goals and transition to energy independence beyond 2030 shall be undertaken in a manner that benefits Hawaii's economy and all electric customers, maintains customer affordability, and does not induce renewable energy developers to artificially increase the price of renewable energy in Hawaii. This target will ensure that Hawaii moves beyond its dependence on imported fuels and continues to grow a local renewable energy industry*.[117]

This statute sets an overarching policy of reducing Hawaii's dependence on imported fossil fuel and growing the local renewable energy industry. It also provides clear goals and tasks for the PUC to follow (i.e., establishing standards and enforcing the law) as the PUC fulfils the obligations of this statute in particular, and as the PUC applies the statute to other regulatory actions. Indeed, the PUC has used this law as a basis for many of its actions since its passage, including most recently, its investigation of Performance-based regulation (detailed, *supra*), and in its interactions and requirements of the public utilities via rate-making procedures.

4.3.3.1.7.2 Community-Based Renewable Energy Tariff

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[113] Haw. Rev. Stat. § 269-92(a).

[114] Haw. Rev. Stat. § 269-92(b).

[115] Haw. Rev. Stat. § 269-92(c).

[116] Haw. Rev. Stat. § 269-92(d).

[117] Hawaii Session Laws, Act 097, June 8, 2015 (H.B. 623 CD1, Relating to Renewable Standards), available at https://www.capitol.hawaii.gov/session2015/bills/HB623_CD1_.pdf.

HRS § 269-27.4, Community-based renewable energy ("CBRE") tariffs, became law in 2015 and requires each electric utility to file a proposed CBRE tariff or tariffs with the PUC by October 1, 2015. The PUC in turn and pursuant to HRS § 269-16, shall establish a CBRE tariff or tariffs, provided that such tariff(s) are found to be in the public interest.[118] CBRE tariffs are required to be approved by the Commission and must be tariff(s) that:

> *(1) Allow an electric utility customer to participate in an eligible renewable energy project that is providing electricity and electric grid services to the electric utility;*
> *(2) Allows the electric utility to implement a billing arrangement to compensate those customers for the electricity and electric grid services provided to the electric utility;*
> *(3) Is designed to provide fair compensation for electricity, electric grid services, and other benefits provided to or by the electric utility, participating ratepayers, and nonparticipating ratepayers; and*
> *(4) To the extent possible, standardizes and streamlines the related interconnection processes for community-based renewable energy projects.*[119]

In drafting the law, the legislature found that "it is in the public interest to promote broader participation in self-generation by Hawaii residents and businesses through the development of CBRE facilities in which participants are entitled to generate electricity and receive credit for that electricity on their bill. The legislature also found that CBRE stimulates the economy, reduces GHG emissions, promotes energy independence, and helps the state to meet its clean energy goals. Thus, the purpose of this law, as stated in the Act, is "to make the benefits of renewable energy generation more accessible to a greater number of Hawaii residents," and provides that the CBRE tariff "should, to the extent possible, be designed in an open and accessible process that should accommodate a variety of community based renewable energy projects, models and sizes."[120]

The PUC began this work in Docket 2015-0389, which is still open at the time of this writing.

4.3.3.1.7.3 Grid Modernization

HRS § 269-145.5, a statute on Advanced grid modernization technology and principles, came into effect in its current iteration on June 20, 2014 and requires the Commission to "consider the value of improving electrical generation, transmission, and distribution systems and infrastructure within the State through use of advanced grid modernization technology in order to improve the

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[118] Haw. Rev. Stat. § 269-27.4(a). The PUC's establishment of a CBRE tariff(s) can be based on a review of the proposed tariffs submitted by the utility companies. The PUC then may approve/establish that tariff as a CBRE tariff.

[119] Haw. Rev. Stat. 269-27.4

[120] Hawaii Session Laws, Act 100, June 10, 2015 (S.B. 1050 CD1, Relating to Energy (CBRE Tariffs)), available at https://www.capitol.hawaii.gov/session2015/bills/GM1200_.PDF.

overall reliability and operational efficiency of the Hawaii electric system."[121] The legislature also instructs the PUC to advance the public interest by balancing various considerations that are associated with such modernization of the electric grid. This includes enabling a diverse portfolio of renewable energy resources, expanding options for customers to manage their energy use, maximizing interconnection of distributed generation at just and reasonable rates while maintaining grid reliability, determining fair compensation for electric grid services to customers, and maintaining or enhancing grid reliability.[122] One of the purposes of the law was to accommodate increased DER and levels of renewable energy on the grid that would result from the efforts to comply with HCEI and to achieve RPS goals (although at this time, the goal was not yet at the level of 100% by 2045). Since the adoption of this law, the PUC has worked on several grid modernization projects, including those in Docket Nos. 2016-0087 and 2017-0226.

4.3.3.1.7.4 Performance-based Regulation (PBR)

The Hawaii Ratepayer Protection Act ("Act") was set forth by the Hawaii State Legislature in the 2018 session, was signed into law by Governor David Ige on April 24, 2018 as Act 005, and took effect on July 1, 2018.[123] The Act will be incorporated into the Hawaii Revised Statutes ("HRS") under Chapter 269, although official classification is pending.[124] The purpose of the act is "to protect consumers by proactively ensuring that the existing utility business and regulatory model will be updated for the twenty-first century by requiring that electric utility rates be considered just and reasonable only if the rates are derived from a Performance-based model for determining utility revenues."[125]

The Act requires the PUC to "establish performance incentives and penalty mechanisms that directly tie electric utility revenues to that utility's achievement on performance metrics and break the direct link between allowed revenues and investment levels. The performance incentives and penalty mechanisms, as may be amended by the public utilities Commission from time to time, shall apply to the regulation of electric utility rates under section 269-16" by January

[121] Haw. Rev. Stat. § 269-145.5(a).

[122] Haw. Rev. Stat. § 269-145.5(b).

[123] Hawaii Ratepayer Protection Act

[124] 2018 Legislative Session Undesignated Enactments, § 269 -. Performance incentive and penalty mechanisms. Eff. July 1, 2018

[125] Hawaii Ratepayer Protection Act, at 4.

1, 2020.[126] The Act also provides a list of regulatory impacts the PUC should consider in its design of such mechanisms.[127]

Shortly before this Act was signed into law, the PUC on its own initiative opened an investigative proceeding (as it is authorized to do under HRS § 269-7) to investigate PBR. Although it seems quite clear that the PUC was aware that the bill was moving through the legislature during this time, it highlights that the PUC had the authority to begin its investigation. Although it seems common for the PUC to start a new initiative once it has gathered public support or reasonably anticipates a mandate from the legislature, it is clear from the PUC's powers to regulate rates and the ratemaking procedure under 269-16 that the PUC does have the power to initiate such proceedings on its own. Most of the proposed regulatory models in this study are completely within the purview of the PUC to investigate, determine which will be most beneficial to the public interest, and implement. The exception to this general statement is the ISO model, which will be discussed in Section 5.4.5.

4.3.4 Independent Initiatives of the PUC: The Inclinations

The Inclinations are a white paper written by the Commission and included as an attachment to the decision and order to reject the HECO Companies Integrated Resource Plan ("IRP") proposal in 2014.[128] The Commission notes its authority to review and approve or reject the IRP according to HRS § 269-6(a) and to carry out investigations of the public utilities according to HRS § 269-7(a) and (c). Due to the Commission's decision that the HECO Companies "failed to articulate a sustainable business model in the intervening time since this directive [request for IRP] was set forth by the Commission almost one year [prior] in Order No. 31288,"[129] the Commission authored the white paper to set forth its perspective on the various business strategies and regulatory policy changes required to align the HECO companies' business model with customer interests and state policy goals.[130] Specifically, these include sections on Creating a 21st Century

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[126] Hawaii Ratepayer Protection Act, at 5. Note that HRS § 269-16 is the primary statutory authority / mandate for the PUC to regulate utility rates and engage in ratemaking procedures, and sets forth the "just and reasonable" standard that the PUC must apply in its regulatory activities.

"All rates, fares, charges, classifications, schedules, rules and practices made, charged, or observed by any public utility or by two or more public utilities jointly shall be just and reasonable and shall be filed with the public utilities commission." HRS § 269-16(a).

[127] Hawaii Ratepayer Protection Act, at 5-6

[128] The Inclinations at 1.

[129] *Id.*

[130] *Id.*

Generation System, Create Modern Transmission and Distribution Grids, and enact Policy and Regulatory Reforms to Achieve Hawaii's Clean Energy Future.[131]

The inclinations are significant because they provide an example of the Commission acting without instruction from the legislature or any other institution. Although the paper does not ultimately set forth any legal requirements, it was used by the Commission in the recent months and years following its publication as a guideline that informed many of the Commission's activities and directives to the electric utilities.[132]

4.3.5 Legal considerations necessary for a transition to PBR

In the scenario in which Hawaii shifts from a COS regulatory framework to a PBR framework for the regulation of electric utilities, it is important to consider both the existing legal framework and whether any regulatory or legislative changes are required to implement the PBR regulatory model.

4.3.5.1 PUC Dockets Initiating and Regulating PIMs

The PUC has considered implementing various PIMs and even PBR prior to its most recent interest in PBR.[133] This section will discuss some of these PUC dockets, noting, in particular, the legal authority the PUC cites as enabling their actions, and whether the PUC initiated the docket independently, in response to external events, or out of obligation.

4.3.5.1.1 Docket 99-0396, Application of HECO companies for approval to implement PBR in their next respective rate cases.

In 1999, the HECO Companies filed an application to implement PBR in their next rate cases to the Commission under HRS sections 269-7 and 269-16. The HECO Companies proposed the use of an index-based price cap, an earnings sharing mechanism, and service quality mechanisms (SAIDI, SAIFI, percentage of call center calls during business hours answered within 30 seconds, and overall satisfaction in customer surveys with customers with recent transactions). The Commission did not approve this request, noting that COS regulation "has long been deemed

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[131] *Id.* at 3.

[132] See e.g., the Hawaii Ratepayer Protection Act. Additionally, other orders citing the inclinations include In the Matter of Hawaiian Electric Company, Sept. 29, 2015 (the Inclinations as part of the consideration for transmission planning in regards to an application for approval to commit funds for a generating station project, at 33); as considerations in power purchase approvals (e.g., In the Matter of Hawaiian Electric Company, Inc., Docket No. 2014-0308, Decision & Order No. 33076); as consideration in the order instituting a proceeding to investigate integrated grid planning (in the matter of Public Utilities Commission, Docket No. 2018-0165, Order NO. 35569); as consideration when reviewing Power Supply Improvement Plans (e.g., In the Matter of Public Utilities Commission Instituting a Proceeding to Review the Power Supply Improvement Plans for [the HECO Companies], Docket No. 2014-0183, Order No. 34696.)

[133] This interest includes the new Hawaii Ratepayer Protection Law, the PUC's investigation into PBR, and the commission of this study.

essential because the public utility industries were thought to be a natural monopoly."[134] Although the Commission declined to change from COS to PBR at that time, it explicitly did not preclude applicants from filing another PBR proposal in the future.[135] This docket and order represent an example of the PUC exercising its investigative and rate-making procedure authority to make a decision. This docket was brought by the HECO Companies and does not respond to nor satisfy any legislative mandate.

4.3.5.1.2 Docket 2008-0274, Investigation to Implement a Decoupling Mechanism

This docket was opened as an investigative proceeding to examine implementing a decoupling mechanism for the HECO Companies in 2008. The PUC was able to open this investigative document because of its authority to investigate under HRS 269-7. The investigation was brought in response to an Agreement between the State, Consumer Advocate, the Department of Commerce and Consumer Affairs, and the HECO companies to accelerate clean energy as a result of the creation of the Hawaii Clean Energy Initiative ("HCEI") – which is a partnership that began in 2008 between the State of Hawaii and the US Department of Energy.[136] In the final Decision and Order in this Docket, the PUC approved the decoupling mechanisms proposed (a Revenue Balancing Account ("RBA") and a Revenue Adjustment Mechanism ("RAM")) in the Joint Final Statement of Position by the HECO Companies and the Consumer Advocate, subject to some modifications. The mechanisms agreed to were intended to be consistent with the mechanism agreed to in the HCEI agreement.

In this situation, the PUC again used its investigative and regulatory authority to open the docket and perform its regulatory duties. This particular docket was opened as a direct result of an external state action – the creation of the HCEI.

4.3.5.1.3 Docket 2013-0141 Investigation to Reexamine the Existing Decoupling Mechanisms

This investigative docket to reexamine existing decoupling mechanisms (as approved in Docket No. 2008-0274) was implemented in 2013 and is still open as of August 2018. In the initial Order 31289, filed on May 31, 2013, "Instigating an Investigation to reexamine the Existing Decoupling Mechanisms," the Commission notes that its own concerns regarding the decoupling mechanisms "echo those expressed by the 2013 Hawaii State Legislature in connection with Senate Bill 120," which authorized the Commission to "establish a policy to implement economic incentives and cost recover regulatory mechanisms, as necessary and appropriate, to induce and accelerate electric utilities' cost reduction efforts, encourage greater utilization of renewable energy, accelerate the retirement of utility fossil fuel generation, and increase investments to

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[134] Hawaii Public Utilities Commission, Order No. 18353, Docket No. 99-0396, issued Feb. 2, 2001

[135] *Id.* at 5-6.

[136] *See* Hawaii Public Utilities Commission, Final Decision and Order, Docket 2008-0274 issued Aug. 31, 2010, at 3.

modernize the State's electrical grids."[137] The Commission concluded that in light of that legislative guidance, and alongside its own concerns, it would examine whether potential economic incentives could be used to achieve reduced costs and improved customer rates and service.[138]

In Decision and Order 31908, the Commission ordered that in addition to revising the decoupling mechanisms, the HECO Companies would also be required to post tracking metrics online (reliability measures, generation availability, clean energy metrics and the cost of final delivered energy to customers by rate class).[139] This docket was not created in response to any request by the HECO Companies or to a legislative act. Rather, the Commission on its own accord initiated this investigation to examine whether the HECO Companies' decoupling measures from the Decision and Order in Docket 2008-0274 "effectively served their intended purposes, are fair to the HECO companies and the HECO companies' ratepayers, and are in the public interest."[140] The orders include as a guideline that "rates and charges of regulated public utilities in Hawaii must be reasonable, *and the commission has broad powers to investigate and examine the rates and practices of public utilities subject to its jurisdiction,*" citing for example of this authority, HRS sections 269-6, 269-7, and 269-16.[141]

In a later Order No. 32735 filed March 31, 2015, the Commission directed the HECO companies to make changes to their existing decoupling mechanisms[142] and considered whether the RAM was appropriate, whether PBR or other PIMs should be implemented, and whether specific measures to establish cost controls for baseline capital projects should be implemented.[143] Ultimately, this order established a cap on annual RAM adjustments and distinguished between PBR framework proposals and stand-alone PIMs without implementing either. Instead, the PUC provided a procedural schedule and directed the HECO companies to propose conventional standalone PIMs and identify appropriate steps for ECAC adjustments.[144] This order also referred again to Senate Bill 120 from the 2013 state legislature as legislative guidance for its consideration of performance metrics. Despite the existence of such legislative guidance, it seems that this was

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[137] Hawaii Public Utilities Commission, Order No. 31289, Docket No. 2013-0141, issued May 31, 2013, at 18-19.

[138] *Id*. at 20.

[139] Hawaii Public Utilities Commission, Decision and Order No. 31908, Docket No. 2013-0141, issued Feb. 7, 2014, at 70-77.

[140] Order No. 31908 at 2.

[141] Order No. 31908 at 9.

[142]Hawaii Public Utilities Commission, Order No. 32735, Docket No. 2013-0141, issued March 31, 2015, at 2.

[143] *Id.* at 15-16.

[144]*Id.* at 38.

a supporting reason for the regulatory review rather than a primary one because it is included again as "guidance," rather than as part of the background information that set the context for this particular order.[145]

In Order 34514 of this docket, filed on April 27, 2017, the PUC established several backstop service quality PIMs (SAIDI, SAIFI, call center performance metrics), established guidelines for Major Project Interim Recovery, and directed the HECO companies to file tariff sheets for the established PIMs and revised RBA with an effective date of January 1, 2018.[146] This order also briefly references the same 2013 bill as referenced above, again as "legislative guidance."[147] Most recently, in order 35165 of this docket, the PUC directed the HECO companies to adopt the PIMs and RBA tariffs.[148]

4.3.5.1.4 Additional Proceedings Related to PIMs

In addition to the above detailed PIM dockets and resulting orders, the Commission has held (and in some cases, is still in the process of) other proceedings related to other PIMs or initiatives to increase renewable energy generation or update the grid to accommodate more renewable energy. These include proceedings on grid modernization,[149] procurement of utility-scale renewable energy generation,[150] and various other measures embedded in the utilities planning processes such as general rate cases and PSIP proceedings.[151]

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[145] *Id.*

[146] Hawaii Public Utilities Commission, Order No. 34514, Docket No. 2013-0141, issued April 27, 2017.

[147] *Id*. at 14.

[148] Hawaii Public Utilities Commission, Order No. 35165, Docket No. 2013-0141, issued December 29, 2017.

[149] Docket No. 2016-0087, Order No. 34436, Application for Approval to commit funds in excess of $2,500,000 for the Smart Grid Foundation Project; Docket No. 2017-0226, Order No. 34773, Instituting a proceeding related to the HECO Companies' Grid Modernization Strategy (which adds to Docket No. 2016-0087).

[150] Docket No. 2017-0352, Order No. 35405, Establishing a Performance Incentive Mechanism for Procurement in Phase 1 of the [HECO] Companies' Final Variable Requests for Proposals.

[151] Note: Other dockets for further consideration (excluded in discussion above for brevity) include:
Grid Modernization: Docket No. 2016-0087, Order No. 34436 (Mar. 9, 2017), Application for Approval to commit funds in excess of $2,500,000 for the Smart Grid Foundation Project; Docket No. 2017-0226, opening docket Order No. 34773. Instituting a proceeding related to the HECO Companies' Grid Modernization Strategy (follows up to 2016-0087, opens a repository.
MPR – 3 yr. fixed cycle for general rate cases – no docket number
ECAC amendment possible in ongoing HECO general rate case. Docket no. 2016-0328, order no. 35372 filed Mar. 29, 2018 at 8.
HECO companies PSIP – Docket No. 2014-0183
PPAC purchased power adjustment clause see HRS 269-16.22

4.3.6 Conclusions on the Existing Legal Framework

Based on the information detailed above, it is clear that the PUC has wide-ranging and strong statutory authority to engage in the supervision and guidance of the states' electric utilities. Included in this authority is the power to investigate the utilities for any matter regarding its purpose to balance the interests of the companies and the customers. Additionally, the Commission has broad power to engage in ratemaking and ratemaking procedure regulations and oversight. The legislature may also add powers or responsibilities to the PUC and has done so. Examples of this include the legislature's addition of the 100% RPS requirement by 2045, the requirement to create a Community-Based Renewable Energy program, the requirement to create a grid modification plan, and most recently, the requirement to change the regulatory framework from COS to PBR, all of which fall to the PUC to implement. These newer laws provide the PUC with additional authority to regulate in specific ways or on specific topics.

In addition to the inclusion of this authority in the plain language of the statutes, the PUC's legal authority is expressed repeatedly through the Commission's regular activities in regulating the electric utilities. This report has detailed examples of the Commission acting both in response to external factors, such as a legislative mandate or applications of the utility companies, and several examples of the Commission acting independently of any other source. These examples are the reexamination of the decoupling mechanisms in Order 31908, where the Commission noticed the mechanisms were having an undesirable effect and acted upon it, and the *Commission's Inclinations*, which were written in response to the Commission's observation that the HECO Companies were not making the necessary plans to align with the state's energy goals. Notably, these inclinations were aligned with state energy goals.

4.4 Gaps in Existing Legal Framework and Required Changes

In terms of the PUC's authority or ability to enact any of the proposed regulatory changes examined in this report, it seems clear from the above discussion that the PUC has the authority to act as it sees fit to further its objectives within ratemaking and planning activities,[152] which include pursuing actions which accomplish state energy goals. In examples where the PUC initiated a regulatory proceeding or published a policy paper, it was because of the PUC's statutory authority, and also because the PUC observed a misalignment between the utilities' proposal(s) and the goals of the state or the public interest. In other instances, the PUC acted out of responsibility to fulfill a state statute or legislative act.

The proposed regulatory changes all involve some form of Performance-based regulation. The purpose of PBR is to disconnect the utilities' revenue from its cost of service and create incentives for the utility to undertake any number of initiatives which usually consist of increased renewable energy, modernized grids, and increased energy efficiency. Because PBR generally aligns the interests of the utility and the consumer, and often results in the overall modernization of the grid and increased generation and use of renewable energy, it seems clear that any PBR would be

[152] Note that this authority does not extend to creating new state agencies or other entities that may aid in achieving state energy goals, such as an IGO. This legal distinction is discussed in Section 5.4.5, infra.

aligned with pre-existing state energy goals and would be within the public interest. Therefore, PBR is something the PUC is authorized to consider or initiate in its regulatory capacity.

Despite the above conclusion, consideration of whether the PUC is able to act on its own to implement PBR is not necessary here because the State has already enacted a law requiring it. Therefore, in the same way that the PUC is working to implement other state laws that further state energy goals (such as the 100% RPS by 2045 target), it is required to do the same for PBR.

4.5 Conclusions on Overarching Legal Considerations for PBR

The Hawaii PUC has broad authority to regulate the public utilities in Hawaii and is specifically *required* to implement PBR. Due to this authority and legislative mandate, the PUC must implement some form of PBR that helps the state achieve its energy goals and is in the public interest.

Legal analyses for HERA and other elements of the Hybrid model will be considered in the relevant sections, below.

5 Distinctions Between Elements of the Proposed Regulatory Models

5.1 Outcomes-based PBR v. Conventional PBR

Although the previous sections provided an overarching assessment of the steps, timeline, costs, and legal requirements for PBR implementation, the models considered by this study differentiate between an Outcomes-based PBR model and a Conventional PBR model. This section of the report seeks to distinguish where differences in the costs, timeline, and legal requirements lie between both models.

5.1.1 Outcomes-based PBR

As discussed in previous working papers and Task 2.2.6 of this study, Outcomes-Based PBR is the most comprehensive PBR regime. It seeks to incentivize the utility toward beneficial outcomes for society. These potential outcomes include (i) enhance customer experience, (ii) improve utility performance, (iii) achieve public policies and goals, and (iv) healthy financial performance. Under this PBR regime, utilities have flexibility on preferred solutions and strategies to attain those outcomes. Other mechanisms such expanded performance incentive mechanisms ("PIMs"), earnings sharing mechanism ("ESM"), total expenditure ("totex") approach, and more stringent reporting regimes are included under the Outcomes-based PBR. The steps for implementing Outcomes-based PBR generally follow the overall steps that are used for PBR in general, or for Conventional PBR. However, due to the more intensive nature of Outcomes-based PBR, the Project Team anticipates that a switch to an Outcomes-based PBR model will involve more regulatory work, the repetition of some steps due to the inclusion of more program elements, and an overall longer timeline.

5.1.1.1 Overview of the Steps, Timeline, and Costs used to Implement the Outcomes-based PBR model

To determine the specific steps, timeline, and costs that Hawaii should anticipate as part of the implementation process for an Outcomes-based PBR model, the Project Team looked to the experience of the UK's transition to the RIIO model (Revenue = Incentives + Innovation + Outputs) for guidance. Such awareness of the potential or likely steps, timeline and costs may be particularly useful for Hawaii because of the differences in the timeline that was experienced in the UK and the timeline that is expected for Hawaii.

5.1.1.1.1 Steps and Timeline Currently Contemplated in Hawaii

If Hawaii were to implement an Outcomes-based PBR model, the PUC would still be required to meet the legislative deadline for PBR implementation by January 1, 2020. As discussed in Section 4.1.3 above, the PUC's current plan and schedule of proceedings appear to be aligned with this deadline, although it doesn't specify a particular PBR model for implementation.

In contrast, the implementation of the RIIO process in the UK took 30 months, which is significantly longer than the 21-month timeline currently contemplated in Hawaii. This timeline varied depending on the iteration (first iterations require more planning) and whether the utility

companies were on the "fast-track" or not.[153] This 30-month timeline for RIIO does not include the 19 months used by the UK's regulatory agency Ofgem to decide to change regulatory models and to develop the original design for RIIO, and the Project Team does not anticipate that Hawaii would have to replicate that lengthy design process. However, we also cannot assume some preliminary design time would not be necessary and note that such design time could cause some delay if it were actually needed.

It should also be noted that the timeline of the PBR implementation could be shorter than the timeline used in the UK because Hawaii uses far fewer utility companies than the UK does. Additionally, the Outcomes-based PBR timeline would depend on the mechanisms that the PUC decides to include in the first regulatory term. The greater the quantity and complexity of PBR mechanisms it wants to include, the longer the process would take. However, the Project Team does not expect a "fast track" mechanism to shorten the timeline required for implementing Outcomes-based PBR in Hawaii because use of such a mechanism is not feasible in Hawaii at this time.[154] The indicative timeline discussed in this memo applies to the Outcomes-based PBR that the Project Team proposed. The specific steps, timeline, and costs of the UK's transition to RIIO are detailed below for consideration and comparison with Hawaii's proposed plan.

5.1.1.1.2 Steps and Timeline Required for Transition to Outcomes-based PBR: UK's RIIO Example

The UK's regulatory agency, Ofgem, announced the decision to review its existing regulatory framework (Conventional PBR using an RPI-X formula) in March 2008. After some effort with research and development, in October 2010 Ofgem announced its intention to implement RIIO to regulate its electric and gas utilities. The first RIIO regulatory period began in 2013.

Following the decision to implement the RIIO model, the UK's development and implementation of the actual RIIO plans required a timeline of approximately 30 months (or 2.5 years). The steps taken during the course of these 30 months was grouped by Ofgem into four "stages," which are detailed in Figure 5, below:

Figure 5. Steps and Timeline to Implement RIIO in the UK

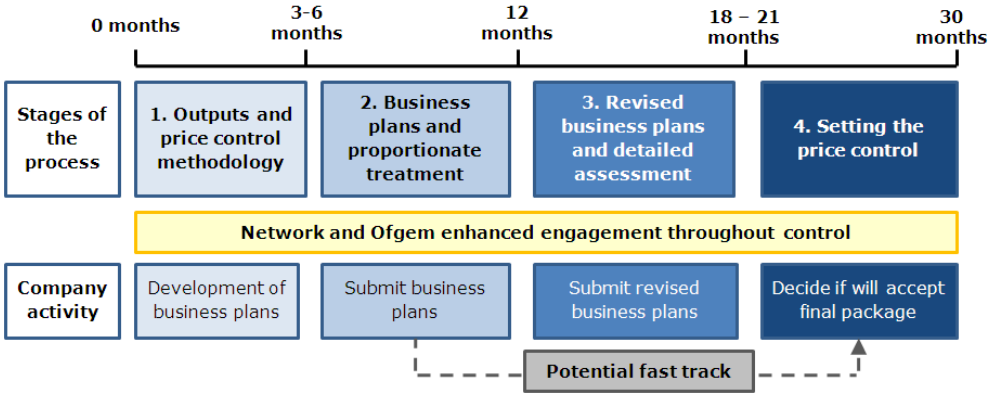
Stage	Task	Months
1.	Determine outputs and price control methodology; Stakeholder engagement	0 through 3-6
2.	Business Plan Development and Assessment	3-6 through 12

[153] Fast-track in RIIO discussed in Section 5.1.1.1.2, below.

[154] Fast-track is not feasible in Hawaii at this time because the process defined by the legislature and the PUC currently only contemplates a single process for PBR implementation, rather than multiple processes to be implemented in various situations. Changes to the PUC implementation process or new legislation requiring such changes could create an option for a fast track, but until that happens the Project Team finds that a Fast Track mechanism would not be used.

3.	Revise Business Plans and Detailed Assessment	12 through 18-21
4.	Set the Price Control	18-21 through 30

Figure 6. Ofgem diagram of RIIO implementation process



Source: Ofgem[155]

Although these four steps appear to be quite different from the 9 steps used in Alberta, the substance that comprises both sets of steps are broadly similar. Both begin with a decision to change the regulatory framework and continue to conduct research and analysis to determine the goals, methods, and outputs for the model and include robust stakeholder engagement during this process. Both then work with the utilities to develop plans for operating under PBR, arrive at a final decision, and continue to review and revise the model over time.

There are also key distinctions between the UK's Outcomes-based PBR implementation process and the implementation process for Conventional PBR. Outcomes-based PBR is a more complex scheme of regulatory mechanisms to be researched, designed, and implemented. Additionally, the RIIO model includes optimal business planning (according to the other desired outputs) as an incentive mechanism itself and provides a "fast track" for utility companies that comply with those outputs. More specifically, fast-tracked companies are those that submit business plans that meet various requirements, and consequently become eligible to quickly finalize all elements of their price control settlement with Ofgem, including drafting license changes. In contrast, companies that are not fast-tracked must spend additional time working with Ofgem to revise their business plans and go through additional detailed assessments and further scrutiny. Following the conclusion of their revision process, the non-fast-tracked companies are then able to finalize their price controls, although the additional review and revision processes can be time-consuming.[156]

[155] Ofgem, Handbook for Implementing the RIIO model, October 4, 2010 at 57.

[156] *Id.* at 10-11.

In Hawaii, the fast track that is used in the RIIO model would not be an option because the process issued by the PUC is singular and would not permit fast-tracking.[157] However, the issue of achieving Outcomes-based PBR in Hawaii in 21 months rather than a longer time period like the 33 months used in the UK could be addressed in other ways. The PUC might be able to complete the process within the relatively limited amount of time permitted by choosing PBR mechanisms that are not too complex and consequently would not require additional studies (e.g., productivity studies, etc.), and by taking care to work as efficiently as possible. The fact that the Hawaii market is significantly smaller with fewer utilities than the UK's could also result in the process requiring less time for completion. Therefore, while the PUC should be aware of the possibility of delay due to the complexity of the Outcomes-based PBR model and the length of time it took to implement RIIO in the UK, the PUC's target timeline appears to be feasible for implementation of Outcomes-based PBR if the process can be expedited as a result of the smaller market size, simpler mechanisms, and diligent and efficient work.

5.1.1.2 Transition Costs for Outcomes-based PBR

Due to the similarity between the overall regulatory work that must be done in a transition to a Outcomes-Based and Conventional PBR model, the Project Team determines that the cost estimates drawn from the conventional AUC example above are broadly appropriate for an Outcomes-Based model as well, though costs may be slightly higher for an Outcomes-Based model depending on the actual quantity and complexity of regulatory mechanisms being implemented.

5.1.1.3 Legal Requirements for Outcomes-based PBR

Based on the PUC's broad statutory authority to engage in the supervision, guidance, and regulation of Hawaii's public utilities according to the public interest and to further the State's energy goals, as well as its explicit authority via recent legislation to implement PBR detailed in Section 4.3, above, it is clear that the PUC is authorized to implement PBR as it sees fit, including an Outcomes-based PBR model. Thus, there are no gaps in the legal framework to enable to PUC to enforce and regulate under an Outcomes-based PBR framework.

5.1.2 Conventional PBR

Conventional PBR is characterized by the use of a revenue cap using an indexing formula (e.g., inflation less productivity factor), a 3-year regulatory term, a totex approach, a symmetrical ESM, and continuing use of the performance incentive mechanisms already in place under the current PBR-Light / Cost of Service ("COS") regulatory regime as well as a slight expansion of them. These PIMs include those that regulate the availability and reliability of service, cost control, service quality, customer engagement, competitive procurement, and renewable portfolio standard ("RPS").

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[157] Even if the PUC's schedule and plan could accommodate the fast track, the Project Team notes concern about whether it is even reasonable to expedite this process during the first generation of the PBR, since parties will need time to determine how the model works, how to work within it, etc.

In comparison with the Outcomes-based PBR model, Conventional PBR is based on inputs rather than outputs. Conventional PBR's revenue requirements or rates are increased by an indexation formula, which is the inflation less productivity factor. Utilities using Conventional PBR must provide their review requirements and justification for the costs in determining their rates. Other key features of Conventional PBR in relation to Outcomes-based PBR include the use of a shorter regulatory period (3 years instead of 5), a condensed list of PIMs, and fewer overall regulatory requirements.

5.1.2.1 Overview of the Steps, Timeline, and Cost used to Implement the Conventional PBR model

The steps, timeline, and cost to implement the Conventional PBR model can be represented by the example of Alberta's transition from COS to RPI-X. This analysis was included in Section 4.1, above. In sum, the Project Team concluded that in Alberta, Conventional PBR required approximately 33 months to implement, using a series of nine steps that encompassed the initial planning and research, shareholder engagement, additional studies, submission of PBR proposals by the utility companies and subsequent review, and finally implementation through the issuance of a decision. In its analysis of the steps and timeline used by the AUC to implement the Conventional PBR model, the Project Team noted that PUC would not necessarily follow the same steps as Alberta's in implementing the PBR. However, the Project Team also noted that awareness of this discrepancy may help the PUC in designing and implementing an efficient process that completes all the steps in a more efficient manner and within the 21-month timeline.

5.1.2.2 Transition Costs for Conventional PBR

The transition costs for Conventional PBR are also represented in the example of Alberta's transition from COS to RPI-X, included in Section 4.2, above. In summary, the Project Team's calculations show that operating expenses increased by approximately 10.9% during the transition phase to Conventional PBR and that costs decreased to pre-transition levels following the transition.

5.1.2.3 Legal Requirements for Conventional PBR

The PUC is authorized to implement PBR as it sees fit, including a Conventional PBR model. This is based on the PUC's broad statutory authority to engage in the supervision, guidance, and regulation of Hawaii's public utilities according to the public interest and to further the State's energy goals, as well as its explicit authority via recent legislation to implement PBR detailed in section 4.3, above. Thus, there are no gaps in the legal framework to enable to PUC to implement and regulate under a Conventional PBR framework.

5.1.3 Summary of Distinctions Between Outcomes-Based and Conventional PBR

Based on the analyses included in Sections 4.1, 4.2, 4.3, and 5.1, above, it is clear that Outcomes-based PBR is more robust and complex than Conventional PBR, but despite that difference, the general steps to implement either PBR model are quite similar, as are the baseline costs.

In comparison with Conventional PBR, Outcomes-based PBR requires a longer period of research and design and potentially can require more extended time periods during which to engage with

the utility companies in developing PBR compliant business plans. Both models utilize periods of research and design, stakeholder engagement, and subsequent design modification, require the issuance of a final PBR model (which includes the various PBR mechanisms), engagement with stakeholders and the utility companies to operate under the chosen PBR model, and continued review and revision. The Project Team anticipates the financial impact on the PUC of implementing either PBR model will be an increase in operating expenses by about 10.9% during the transition, and a return to ordinary expense amounts following implementation. The Project Team also notes that Outcomes-based PBR could also render a higher cost due to the greater number of and complexity of PBR mechanisms within the model. Finally, the PUC is legally authorized to implement either PBR model.

5.2 Light HERA

The Hawaii Electricity Reliability Authority ("HERA") was envisioned by the 2012 Hawaii State Legislature as an entity that would support the Commission in the regulation and oversight of the reliability and accessibility of Hawaii's electricity systems. The legislature viewed reliability oversight and regulation as necessary to ensure that all types of generation resources (and especially renewable energy sources) could be integrated into the grid without compromising reliability.[158] Specifically, the purpose of HERA's enabling act was to:

> *[A]uthorize the public utilities commission to perform necessary electric system reliability and grid access oversight functions, and to allow the commission to contract for the services of a Hawaii electricity reliability administrator to support the commission in carrying out those critical functions throughout the state.*[159]

5.2.1 Statutory Definition and Authority of HERA

The 2012 Hawaii Legislative Act 166 regarding the reliability of the Hawaii electric system is codified in the Hawaii Revised Statutes ("HRS") under chapter 269, section 141 et seq. Under these statutes, the PUC has jurisdiction over matters concerning interconnection requirements and interconnections within the state.[160] This includes the authority to:

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[158] Hawaii Session Laws, Act 166, June 27, 2012 (S.B. 2787 CD1, Relating to Electricity), available at: https://www.capitol.hawaii.gov/session2012/bills/SB2787_CD1_.htm .

[159] *Id.*

[160] Haw. Rev. Stat. § 269-142(c). The Hawaii electric system is defined as "all electric elements located within the State together with all interconnections located within the state that collectively provide for the generation, transmission, distribution, storage, regulation, or physical control of electricity over a geographic area; provided that this term shall not include any electric element operating without any interconnection to any other electric element located within the state." Haw. Rev. Stat. § 269-141

- adopt, by rule or order, reliability standards and interconnection requirements that would apply to any electric utility and any user, owner, or operator of the Hawaii electric system;[161]

- monitor the reliability and operation of the Hawaii electric system using any data necessary to ensure the reliable operation of the Hawaii electric system, and to compel the production of any such data;[162]

- take all necessary steps (including the imposition of reasonable penalties and adoption of rules) to ensure that any electric utility or other entity that uses or connects to the Hawaii electric system complies with all adopted reliability standards and interconnection requirements;[163] and

- make determinations regarding any disputes related to interconnection.[164] The PUC is also required to consider the value of modernizing the grid while balancing a variety of public interests.[165]

With specific regard to HERA, the statute provides that

> *the commission may contract for the performance of its functions under this part with a person, business, or organization, except for a public utility as defined under this chapter, that will serve as the Hawaii electricity reliability administrator … provided that the commission shall not contract for the performance of its functions under 269-142(a) and (b) [to adopt by rule or order, or develop as necessary or by recommendation, reliability standards and interconnection requirements] and 269-146 [to create a Hawaii electric reliability surcharge].*[166]

In other words, under this law, the PUC may contract with a qualified third party to delegate these duties, but still retains full authority over HERA and retains the exclusive authority to adopt or develop reliability standards and interconnection requirements.[167] In addition, the entity selected to serve as HERA shall satisfy whatever qualifications are established by the Commission by rule or order, and maintain reasonable and necessary staffing to offer "prudent and reasonable

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[161] Haw. Rev. Stat. § 269-142(a).

[162] Haw. Rev. Stat. § 269-143.

[163] Haw. Rev. Stat. § 269-144.

[164] Haw. Rev. Stat. § 269-145.

[165] Haw. Rev. Stat. § 269-145.5.

[166] Haw. Rev. Stat. § 269-147(a).

[167] Haw. Rev. Stat. § 269-147(b).

recommendations on the development of reliability standards and interconnection requirements," to provide adequate technical ability to properly monitor operations of the Hawaii electric system, and to possess an appropriate level of impartiality for reviewing matters concerning interconnection.[168]

As discussed in the previous working papers, the statute also provides a funding mechanism for HERA operations. Under section 269-146, the PUC "may require, by rule or order, that all utilities, persons, business, or entities connecting to the Hawaii electric system… shall pay a surcharge that shall be collected by Hawaii's electric utilities... Amounts collected through the Hawaii electricity reliability surcharge shall be transferred in whole or in part to any entity contracted by the Commission to act as [HERA]," and these funds shall be used "for the purposes of ensuring the reliable operation of the Hawaii electric system and overseeing grid access on the Hawaii electric system through the activities of HERA."[169]

These funds are to be used only to carry out the operations of HERA, which include "administrative, technical, or other related requirements for effectively ensuring the reliability of the Hawaii electric system,"[170] and will not be available to satisfy any other current or past obligations of the State.[171] Additionally, HERA will be responsible for submitting a status and financial report to the PUC each year following the date of initial contracting.[172]

5.2.2 Current Status of HERA

While having legislative authority to create HERA, the PUC has not yet done so and is not required to.[173] From the available record, it appears that the PUC was in the process of considering reliability standards for the electric utilities prior to the enactment of the HERA law. In response to a 2009 decision and order approving a Feed-in Tariff ("FIT"), in which the Commission found that "reliability constraints exist and could affect the amount, type, and location of renewable energy that can be incorporated into the HECO Companies' systems without compromising

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[168] Haw. Rev. Stat. § 269-148.

[169] Haw. Rev. Stat. § 269-146.

[170] Haw. Rev. Stat. § 269-149.

[171] *Id*.

[172] *Id*.

[173] Note that according to the HERA statute, "the commission *may* develop reliability standards and interconnection requirements as it determines is necessary or upon recommendation from any entity, including an entity contracted by the commission to serve as the Hawaii electric reliability administrator under this part." HRS § 269-142, emphasis added. Note also, "the commission *may* contract for the performance of its functions under this part with a person, business, or organization… that will serve as the Hawaii electricity reliability administrator provided for under this part…"HRS § 269-147, emphasis added.

reliability,"[174] the Commission opened another docket on September 8, 2011 to "Institut[e] a Proceeding to Investigate the Implementation of Reliability Standards for [the HECO Companies]."[175] As a result of this docket, a Reliability Standards Working Group ("RSWG") was created and conducted collaborative work over a period of 19 months.[176] The primary purpose of the RSWG was to "recommend an appropriate set of reliability standards, metrics, rules, and criteria to 'help determine how [to] interconnect the maximum amount of renewable generation to the grid while preserving grid reliability,' consistent with Hawaii's clean energy statutory mandates and policies."[177] The RSWG's final report was filed with the PUC on October 18, 2012, with reliability standards recommendations for the PUC to consider for adoption.[178] In addition to providing detailed information and recommendations for reliability standards for PUC consideration, the RSWG also provided insight on its perception of the role of HERA. Specifically, the RSWG listed that HERA:

a. *Shall monitor the "day-to-day" standards activities, including proposing specific standards, and implementation, administration and enforcement policies and procedures*
b. *Shall oversee the activities of the Standards Development Board/Committee and/or sub-committees*
c. *Shall establish the eligibility criteria for membership on the Standards Development Board/Committee*
d. *Shall select and/or remove members from the Board/Committee*
e. *Shall have an employee(s) or representative(s) on the Board/Committee*
f. *Shall prepare implementation policies and procedures, including, but not limited to, administration, enforcement, compliance oversight, and establishment of penalties and assessment thereof for review and approval by the PUC*
g. *Shall implement and enforce all approved standards, policies and procedures*[179]

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[174] Hawaii Public Utilities Commission, Decision and Order, Docket No. 2008-0273, issued Sept. 25 2009, at 49.

[175] Hawaii Public Utilities Commission, Order Opening Docket, Docket No. 2011-0206, issued Sept. 8, 2011.

[176] Note: the members of the RSWG consisted of many of the frequent parties to other electric utility-related dockets, such as the utilities (HECO, HELCO, MECO, and KIUC), state counties, state agencies (DCCA, DCA, DBEDT), Generators and advocates, and environmental advocates. Hawaii Public Utilities Commission, Order No. 30694 (RSWG Final Report), Docket No. 2011-0206, issued Oct. 18, 2012, at 5 (hereinafter "RSWG Final Report").

[177] RSWG Final Report at 220 (RSDG Appendix D-1 – Potential Framework for Development and Implementation of Electric Utility Reliability Standards in Hawaii).

[178] RSWG Final Report at 101.

[179] *Id.* at 225. Notably, the Standards Development Board/Committee is responsible for the identification, review, and approval of standards for drafting. Id.

Additionally, the RSWG proposed that HERA would consider and adopt the various reliability standards that were developed in the final report, and then submit the standard or other information to the PUC for approval.[180]

The RSWG also proposed the creation of a Registered Ballot Body who would be registered with HERA and vote on reliability standards, a Ballot Pool comprised of members of the Registered Ballot Body who would respond to pre-ballot requests to participate in a particular standard action, and a Standards Board/Committee who would serve at the direction of HERA to manage the standards processes for development of reliability standards and associated information in accordance with the information and procedures laid out in the RSWG's final report.[181] The RSWG also noted that HERA could form technical committees, subcommittees, working groups, and task forces to conduct technical research, as needed, and recommended the creation, through HERA and the Standards Board/Committee, of drafting teams comprised of industry experts to refine the information and recommendations contained in the RSWG final report.[182]

In 2014, the PUC issued its ruling on the RSWG work product, which included comments on HERA.[183] The PUC noted that the RSWG's work product was closely linked to HERA and the reliability standards developed by the Reliability Standards Development Group ("RSDG") (included within the RSWG final report) would likely transfer to HERA for implementation once approved. However, citing its "broad authority and discretion granted" by the HERA law, the PUC "decided to initiate its own framework addressing the purpose, scope, organizational structure of HERA ('HERA Framework'), which is under development."[184]

Notably, the Commission also stated its intent to open a new HERA docket and "propose the HERA Framework in that proceeding as a starting point to establish the issues for the docket and receive stakeholder input" via the opportunity to intervene or participate in the new HERA docket as provided by the Commission's rules of practice and procedure.[185] During the time that the HERA docket would be developed and proceed, the PUC intended to serve as HERA, until the official entity was formally established.[186]

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[180] *Id*. at 228

[181] *Id*.

[182] *Id*. at 229.

[183] Hawaii Public Utilities Commission, Order No. 32053 (Ruling on RSWG Work Product), Docket No. 2011-0206, issued April 28, 2014, at 111 (hereinafter "Ruling on RSWG Work Product").

[184] Ruling on RSWG Work Product at 112

[185] *Id.*

[186] *Id.* at 112-13.

The intent to open a HERA docket was also mentioned as recently as the Commission's annual report for FY 2014.[187] However, HERA was not the subject of any new dockets following the 2014 order, nor was it mentioned in subsequent annual reports. A possible explanation for this shift away from a highly researched, desired and authorized PUC process to create HERA may possibly be explained by the HECO Companies' proposed merger with NextEra that was announced in December 2014.[188] For example, in the PUC's 2015 annual report, Docket 2015-0022 regarding the HECO Companies and NextEra Energy Transfer / Merger was listed first in a short list of top priority dockets.[189] In its 2016 annual report, the PUC stated that

> *[t]he application for approval of the transfer of control of the Hawaiian Electric Companies to NextEra Energy required significant staff resources. After a 20-month review of more than 88,000 pages of filed documents, 22 days of formal evidentiary hearings, and seven public listening sessions on each of the main Hawaiian Islands, the Commission dismissed the application in a 2-0 decision shortly after the close of the fiscal year.*[190]

The report then listed the other energy-related dockets the Commission made progress on that year.[191] Regardless of the reason for the pause in the PUC's work on HERA, it is clear that the PUC is authorized to create HERA, and that it previously intended to open a docket specifically for this purpose.[192]

5.2.3 Steps and Timeline Approach

Because the process to create HERA is already underway, this study's approach to evaluating the steps and timeline necessary to implement HERA begins where the current process concluded. More specifically, this study does not contemplate the steps required to authorize the creation of the entity because such legislation has already been enacted. Because the PUC has already stated its intent to open a docket prior to and in order to create HERA, this study simply examines the

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[187] PUC Annual Report FY 2014 at 35. "The commission stated its intent to commence a new docket to evaluate and approve proposed reliability standards and that existing periodic electric reliability reporting will be expanded and consolidated to provide greater transparency of reliability performance related information."

[188] NextEra Energy, "NextEra Energy and Hawaiian Electric Industries to Combine," December 3, 2015, http://www.nexteraenergy.com/news/contents/2014/120314.shtml. The transaction was valued at approximately $4.3 billion and would have been one of the largest business deals in the state's history.

[189] PUC Annual Report FY 2015 at 9.

[190] PUC Annual Report FY 2016, executive summary at 1 (p. 3/83)

[191] *Id.*

[192] It is also important to note that the PUC is not required to implement HERA, nor is bound by its prior work on HERA. The statutory language uses the word "may" which grants authority without creating requirements, and there is nothing in the existing PUC work on HERA to suggest that the PUC is bound to its past work. However, it seems reasonable that the PUC would likely base future HERA work on previous HERA work, for the sake of efficiency.

typical Hawaii PUC investigative docket process for guidance on the steps and timeline necessary to implement HERA should it choose to do so.

5.2.4 Steps and Timeline Necessary to Implement HERA

As was stated above, the PUC is statutorily authorized to create HERA, received detailed information and suggestions for the development, organization, and responsibilities of HERA from the PUC-created RSWG, and had planned to open a HERA docket so that additional stakeholders like IPPs could participate in the creation of the HERA entity. During this preliminary development process, the PUC agreed to act as HERA until the entity is created. If the PUC were to pick up the process again, the Project Team anticipates that it would start by opening an investigative docket. The proceedings in PUC investigative dockets inevitably vary from docket to docket. Overall, common or consistent elements are detailed below. The average time for completion of a similar docket is around 2 years, although some take years longer, depending on the specific issue(s) at hand.

Figure 7. Steps and Timeline to Implement HERA

Summary of HERA Steps and Timeline	Action	Month
Step 1.	Open Investigative Docket	1
Step 2.	Initial Proceedings (Motions to intervene, motions to grant or deny intervention)	Month 1-18, 1-24
Step 3.	Issue Decision and Order regarding Conclusions on the Docket	Month 18-24
Step 4.	Address Outstanding Issues outlined in the Decision and Order (optional)	Months 18-24+
Step 5.	Create HERA according to the Decision and Order	Months 18-24
Step 6.	Review and Adjust HERA as necessary	Month 36 +

5.2.4.1 Step 1. Open an Investigative Docket

Under HRS § 269-7, the PUC is authorized to open investigative dockets and does so when it initiates its consideration of an issue on its own (or in response to a request for investigation, or

a legislative initiative directing the PUC to act)[193] rather than in response to an application from a utility.[194] At a minimum, the initial document usually contains background information and context for the investigation, states the relevant authority, states any named parties and procedural matters, and orders (including one order to initiate the investigative proceeding).

5.2.4.2 Step 2. Carry out proceedings of the investigative docket

Following the opening of the docket, interested stakeholders may apply to the Commission to become intervenors who are able to interact in the docket process. Motions to file for intervention are required to be served on all parties "no later than twenty days after the commission orders an investigation."[195]

Following the submission of these motions, the PUC will issue an order granting or denying intervention to the parties if the parties are determined to be sufficiently interested and do not unreasonably broaden the issues presented.[196] Although the PUC's response time may vary depending on the volume of motions for intervention they may receive for a particular document, it often takes the PUC several weeks to respond and issue an order granting or denying intervention to applicants.

Other proceedings can include, for example, requests for and issuances of protective orders, extensions, or additional information, the provision by the PUC of additional guidance or clarity on a particular issue or procedural matter, or submission of status reports or other work product (for example, the final report of the RSWG in Docket No. 2011-0206).

5.2.4.3 Step 3. Issue an order that details the PUC's conclusions based on the proceedings in the Investigative Docket

Once all the necessary information has been submitted to the Commission, the proceeding may be decided.[197] This typically results in a Decision and Order issued by the PUC, wherein the PUC

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[193] See e.g., Docket 2008-0273, Instituting a Proceeding to Investigate the Implementation of Feed-In Tariffs (filed Oct. 24, 2008 based on agreements between the HECO Companies and the Consumer Advocate, and the PUC's determination that such an investigation was appropriate); Docket 2008-0274, Instituting a Proceeding to Investigate Implementing a Decoupling Mechanism for [HECO Companies] (Oct. 24, 2014, also in response to agreements between HECO companies and the CA, as well as the PUC's determination that an investigation was appropriate); Docket No. 2010-0037, Instituting a Proceeding to Investigate Establishing Energy Efficiency Portfolio Standards, Pursuant to Act 155, Session Laws of Hawaii 2009 and Hawaii Revised Statutes § 269-96 (Mar. 8, 2010).

[194] For contrast, see Docket 2015-0389, Application for Approval to Establish a Rule to Implement a Community-Based Renewable Energy Program, and other related matters. (Filed Oct. 1, 2015 in response to 2015 Act 100, which required the utilities to file proposed community-based renewable energy (CBRE) tariffs with the PUC.)

[195] Haw. Admin. Rules § 6-61-57.

[196] Haw. Admin Rules § 6-61-55.

[197] Haw. Admin Rules § 6-61-119.

will discuss the issues and information brought forth during the proceedings and issue an order(s), usually related to the purpose of the docket. The substantive decision and order is often a lengthy document that is the result of careful thought and consideration by the PUC. In many cases, it can take around 12 – 24 months to issue the decision and order from when the docket is opened. For example, in Docket 2011-0206 regarding the Reliability Standards Working Group, the PUC ruling on the RSWG work product was issued on April 28, 2014, 13 months after the RSWG's Independent Facilitator ("IF") issued her final report, which included the voluminous work product of the RSWG,[198] and more than two years since the docket was opened on September 8, 2011.[199] In Docket 2010-0037 the docket was opened on March 8, 2010, and the Decision and Order approving a framework for energy efficiency portfolio standards was issued nearly 20 months later on January 3, 2012.[200]

5.2.4.4 Step 4. Address any outstanding issues directed by the Decision and Order

In some cases, a substantive Decision and Order does not conclude the docket. In these cases, the Decision and Order may request additional information from a party or parties before it is able to make its conclusions and close the docket. For example, in Docket 2010-0037, the January 3, 2012 Decision and Order approves the framework for energy efficiency but provides that "more specific direction and/or guidance related to the implementation of the principles addressed herein will be provided in future orders."[201] Indeed, subsequent Decisions and Orders in the docket relate to the creation of an Energy Efficiency Portfolio Standards Technical Working Group. Once the group began meeting on its own, and the elements of the procedural schedule for the docket were all met, the docket was formally closed in Order 30300 on April 4, 2012.

5.2.4.5 Step 5. Create HERA according to the Order

For the creation of HERA, once there is specific guidance provided through decisions and orders from the PUC (that will be informed by the participation of various intervenors who will likely include the members of the RSWG as well as IPPs), the PUC should work to contract with an appropriate entity to overtake the reliability and interconnection oversight responsibilities currently entrusted to the PUC and formally become HERA.

5.2.4.6 Step 6. Review and Adjust

Following the creation of a contracted HERA entity, the PUC will continue to oversee HERA. This is supported by the requirement that HERA submit annual reports of HERA's progress and

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[198] See Hawaii Public Utilities Commission, Docket 2011-0206., available at: https://dms.puc.hawaii.gov/dms/index.jsp,

[199] *Id.*

[200] See Hawaii Public Utilities Commission, Docket No. 2010-0037, available at: https://dms.puc.hawaii.gov/dms/index.jsp.

[201] Hawaii Public Utilities Commission, Decision and Order No. 30089 (Approving a Framework for Energy Efficiency Portfolio Standards), Docket 2010-0037, issued Jan. 3, 2012, at 14.

financial status.[202] Using this information and its authority to manage HERA, the PUC will monitor and make adjustments to HERA's duties and responsibilities as necessary.

5.2.5 Transition Costs of HERA

As has been stated elsewhere in the report, Hawaii can learn from the experiences of other jurisdictions in considering the transition to different regulatory models. In terms of the shift to HERA, this study has noted that legal authority for HERA already exists, that a PUC-authorized reliability provided suggestions on how the entity should operate, and that following the release of that study, the PUC stated that despite the recommendations in the study, the PUC would open its own HERA docket to determine the details regarding its implementation and operation. Although it is difficult to estimate the cost of implementing HERA via the docket process because public documents exclude those specific cost allocations, it is possible to estimate the expected start-up and operational costs by comparing HERA with similar bodies in other jurisdictions.

5.2.5.1 Cost Calculation Approach for HERA

To estimate the transition and operating costs of HERA,[203] the Project Team adopted the approach of scaling costs from similar mainland organizations based on the cost-per-kWh of system sales. While such a benchmarking-based approach is generally suitable for estimating costs of new organizations, Hawaii's relatively small electric grid does present complications, as a simple per-kWh scaling approach may overestimate the degree to which fixed organizational costs may be scaled to smaller jurisdictions (and therefore underestimate costs). To account for this, the Project Team has included a range of costs that account for a more conservative approach to cost scaling.

To estimate the operational costs of HERA, the Project Team used the costs of the North American Electric Reliability Corporation ("NERC") for comparison, due to the similarities between the two entities. NERC is a non-profit organization that was certified by the Federal Energy Regulatory Commission ("FERC") as its Electric Reliability Organization ("ERO").[204] The Federal Power Act ("FPA") required FERC to certify an ERO to develop mandatory and enforceable Reliability

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[202] Haw. Rev. Stat. § 269-149(b)

[203] The overall cost of HERA will likely be paid by all those who connect to the Hawaii electric grid through the surcharge that the HERA law authorizes the PUC to charge for all the operational costs (including administrative, technological, and other requirements of HERA). See Haw. Rev. Stat. §§ 269-146, 149. See also Section 5.2.1, Statutory Definition and Authority of HERA, *supra.*

[204] North American Electric Reliability Corp., 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030, *order on clarification and reh'g*, 119 FERC ¶ 61,046 (2007), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

See also, 157 FERC ¶ 61,043 at 1. "Section 215 of the Federal Power Act (FPA) requires the commission to certify an Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. In July 2006, the Commission certified NERC as the ERO."

Standards, subject to Commission review and approval.[205] NERC is also funded equitably by its end users throughout its jurisdiction.[206]

The Project Team looked to NERC's annual funding requirements and scaled the costs to the size of Hawaii's electric system. The Project Team acknowledges that this methodology has two shortcomings. First, the specific duties and areas of responsibility of HERA may not match those of NERC precisely, which could lead to inaccuracies in projecting the costs of HERA based on those of NERC. Second, directly scaling the costs of NERC (which manages a jurisdiction encompassing the contiguous United States, most of Canada, and a portion of Baja California in Mexico) to an entity responsible for the much smaller jurisdiction of Hawaii would ignore economies of scale in operating costs and may underestimate the costs of HERA. However, in the absence of better information on potential HERA operating costs, the team has relied on this methodology in this analysis.

The Project Team based HERA transition costs on the start-up costs of the Reliability Entity set up in the State of Texas (part of the Electric Reliability Council of Texas), which were available from a FERC report on the start-up and operational costs of Regional Transmission Organizations.[207]

As noted above, the team used a conservative scaling factor to account for the smaller size of Hawaii's electric grid than these reference cases. A scaling factor of 250% was drawn from the same FERC report as above (which provides estimated $/kWh impacts for RTOs serving both typical and small jurisdictions).[208]

5.2.5.2 Annual Funding Requirement of NERC at the federal level

NERC is required to submit budget proposals to FERC each year for review, comment, and approval. NERC states that its business plan and budgets are based on the following program areas that were originally listed in their application to become an ERO:

> *(1) Reliability Standards; (2) Compliance Monitoring and Enforcement Program and Organization Registration and Certification; (3) Reliability Assessment and System Analysis; (4) Performance Analysis; (5) Reliability Risk Management, which is comprised*

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[205] 16 U.S.C. § 824o (2012).

[206] 15 FERC ¶ 61,043 at 6, Docket No. RR16-6-000, Order Accepting 2017 Business Plans and Budgets (issued Oct. 20, 2016)

[207] FERC. "Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization." Docket No. PL04-16-000. October 2004.

[208] However, FERC's reference case for a small RTO market is its Desert Southwest region combining Arizona, Colorado, and New Mexico, with combined annual electric sales at of the time of 127 TWh/year. This is still approximately 10 times higher than the Project Team's Hawaii load forecast of 11.9 TWh/year.

of Situation Awareness and Event Analysis; (6) Electricity Information Sharing and Analysis Center; and (7) Training, Education, and Operator Certification.[209]

Since its designation as the ERO, NERC's annual net funding requirement for its United States operations has gradually increased overall, with some exceptions due to fluctuations in penalty payments. In 2016, NERC's net funding requirement (to be allocated in 2017) was approximately $155 million (including funding for regional bodies). Within the United States, NERC's costs are allocated to end users at a proportional per-kWh rate, which in 2016 was calculated as $0.0000389 per kWh (or $0.0000405 inflated to 2018 dollars).[210]

5.2.5.3 Reliability Organization Start-Up Costs

The Project Team used the start-up costs of ERCOT's Reliability Authority as the basis for the transition costs to the HERA model. In 2002, the start-up cost of this entity was $4.5 million ($6.4 million in 2018 dollars).[211]

5.2.5.4 Estimate of Operational costs of HERA in Hawaii

While the costs of NERC and ERCOT's Reliability Authority provide reasonable comparators to a HERA entity in Hawaii, there are several sources of uncertainty in any resulting cost estimate. First, at this stage in HERA's development, it is difficult to know if its program areas will align directly with those of reference organizations. As noted above, scaling the costs of NERC, which is active in all 48 contiguous states, and ERCOT's Reliability Authority to Hawaii introduces a source of error given the much smaller size of Hawaii's electric grid.

Scaling the per-kWh start-up costs of ERCOT's Reliability Authority and the operating costs of NERC directly to Hawaii's electricity sales yields a start-up cost (in 2018 dollars) of $234,000 and an annual operating cost of $483,000. To obtain a more conservative estimate that reflects Hawaii's smaller size, the Project Team applied FERC's 250% cost factor for small jurisdictions, yielding a start-up cost of $585,000 and an annual operating cost of $1.2 million. These costs are summarized in **Error! Reference source not found.** below.

Figure 8. Estimated HERA Transition and Annual Operating Costs

Figure 8. Estimated HERA Transition and Annual Operating Costs

[209] 15 FERC ¶ 61,043 at 4, Docket No. RR16-6-000, Order Accepting 2017 Business Plans and Budgets (issued Oct. 20, 2016)

[210] 157 FERC ¶ 61,043, Docket No. RR16-6-000, Order Accepting 2017 Business Plans and Budgets, issued October 20, 2016, available at: https://www.ferc.gov/whats-new/comm-meet/2016/102016/E-5.pdf at 3.

[211] FERC. "Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization." Docket No. PL04-16-000. October 2004.

Estimate	Transition Costs	Annual Operating Costs
Direct Scaling	$234,000	$483,000
Conservative Scaling	$585,000	$1,208,000

Relative to Hawaii PUC expenditures, estimated HERA costs are quite low. For example, in 2016, the PUC had Special Fund Revenues from Public Utility Fees that totaled $20.6 million ($21.5 million in 2018 dollars).[212] Based on the above calculation, HERA's funding need would be approximately 2% of that of the PUC under the direct scaling approach, and 6% under the conservative scaling approach. As noted above, it is possible that a more aggressive scaling factor is warranted given Hawaii's small size, in which case HERA costs would exceed these estimates.

5.2.6 Conclusions on Steps and Associated Costs for Conventional PBR + Light HERA Model

The transition from a COS to a PBR regulatory framework is one that will require a significant regulatory effort. These steps include making the decision to implement PBR, conducting extensive research and analysis to determine the appropriate PBR mechanism, setting in place data collection methods, conducting extensive stakeholder outreach (particularly with the utilities), evaluating PBR proposals, and issuing PBR decisions. The PUC is on a 21-month timeline from the state legislature, which is a shorter period of time to complete the steps used for either the Outcomes-based or Conventional PBR models, which have taken up to 30 and 33 months to complete in other jurisdictions, respectively. However, the Project Team anticipates that Hawaii may benefit from prior efforts and implemented PBR on a more efficient timeline (particularly if it is able to avoid several sources of delay that impacted timelines in Alberta and the UK). Hawaii has already published a schedule for implementing PBR that extends about 12 months from the initial Decision and Order initiating an investigation on PBR, and the steps already planned track closely with those used in Alberta.

5.2.7 Legal Considerations for HERA

Based on the PUC's broad statutory authority to engage in the supervision, guidance, and regulation of Hawaii's public utilities according to the public interest and to further the State's energy goals detailed in Section 4.3, as well as its explicit authority via recent legislation to implement HERA detailed in Section 5.2.1, above, it is clear that the PUC is authorized to open a HERA docket and to implement HERA as it sees fit. Thus, there are no gaps in the legal framework to enable the PUC to implement and regulate HERA.

[212] PUC annual Report 2016. Note that while the commission revenues are much higher than commission expenses, the commission is obligated to return send excess funds to other agencies (like the Consumer Advocate) and to the State's General Fund.

5.3 DSPP

The Distributed System Platform Provider ("DSPP") regulatory model requires the utilities to provide open access to distributed energy resources ("DER") and other providers by offering energy management or customer data analytics services. As DSPPs, the utilities essentially become the purchasers and aggregators for DER by upgrading the distribution network and then creating markets, tariffs, and operational systems to enable behind-the-meter resources to monetize products and services. Using this modernized grid platform provided by the DSPP utilities, customers, service providers, DER, and utilities conduct transactions of energy and services. Although the use of this model has the potential to increase the amount and costs of regulatory oversight, this model also expands the potential to open new revenue streams and to encourage the use of more DER.

In contrast to its position on the PBR regulatory model, Hawaii does not currently have a prior commitment to DSPP. Similarly, in contrast to its position on the HERA regulatory model, Hawaii has also not explicitly authorized (without requiring implementation of) the DSPP model. However, the Project Team's analysis in Task 2.2.6 revealed that use of DSPP in conjunction with Outcomes-based PBR (discussed in Section 5.1.1, above) and an IGO (discussed in Section 5.4, below) may comprise a preferable regulatory model for Hawaii to pursue due its ability to support a competitive distribution system, which will help control costs and rate volatility, efficiently allocate resources, fairly distribute risks, and fulfill state energy goals. Because Hawaii has not begun any planning or implementation process, this section examines all the steps, timeline, costs, and legal changes necessary to implement DSPP.

5.3.1 Steps and Timeline Approach for Transition to DSPP

The shift from utilities operating under the existing COS regulatory framework as vertically integrated entities to undertaking an additional role of DSPP requires significant regulatory work and efforts by the utilities. Due to the novel nature of the DSPP regulatory model, the State of Hawaii is well served by referring to another U.S. jurisdiction that is in the process of implementing DSPP. In determining the steps and timeline required for DSPP design and implementation, the Project Team concludes the regulatory shift occurring in New York State provides a particularly useful example.

Since 2014, New York ("NY") has been in the process of a significant regulatory change, which it calls Reforming the Energy Vision ("NY REV").[213] NY REV was created through the joint efforts of NY Governor Andrew Cuomo, the NY Public Service Commission ("PCS"), the New York Power Authority ("NYPA"), and other state agencies in response to the devastating effects of

[213] "Governor Cuomo Announces Fundamental Shift in Utility Regulation," April 24, 2014, https://www.governor.ny.gov/news/governor-cuomo-announces-fundamental-shift-utility-regulation

Hurricane Sandy, which hit the NY area in October 2012.[214] Recognizing an urgent need to offset the effects of climate change by decarbonizing and making the grid more resilient, efficient, and economic, the State began the redesign of the regulatory system through the REV proceeding.[215] Specifically, under REV, regulators are able to transform traditional utilities into DSPPs, meaning the utilities facilitate the use of DER for use instead of tradition utility infrastructure to provide power to customers.

This transition for utilities to function as DSPPs is intended to address the oversized bulk power system in existence under the original model, which was designed to meet the relatively limited number of peak demand periods each year, as well as decrease costs and increase use of renewable energy sources, which are often distributed.[216] Other REV goals, which are achievable at least in part by the DSPP element of the model, include:

- Making energy affordable for all New Yorkers
- Building a more resilient energy system
- Empowering New Yorkers to make more informed energy choices
- Creating new jobs and business opportunities
- Improving our existing initiatives and infrastructure
- Supporting cleaner transportation
- Cutting greenhouse gas emissions 80% by 2050
- Protecting New York's natural resources
- Helping clean energy innovation grow[217]

To achieve these goals, the REV promotes the more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar, broader deployment of DER such as microgrids, roof-top solar, and other on-site power supplies, and storage. REV also encourages markets to achieve greater use of advanced energy management products to enhance demand

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[214] Other agencies include the New York Energy Research and Development Authority ("NYSERDA") and the Long Island Power Authority ("LIPA"). "About REV," https://rev.ny.gov/about/, accessed Sept. 21, 2018.

[215] Gavin Bade, Zibelman exit interview: how the New York REV is paving the way for transactive energy, Feb. 1, 2017, https://www.utilitydive.com/news/zibelman-exit-interview-how-the-new-york-rev-is-paving-the-way-for-transac/435252/

[216] NY REV supports the State's energy goals for 2030, which include a 40% reduction in GHG emissions from 1990 levels, a requirement that 50% of electricity must come from renewable sources, and a 23% decrease in energy consumption in buildings from 2012 levels (a 600 trillion Btu increase in statewide energy efficiency (at source)). https://rev.ny.gov/

[217] New York Dept. of Public Service, "Reforming the Energy Vision: About the Initiative," http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument

elasticity and efficiencies, which ultimately will empower customers to choose how they manage and consume electric energy.[218]

To determine the steps and timeline undertaken by New York to implement DSPP through the REV, the Project Team assessed the relevant documents from the NY REV docket proceedings and other related publications.

5.3.2 Steps and Timeline Necessary to Transition to DSPP

The Project Team's assessment of the steps and timeline necessary for the transition to a DSPP model is primarily informed by the experience of New York, which began the process of planning for and implementing DSPP in late 2013. Since the announcement that New York would undergo a comprehensive reconsideration of its regulatory framework, the state has initiated a large proceeding over the course of the past four years (including several additional dockets related to different elements of the regulatory framework) and worked with utility companies and other relevant stakeholders to plan and implement the various elements of the overall REV model, including the transformation of utilities to Distributed System Platforms. Although the proceeding is still ongoing and involves a redesign of the ratemaking process, this section focuses on the process undertaken by the state to transform the utilities into DSPPs.

At the time of this writing, the Project Team concludes that the Department of Public Service ("DPS") and the PSC had created a Distributed System Implementation Plan Guidance document, the utilities, and the PSC approved joint and individual Distributed System Implementation Plans ("DSIPs"), and the utilities have designed and implemented Demonstration Projects in their various service areas. Thus, New York and its utilities have laid considerable groundwork for the implementation of the DSPP model but have not yet fully implemented the model and have also not set a definitive deadline for the utilities to be fully functioning as DSPPs.

As discussed in Section 5.3.3, HI is a significantly smaller state than New York, and the utilities in most of the islands are under the same parent company, and therefore would probably require less time to implement the DSPP. Furthermore, the time spent on some of the steps taken by the NY DPS might be compressed in Hawaii.

A summary of the completed steps is listed in Figure 9, below.

Figure 9. Steps and Timeline to Implement DSPP in NY

[218] *Id.*

Summary of DSPP Steps and Timeline Already Taken	Action	Month
Step 1.	Statement of Intent to make a regulatory change and initial investigation	Month 1
Step 2.	Initial investigation; Opening of new regulatory proceeding	Months 1-4
Step 3.	Establish a preliminary schedule and approach for proceeding	Month 5
Step 4.	Stakeholder engagement and continued development of the REV	Months 5-14
Step 5.	Publication of initial proposals for regulatory changes	Month 9
Step 6.	Commission and utilities prepare additional mechanisms	Month 12
Step 7.	Issuance of an order adopting a policy framework and implementing a plan	Month 14
Step 8.	Development of REV demonstration projects	Months 18-23
Step 9.	Development of DSIP Guidance and Plans	Months 22-37
Step 10.	Continued planning under the adopted policy framework and implementation plan	Month 14+ (ongoing)

Source: New York Department of Public Service

5.3.2.1 Step 1. Statement of intent to make a regulatory change and initial investigation

In Month 1 in an Order dated December 26, 2013, in another proceeding,[219] the PSC directed the DPS Staff[220] to begin a process that would comprehensively reconsider New York's regulatory system and whether its retail and wholesale market designs were effectuating or impeding progress toward achieving the foundational policy objectives of the existing regulatory

[219] New York Department of Public Service, Case 07-M-0548, Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard, Order Approving EEPS Program Changes, issued December 26, 2013. At 21

[220] Throughout the proceeding, DPS support the work of the PSC in an advisory capacity.

framework. The order then identified two key questions for consideration in a new regulatory proceeding that would assess and improve upon the regulatory framework:

a) *What should be the role of the distribution utilities in enabling system-wide efficiency and market-based deployment of distributed energy resources and load management?*

b) *What changes can and should be made in the current regulatory, tariff, and market design and incentive structures in New York to better align utility interests with achieving our energy policy objectives*?[221]

In addition to the primary questions to be answered, the Order also provided key policy outcomes desired, which are well indicated by the REV goals, listed in Section 5.3.1 above. The statements made in this Order constitute the statement of intent to assess the regulatory framework and to likely make sweeping changes, making way for the opening of the REV proceeding.

5.3.2.2 Step 2. Initial investigation; Opening of new regulatory proceeding

In Months 1–4, following the initial statement of intent and direction to the DPS Staff to consider the existing regulatory framework in the context of state policy goals, the PSC opened the REV proceeding docket (14-M-0101) on April 14, 2014. Attached as an appendix to this order was a report that was developed by DPS Staff at the instruction of the 2013 order above during the five months between that order and the initiation of the REV proceeding.

The report describes the implications of new trends in energy and climate change on the PSC's regulatory responsibilities. The report also describes a new business model for energy service providers (the DSPP model) in which DER "become a primary tool in the planning and operation of electricity systems, and in which customers are empowered to optimize their priorities with respect to reliability, cost, and sustainability."[222] The report also acknowledges the steps the state had already taken toward a distributed grid architecture and the evolution of the regulatory paradigm[223] and asks questions related to the functions of the DSPP to be addressed during the proceeding.

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[221] *Id*. at 23

[222] New York Department of Public Service, Order Opening the REV proceeding, Case 14-M-0101, April 24, 2014 at 4.

[223] These include:

- DR at the distribution level, cooperation with NYISO bulk level demand response programs,
- PBR incentives – negative adjustments for failure to meet minimum service thresholds,
- Revenue decoupling mechanisms that make utilities indifferent to changes in sales volume that may result from customers adopting energy efficiency and distributed generation
- Interconnection standards of customer-sited generation connected to the distribution system
- Standby rates (to have utility available as a backup)
- Time of use rates (voluntary for smaller customers) to encourage off-peak usage
- Gas delivery rates for customers w/ DG

Notably, the report did not set a timeline or deadline for implementation of REV and the DSPP model. Instead, it set only preliminary deadlines for status reports on each Track of the project (due July 2014) and generic policy decisions for each (September 2014 for Track One, First Quarter 2015 for Track 2),[224] and highlighted the time-intensive nature of preparing and implementing the REV.[225]

5.3.2.3 Step 3. Establish a preliminary schedule and approach for proceeding

In Month 5, an Administrative Judge for this proceeding worked with the stakeholders to establish an initial schedule for the next several months. The schedule included working group meetings, technical conferences, and the issuance of a straw proposal for each track by DPS staff, and party comments to the proposals.[226]

5.3.2.4 Step 4. Stakeholder Engagement and continued development of the REV

In Months 5 - 14 and ongoing, following the initiation of the proceeding and establishment of a timeline for initial tasks, the PSC and DPS received comments from stakeholders including the utility companies and the NYISO. Nearly 300 parties participated in these collaborative efforts and offered informal guidance on major policy issues. Under the leadership of two administrative law judges, the parties formed two working groups and five committees (markets; customer engagement; platform technology; microgrids; wholesale markets). In July 2014, these groups filed reports with the PSC and presented results at a technical conference before the Commission. They were also invited to submit preliminary comments on policy issues to guide the DPS Staff's

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- Energy efficiency programs
- Customer sited clean energy programs under the RPS
- Advanced energy technology research and development programs
- A green bank to facilitate financing of advanced energy projects
- Implementation of statutory net metering requirements.

Case 14-M-0101. Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, DPS Staff Report and Proposal, at 10.

[224] Track One began immediately and focused on the DSPP issues detailed in the report. The status report on these issues was due July 10, 2014. The Staff also stated a goal to reach a generic policy determination on DSPP by the end of 2014.

Track Two focuses on regulatory changes and ratemaking issues. It is conducted in parallel to Track One, but does not adhere to the same deadlines. The initial Staff straw proposal was anticipated by mid-July, 2014, to be followed by a collaborative discussion of the issues, and a status report on regulatory reform issues on September 4, 2014. The PSC expected to reach a generic policy determination on this Track in the first quarter of 2015. Order Opening REV Proceeding, at 6-7.

[225] *Id*. at 65

[226] Case 14-M-0101, Ruling Establishing Collaborative Agenda and Working Schedule, Issued May 1, 2014.

development of their proposals.[227] Following the Commission's issuance of the straw proposal and notice of proposed rulemaking, as well as the draft generic EIS, stakeholders were able to provide comments. The Commission also held public statement hearings throughout the state,[228] as well as a second technical conference in Month 11.

5.3.2.5 Step 5. Publication of initial proposals for regulatory changes

In Month 9, the PSC published the straw proposal for Track One (August 22, 2014) (Track Two, was delayed). Following this publication, stakeholders continued to submit comments and engage in the planning process.

5.3.2.6 Step 6. Preparation of additional mechanisms by the Commission and the utilities

On December 11, 2014, (Month 12 of the process) the Commission ordered each utility to develop a demand response tariff, to participate in ongoing efforts to establish dynamic load management measures and to adhere to a Resolution issued by the Commission for guidance on demonstration projects. The Commission also initiated a process to examine long-term alternatives that would accomplish the purpose of net metering more efficiently.

5.3.2.7 Step 7. Issuance of Order Adopting Policy Framework and Implementing Plan

On February 26, 2015 (in Month 14 of the process), the Commission issued and put into effect an Order Adopting Policy Framework and Implementing a plan for the Track One policy issues, including the development of the DSPP. The order summarized all previous work done and ordered the creation by the utilities of DSIPs and provided guidance on what the DSIPs must include, as well as a schedule for additional REV implementation matters.

5.3.2.8 Step 8. Development of REV demonstration projects

Beginning in month 18 by the February 26, 2015 Order of the Commission, the joint utilities began submitting proposals for demonstration projects, which are intended to exhibit new business models that fit within the REV framework. Specifically, these projects should inform decision makers related to developing DSP functionalities, measuring customer responses to various programs and prices associated with the REV model, and to determine the most effective implementation of DER.[229] DPS began releasing assessments of some demonstration projects in month 23. During the entire period and through the current date, utilities have begun operations of approved demonstration projects, and have also submitted applications for new ones.

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[227] Order Adopting Regulatory Policy Framework and Implementing Plan, Case 14-M-0101, issued and effective Feb. 26, 2015.

[228] Public statement hearings were conducted in Buffalo, Syracuse, Albany, Kingston, Binghamton, Rochester, Yonkers, and New York City.

[229] New York Department of Public Service, "REV Demonstration Projects," http://www3.dps.ny.gov/W/PSCWeb.nsf/All/B2D9D834B0D307C685257F3F006FF1D9?OpenDocument

Following operation of a demonstration project, the utility must (and does) submit status updates or quarterly reports to the Commission.

5.3.2.9 Step 9. Development of Distributed System Implementation Plan Guidance and Plans

Beginning in Month 22, the DPS published a proposal for DSIP guidance, and the joint utilities filed their comments nearly two months later. The DSIP guidance was later adopted in month 28 on April 20, 2016. Then in Month 37, on March 9, 2017, the Commission released an order on Distribution System Implementation Plan Filings. The Order required utilities to submit filings by October 1, 2017, to document that the hosting capacity analysis for all circuits at and above 12kV had been completed and that Phase 1 of the interconnection portals had been fully implemented.

The Order also required utilities to show within 60 days that all sustainability criteria will be incorporated into the utility planning procedures and capital plans, and within 90 days all proposed building energy management and benchmarking data standards for the Commission's consideration. Finally, the order required utilities to file documentation of deploying energy storage projects that are operating at no fewer than two separate distributions substations or feeders, as discussed in the order by December 31, 2018.

5.3.2.10 Step 10. Continued Planning under the Adopted Policy Framework and Implementation Plan

In Months 14 and onward, following the Commission's adoption of a policy framework and implementation plan, the Commission, and the parties continued to work to continue to develop the framework according to the plan. Two examples of this are the joint utilities submission of a technical resource manual management plan on June 1, 2015, and the publication by the DPS staff of the Benefit-Cost Analysis ("BCA") Framework Whitepaper. Both submissions were then open to a comment period and subsequent revisions and approvals. In particular, the BCA whitepaper, which received comments on August 21, 2015, was then used by the Commission to establish the BCA Framework on January 21, 2016. The BCA Framework required the joint utilities to file BCA handbooks by June 30, 2016, in compliance with that order.

This process was repeated throughout the following months through to the current day for other issues including setting standards for a code of conduct, an interconnection earning adjustment framework and voluntary time of use rates.

5.3.2.11 Anticipated Next Steps

Although it is difficult to determine what the next steps for the PSC are regarding the planning and implementation of the DSPP model, it is clear that certain tasks must occur. The Project Team anticipates a continuation and expansion of the demonstration projects, as well as continued development and improvement on the various mechanisms identified as necessary to implement the DSPP model. Because no ultimate deadline was published, nor a comprehensive status update in terms of current progress as part of the completed initiative, the Project Team is unable to determine how long the proceeding will continue before DSPP is actually in effect among all the utilities. The PSC has also noted that this process will be time consuming and ongoing.

5.3.3 Steps and Timeline to Implement DSPP in Hawaii

Based on the analysis of New York's ongoing process to implement DSPP as part of the REV initiative, it is clear that the regulatory transition to DSPP is a time consuming and complex endeavor. It is also clear that the process used by New York is very collaborative, utilizing the expertise and opinions of relevant state agencies, legal experts, nonprofits (as intervenors) and the utility companies. New York undertook many different initiatives to assess, draft, reassess and implement various elements of the REV and DSPP regulatory models, which inherently requires time for all the parties to meaningfully participate, and for the utilities and the PSC, in particular, to make the appropriate changes in their plans and operations.

Although New York has made significant progress towards implementing DSPP over four years, the PSC noted that the process would be ongoing, and in fact, the PSC and utilities have not yet completed the full transition. Notably, although Hawaii's regulatory scene has its own complexities, Hawaii is a significantly smaller state than New York, with fewer utilities and a smaller grid to work with as it develops such a model. With this in mind, the Project Team projects that if Hawaii were to undertake similar steps as New York, it would be able to implement DSPP by 2028.

5.3.4 Transition Costs of DSPP

The transition costs of a DSPP model are highly uncertain as the primary precedent for the model (the New York REV process) has not yet been fully implemented. This analysis primarily considers the costs that would be borne by Hawaii's utilities in the transition to a DSPP model. In addition to these direct transition costs, Hawaii's utilities and PUC alike would incur costs related to the lengthy process to plan the transition to a DSPP model.

5.3.4.1 New York REV Demonstration Project Budgets

While the full costs of implementing the DSPP model in New York are not yet known, budgetary information from early REV demonstration projects that are similar in nature to the DSPP model that would eventually be implemented across Hawaii provides key insights to the state's potential transition costs. One such demonstration project, National Grid's Distributed System Platform demonstration project in Buffalo, New York, forms a key data point in the determination of potential costs. This project, located on the Buffalo Niagara Medical Campus, is designed deploy many of the DSPP concepts included in REV (such as the locational value of customer generation resources, and the development of a platform to allow these assets to provide grid services) on a pilot basis.[230]

[230] Niagara Mohawk Power Corporation D/B/A National Grid: Distributed System Platform Rev Demonstration Project – Q2 2018 Report, Case 14-M-0101. July 31, 2018.

The National Grid demonstration project is designed to serve a potential distributed resource capacity of 63.5 MW across several locations.[231] National Grid initially budgeted $4.81 million for a three-year implementation project, $3 million of which would go to a third party software provider (after accounting for a $2 million cost share), and $1.81 million of which would cover National Grid's own costs (on an annual basis, these costs equate to $1 million in software development costs and $603,000 in internal costs. After the start-up period, National Grid anticipated annual operating cost of $200,000 in software licensing and $30,000 in utility expenditures. [232] Through June 2018, the demonstration project is two-thirds of the way through the pilot start-up period and has spent 55% of its project budget.[233]

5.3.4.2 Estimate of Operational Costs in Hawaii

The Project Team scaled these costs of implementing the DSPP model in the Buffalo pilot project to Hawaii by the amount of distributed generation resources served – direct software costs were not scaled as these were assumed to be a relatively fixed cost. In HECO's Power Supply Improvement Plan, the utility projects 1,698 MW of DG capacity to be implemented in 2045 (this number excludes Kauai, for which a formal utility-published DG forecast is not available).

Scaling these the costs of the Buffalo REV demonstration project directly from the 63.5 MW of targeted capacity from the Buffalo pilot to the 1,698 MW targeted capacity in Hawaii would result in an annual cost of $17.1 million during the three-year start-up period (including $1 million annually in software costs), and $1 million in annual operating costs following the start-up period (including $200,000 in software costs).

5.3.5 Conclusions on Steps, Timeline, and Costs for Transition to DSPP

The transition from a vertically integrated utility model to including DSPP has been experienced and documented to the extent necessary for comparison only by New York's REV proceeding, which consists of the creation of a DSPP model. Additional uncertainty in the steps, timeline, and cost arise from the fact that New York is still in the process of implementing the DSPP. However, the Project Team notes that steps Hawaii might anticipate in creating a DSPP model include stating an intent to make the regulatory change, opening an investigation and regulatory proceeding, establishing a schedule and engaging stakeholders, creating and publishing guidelines and policy frameworks, and possibly developing demonstration projects. Based on New York's timeline, the Project Team estimates these initial processes of developing a policy plan and other elements of the plan could take up to three years due to the complexity and novelty of the topic. However, it is also possible that the initial startup will require less time since Hawaii is significantly smaller and has fewer regulatory players than New York does. Regardless, this

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[231] Niagara Mohawk Power Corporation D/B/A National Grid: Distributed System Platform Rev Demonstration Project – Q2 2018 Report, Case 14-M-0101. July 31, 2018.

[232] Niagara Mohawk Power Corporation D/B/A National Grid: Implementation Plan for Distributed System Platform REV Demonstration Project, Case 14-M-0101. August 15, 2016.

[233] *Id.*

tentative deadline leaves sufficient time for completion by 2028 to implement DSPP. In terms of costs, despite significant uncertainty, the Project Team estimates that the cost to implement the DSPP model to be will be $51.4 million, spread over three years, with a $1 million annual operating cost thereafter.

5.3.6 Legal Considerations for DSPP

In contemplating whether to implement the DSPP model in Hawaii, it is important to consider whether a legal framework exists in Hawaii that permits its implementation. In particular, it is essential to take into account whether the state has the authority to impose the DSPP model on the utilities and whether it has the power to regulate the utilities as DSPPs. In this analysis, Project Team considers both the legality of the existing DSPP model currently being implemented in New York, as well as the current legal framework in Hawaii and any legal changes that may be necessary.

5.3.6.1 Legal Framework for DSPP in New York

New York has begun planning for and implementing the DSPP model as part of the REV initiative, as discussed above. In the Order Adopting Regulatory Policy Framework and Implementation Plan, the PSC noted the authority derived from New York statutes and case law that provide the authority for the REV proceeding.[234] One statute highlighted in the order is Public Service Law ("PSL") section 65(1), which provides that the Commission is responsible for ensuring that electric corporations "furnish and provide such service, instrumentalities and facilities as shall be safe and adequate and in all respects just and reasonable."[235] The other statute referenced is PSL section 5(2), which states:

> *The Commission shall encourage all persons and corporations subject to its jurisdiction to formulate and carry out long-range programs, individually or collectively, for the performance of their public service responsibilities with economy, efficiency, and care for the public safety, and preservation of environmental values and the conservation of natural resources*.[236]

Additionally (though not specifically highlighted in the Order), the jurisdiction, power and duties of the PSC extend to "the manufacture, conveying, transportation, sale or *distribution* of gas (natural or manufactured or mixture of both) and electricity for light, heat or power, to gas plants and to electric plants and to the persons or corporations owning, leasing, or operating the

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[234] Order Adopting Regulatory Policy Framework and Implementation Plan, Case No. 14-M-0101, February 26, 2015

[235] *Id.*; NY Pub. Serv. L. § 65(1).

[236] NY Pub. Serv. L. § 5(2).

same."[237] Although ratemaking is not explicitly included under this statute, it is confirmed to be included as part of the PSC's authority as well.[238]

Based on these statutes and case law, it is clear that the NY PSC has the authority to regulate utilities in their traditional role, as well as their developing role as distribution service platform providers. It is also clear that the Commission has the authority to ensure safe and adequate utility service and to carry out long-range planning programs, such as the REV. Additionally, the New York courts have concluded that the Commission has the responsibility "to adjust its regulatory framework in response to the evolving circumstances and foreseeable trends, in order to meet customers' needs," and these adjustments "may include innovative, market-based tools and the formation of new business models."[239] Indeed, the PSC's actions to introduce competition into a monopolistic marketplace to lower prices to consumers, as well as the PSC's actions to require energy efficiency and demand management programs have been upheld by the court.[240] Finally, as an executive agency, the PSC enjoys judicial deference under administrative law principles.[241]

It is worth noting that aside from legislation codifying the state's energy plan,[242] the requirement that every agency of the state conduct its affairs so as to conform to the state energy policy,[243] and the REV proceeding itself,[244] no new legislation was introduced in order to legalize or enable the process of implementing DSPP or the REV initiative more generally. Additionally, at the time of this writing (nearly four years into the proceeding), it appears that the effort has not been challenged, and all relevant agencies and utility companies are engaging in the process to implement the REV and the DSPP model. Therefore, the Project Team concludes that the legal framework in place in New York is sufficient to enable the PSC to plan for, implement, and regulate under the REV model, including the creation and use of DSPPs.

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[237] NY Pub. Serv. L § 5(1)(b) (Emphasis added).

[238] Porr v. NYNEX Corp. (2 Dept. 1997) 230 A.D.2d 564, leave to appeal denied 91 N.Y.2d 807, 669 N.Y.S.2d 260, 692 N.E.2d 129.

[239] Order Adopting Regulatory Policy Framework and Implementation Plan, Case No. 14-M-0101, February 26, 2015, citing Cases 94-E-0952 et al., Competitive Opportunities Regarding Electric Service, Opinion and Order Regarding Competitive Opportunities for Electric Service (issued May 20, 1996), and Energy Ass'n of New York State v. Public Serv. Comm'n of the State of New York, 169 Misc. 2d 924 (Albany County Sup. Ct. 1996).

[240] Energy Ass'n of New York State v. Public Serv. Comm'n of the State of New York, 169 Misc. 2d 924, 936 (Albany County Sup. Ct. 1996).

[241] *See,* Multiple Intervenors v. Public Service Commission of the State of New York, 154 A.D.2d 76 (3d Dept. 1991).

[242] NY Energy § 6-104; Specific regulations reflective of the content in the 2015 State Energy Plan codified in 9 NYCRR §§ 7840.1 – 7863.1.

[243] NY Energy § 3-103.

[244] Case 14-M-0101.

5.3.6.2 Legal Framework for DSPP in Hawaii

As was stated above in Section 4.3.3, the Hawaii Public Utilities Commission ("PUC") has general supervision over all public utilities and must perform the duties and exercise the powers imposed or conferred upon it by law.[245] This includes regulating rates, opening investigations, and acting as an enforcement agency for the regulated entities, all in the furtherance of the public interest. In addition to these responsibilities, the Commission is also required to consider other regulatory impacts in the context of achieving the State's energy goals.

Under this regulatory framework, "public utilities" are defined as including any entity "who may own, control, operate, or manage…any plant or equipment, or any part thereof… for the production, conveyance, transmission, delivery, or furnishing of light, power, heat, cold, water, gas, or oil."[246] Section 4.3.3 also discussed how this legal description qualified the HECO Companies and KIUC as public utilities for the purpose of the statutory framework. Additionally, a careful reading of this definition includes, as it did in the New York statute, entities that transmit or deliver power. This language is important because, on its face, it includes PUC regulation of the utility companies even if their roles shift to DSPPs, as proposed in this model.

Based on the laws that inform the PUC in its regulation of public utilities, as well as the nature of the DSPP model, it appears that the extension or evolution of the utility companies' duties to become the purchasers and aggregators for DER and to engage in activities that enable behind-the-meter resources to monetize products and services would fall under the PUC's regulatory purview. Additionally, this kind of model is part of the regulatory shift specifically contemplated by the PUC in its 2014 whitepaper, the Commission's Inclinations on the Future of Hawaii's Electric Utilities.[247] In the Inclinations, the Commission articulated the role of "modern transmission-and-distribution systems integrator" as a key business function for the utility companies of the future in Hawaii. The paper details "[this] business strategy focuses on energy delivery would enable the HECO Companies to concentrate on developing a world-class, modern island grid infrastructure to accommodate and deliver substantial quantities of clean energy sources."[248] Therefore, the Project Team concludes that there is likely no legal action required for the Commission to lawfully implement the DSPP model.

However, the Project Team also notes that due to the novel nature of the regulatory model, the timeframe in which the transition to DSPP will likely occur (implementation in 2028), and the approach the state has taken to other regulatory shifts or initiatives, the state could benefit from passing legislation that requires a transition to DSPP to the extent that is the preferred model.

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[245] Haw. Rev. Stat. § 269-6

[246] Haw. Rev. Stat.§ 269-1(1)

[247] The Inclinations at 1.

[248] *Id.* at 21.

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This would follow the same example as the PBR law,[249] in which the legislature created a requirement to shift to a specific regulatory model even though the PUC could engage in such a transition on its own. The Project Team anticipates that such legislation would be viewed as aligned with the state's energy goals and would be a timely step in the implementation of DSPP. This step should create clarity and ease for the parties and would help to prevent the possibility of any future legal challenges.[250]

5.4 IGO

An Independent Grid Operator ("IGO") is an independent entity that manages the dispatch and planning functions. The IGO would be able to manage both transmission and distribution assets due to the relatively small size of these in Hawaii. This is in contrast to ISOs, detailed below, which manage transmission assets only on a much larger scale. Additionally, the IGO helps to address conflicts of interest and ensure impartiality in interconnection and reliability analyses. This function may be particularly useful when implemented together with the DSPP model, above, due to the increased likelihood of conflicts of interest for the utility as and greater complexity of the grid that are probable under that model.

IGOs are comparable to Independent System Operators ("ISOs") that exist in other parts of the country. Even though most ISOs on the US mainland are regulated by FERC and that any Hawaii IGO would not be regulated by FERC, the Project Team finds this comparative analysis valuable due to the broad functional similarities a Hawaii IGO is anticipated to have with a FERC regulated ISO/RTO. ISOs were conceived of by the FERC as a method to "remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity customers."[251]

As envisioned by FERC in its 1996 Order 888, the ISOs are purposed with operating the transmission systems of public utilities in a way that is independent of any business interest in sales or purchases of electric power by those utilities.[252] In a later order, FERC amended its regulations under the Federal Power Act ("FPA") to advance the formation of Regional Transmission Organizations ("RTOs"). Under the new regulations, FERC codified the minimum characteristics and functions for the RTOs and required that each public utility or other entities engaged in interstate energy transmission make certain filings with respect to forming and

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[249] Hawaii Ratepayer Protection Act.

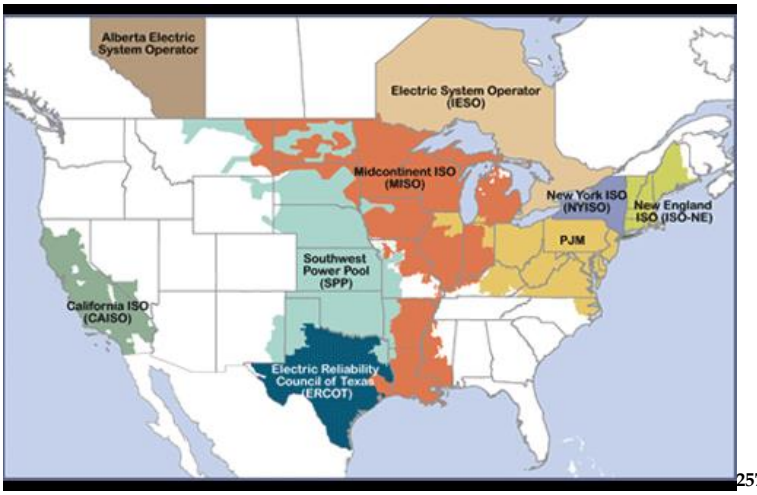
[250] The Project Team emphasizes that DSPP appears to be legal under the existing framework. Nonetheless, legal challenges can present a time-consuming and expensive challenge regardless of their merits.

[251] 75 FERC ¶ 61,080 (FERC Order 888, Issued April 24, 1996, at 1)

[252] 75 FERC ¶ 61,080 (FERC Order 888, Issued April 24, 1996, at 280). Note also that Order 889, also released on April 24, 1996, amended rules establishing and governing the Open Access Same-Time Information System (OASIS) and prescribed standards of use and access for the system as a means to provide open access to transmission and transmission information.

participating in an RTO.[253] ISOs are also similar to RTOs, although are not held to the same degree of responsibility by FERC.[254] The distinction between RTOs and ISOs is that ISOs can be formed at the direction or recommendation of FERC, but might not meet FERC's minimum requirements of an RTO, or have not petitioned FERC for the status to become an RTO. However, it appears that most existing ISOs[255] are also characterized together with RTOs by FERC.[256]

Figure 10. FERC Map of RTOs/ISOs



[257]

[253] 89 FERC ¶ 61,285 (FERC Order 2000, issued Dec. 20, 1999, at 1). The minimum characteristics and functions that an RTO must satisfy are:

Minimum Characteristics:
1. Independence
2. Scope and Regional Configuration
3. Operational Authority
4. Short-term Reliability

Minimum Functions:
1. Tariff Administration and Design
2. Congestion Management
3. Parallel Path Flow
4. Ancillary Services
5. OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC)
6. Market Monitoring
7. Planning and Expansion
8. Interregional Coordination

[254] Compare, FERC Order 888 and FERC Order 2000; However, both ISOs and RTOs within FERC's jurisdiction are subject to NERC oversight. 16 U.S.C. § 824o (2012).

[255] This excludes the Electric Reliability Council of Texas ("ERCOT"), which is not registered with or subject to FERC's jurisdiction. See Section 5.4.2.3, infra.

[256] FERC, Regional Transmission Organizations (RTO) / Independent System Operators), accessed Sept. 25, 2018, https://www.ferc.gov/industries/electric/indus-act/rto.asp?csrt=2042728201376846909. Based on the available map, it appears that the PJM Interconnection and the Southwest Power Pool are the only two entities that are exclusively RTOs.

[257] *Id.*

As was true with the DSPP model (and in contrast to the PBR and HERA models), Hawaii does not currently have a prior commitment to creating an IGO. However, the Project Team's analysis in Task 2.2.6 revealed that use of an IGO in conjunction with an Outcomes-based PBR (discussed in Section 5.1.1, above) and the DSPP model (discussed in Section 5.3, above) may achieve most of the state goals due to its ability to support a competitive distribution system, which will help control costs and rate volatility, efficiently allocate resources, fairly distribute risks, and state energy goals. Because Hawaii has not begun any planning or implementation process for an IGO, this section examines all the steps, timeline, costs, and legal changes necessary to create an IGO.

5.4.1 Steps and Timeline Approach for Creation of an IGO

Because Hawaii has not previously made efforts to create such an entity as part of its regulatory framework, it is useful to draw on the processes undertaken by other states that have an ISO. In particular, the Project Team examines the steps, timeline, costs, and legal considerations of the New York for the New York Independent System Operator ("NYISO"), in California for the California Independent System Operator ("CAISO"), and in Texas for the Electric Reliability Council of Texas ("ERCOT"). To determine the steps and timeline undertaken to create these ISOs, the Project Team assessed publicly available information about each entity, including their websites and docket proceedings.

5.4.2 Steps and Timeline Necessary for Creation of an IGO

The steps and timeline necessary for the creation of an IGO vary among the jurisdictions that have ISOs. Because ISOs are nonprofit organizations, they are typically created either voluntarily by the utility companies, as was the case for NYISO and ERCOT, or have also been created by the state legislature, as CAISO was. Notably, the process for creating an ISO appears to occur outside of the typical docket process that was so integral for the other regulatory changes considered in this report. The following sections explain the steps and timelines used to create NYISO, CAISO, and ERCOT.

5.4.2.1 NYISO

The New York Independent System Operator ("NYISO") is a not-for-profit, independent company that is led by an independent Board of Directors. The company is unaffiliated with any state or federal agency or energy company and is responsible for operating the state's bulk electricity grid, administering the state's competitive wholesale electricity markets, conducting comprehensive long-term planning for the state's electric power system, and advancing the technological infrastructure of the electric system serving the state.[258] The NYISO performs these

[258] FERC, New York Independent System Operator, https://www.ferc.gov/industries/electric/indus-act/rto/metrics/nyiso-rto-metrics.pdf, at 197

duties under the strict regulatory oversight of FERC, NERC, the New York State Reliability Council ("NYSRC"), the Northeast Power Coordinating Council ("NPCC"), and the PSC.[259]

The NYISO as it exists today evolved from a much older entity, the New York Power Pool ("NYPP"). The NYPP was created voluntarily by the State's investor-owned utility companies following the Northeast Blackout of 1965 in order to coordinate the reliable operation of the respective power systems by managing energy supply and demand, transmission voltage, system contingencies, operating reserves, and dispatched generation.[260] The NYPP later included NYPA in 1967[261] and continued its operations until 1997, when it filed a proposal with FERC to form an Independent System Operator. This occurred as the PSC was restructuring the New York market to increase competition. The proposal was approved in 1998, and the NYISO officially began its operations and control of the New York electric power system on December 1, 1999. Participants in New York's wholesale electricity markets pay a small surcharge which covers the costs to run the NYISO.[262]

Summary of steps taken to create the NYISO: The NYPP was created by the utility companies to manage the grid reliability in response to the Northeast Blackout of 1965. The NYPP operated for more than thirty years. Then, following the deregulation of the New York market and the initiative of FERC to authorize ISOs, the NYPP applied to FERC to become an ISO. The time between NYPP's application to FERC and the beginning of official operations as an ISO was about 2 years.[263]

5.4.2.2 CAISO

The California Independent System Operator ("CAISO") provides "open and non-discriminatory access to the bulk of the state's whole transmission grid [and a small part of Nevada's grid], supported by a competitive energy market and comprehensive infrastructure planning

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[259] NYISO, Who We Are, accessed Sept. 25, 2018, https://home.nyiso.com/who-we-are/

[260] New York Independent System Operator, Inc., NYISO Agreements, August 8, 2012, available at: http://www.nyiso.com/public/webdocs/markets_operations/documents/Legal_and_Regulatory/Agreements/NYISO/nyiso_to_agreement.pdf, which states "Whereas, the Investor-Owned Transmission Owners established the New York Power Pool ("NYPP") by agreement made as of this 21st day of July, 1966,…"

[261] Eric Anderson, 50 Years Ago Albany Went Dark in the Great Northeast Blackout, Times Union, Nov.12, 2015. https://www.timesunion.com/tuplus-business/article/50-years-ago-mdash-Albany-went-dark-in-the-6616751.php

[262] NYISO, Frequently Asked Questions, accessed Sept. 25, 2018, https://home.nyiso.com/faq/ ; FERC, 2010 RTO/ISO Metrics Report: NYISO, https://www.ferc.gov/industries/electric/indus-act/rto/metrics/nyiso-rto-metrics.pdf

[263] New York Independent System Operator, Introduction to the NYISO, July 21, 2011, available at: http://www.nyiso.com/public/webdocs/markets_operations/committees/councils/consumer_advisory_council/Introduction_to_the_NYISO.pdf at 3.

efforts."[264] The CAISO is a nonprofit public benefit corporation that was created by the California Legislature in Assembly Bill 1890 in 1996.[265] The bill was designed in response to the passage of the federal Energy Policy Act of 1992,[266] and caused the restructuring of the state's power market. The CAISO was incorporated in May 1997 and began operations, including managing the state's transmission grid, facilitating the spot market for power and performing transmission planning functions, in March 1998.[267]

In addition to the fact that the CAISO was created by the state legislature, the CAISO is also unique from other ISOs assessed in this report in the composition of its board of directors. Whereas ISOs typically are led by a board of directors comprised of independent members, the CAISO's board is appointed by the state.[268] To transfer control of transmission facilities to the CAISO and implement the restructuring envisioned by the legislation, the three largest investor-owned electric utilities in California filed a joint application with FERC to transfer control of

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[264] California ISO, "About Us," accessed Sept. 24, 2018, http://www.caiso.com/about/Pages/default.aspx

[265] California Assembly Bill No. 1890, September 23, 1996 (Stats. 1996, c. 854 (A.B. 1890), § 10, eff. Sept. 24, 1996) (codified in part, e.g., as West's Ann. Cal. Publ. Util. Code § 330).

> 1(c) It is the intent of the Legislature to direct the creation of a proposed new market structure featuring two state chartered, nonprofit market institutions; a Power Exchange charged with providing an efficient, competitive auction to meet electricity loads of exchange customers, open on a nondiscriminatory basis to all electricity providers; and an Independent System Operator with centralized control of the statewide transmission system. A five-member Oversight Board comprised of three gubernatorial appointees, an appointee of the Senate Committee on Rules and an appointee of the Speaker of the Assembly will oversee the two new institutions and appoint governing boards that are broadly representative of California electricity users and providers. A.B. 1890
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> The legislature found that the "commission has properly concluded that (1) this competition will best be introduced by the creation of an Independent System Operator and an independent Power Exchange."

[266] The Energy Policy Act of 1992 was designed to decrease the country's dependence on imported energy, promote energy conservation, and provide incentives for clean and renewable energy. 102nd Congress H.R. 776 ENR.

[267] FERC, "California Independent System Operator Corporation (California ISO)," https://www.ferc.gov/industries/electric/indus-act/rto/metrics/caiso-rto-metrics.pdf

[268] California Assembly Bill No. 1890, September 23, 1996. Notably, the formation and method of formation of this unique board of directors was the subject of judicial review. Ultimately, the court ruled FERC did not have the authority to enforce their order to restructure the board of directors to be more aligned with ISO requirements. The court continued, reasoning that if FERC did not approve, it could remove CAISO's ISO status, but could not compel them to amend their practices as a separate order.

> "FERC has the authority not to accept something which it does not deem an ISO. It does not have the authority to reform and regulate the governing body of a public utility under the theory that corporate governance constitutes a "practice" for ratemaking authority purposes."
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> *California Independent System Operator Corporation v. FERC*, 372 F.3d 395, 404 (DC Cir. 2004).

transmission facilities to CAISO and to sell electricity to the Power Exchange.[269] Because California's grid includes interstate transmission lines, CAISO is subject to FERC regulation.

Summary of steps taken to create the CAISO: To create the ISO, California wrote and passed legislation through the state legislature, and then implemented the requirements in the legislation, including assigning a board of directors, and transferring control of the transmission facilities to the ISO via FERC application, which was required because California is subject to FERC's jurisdiction. This process took about two years to complete.

5.4.2.3 ERCOT

The Electric Reliability Council of Texas ("ERCOT") is the ISO for the Texas region and manages power on the electric grid for about 90 percent of the state's electric load.[270] More specifically, ERCOT's primary tasks include scheduling the power on the grid, performing financial settlement for the competitive wholesale bulk-power market, and administers retail switching for seven million premises in competitive choice areas.[271] ERCOT is a membership-based 501(c)(4) nonprofit corporation whose members include "consumers, cooperatives, generators, power marketers, retail electric providers, investor-owned electric utilities, transmission and distribution power providers and municipally owned utilities."[272] ERCOT is governed by an independent board of directors and subject to oversight by the Texas PUC and the Texas Legislature.[273] Notably, although ERCOT is an ISO, the ERCOT grid is generally not subject to FERC regulation due to its insulation within the State of Texas and lack of interstate transmission lines. Due to its independence from federal regulation, ERCOT was created by the state and did not need FERC approval for its creation and is not subject to FERC oversight for regulatory

[269] Pacific Gas & Electric Co., 77 FERC ¶ 61,204 (1996).

[270] ERCOT, "About" accessed Sept. 28, 2018, http://www.ercot.com/about

[271] ERCOT Quick Facts, Aug. 8, 2018, http://www.ercot.com/content/wcm/lists/144926/ERCOT_Quick_Facts_8818.pdf

[272] ERCOT, "About" accessed Sept. 28, 2018, http://www.ercot.com/about

[273] *Id.*

changes.[274] The Texas PUC confirms this, stating that ERCOT is "[t]he only ISO created under state law, not by FERC."[275]

ERCOT's predecessor, the Texas Interconnect System ("TIS"), was created in 1941 by several electric utilities that joined together to support the war effort by sending excess power supplies across Texas to the Gulf Coast for aluminum smelting activities. Their war effort demonstrated to the companies the benefits of interconnection for reliability, and they continued to use and develop the interconnected grid into the future. Decades later, following the new NERC requirements that arose following the Northeast Blackout of 1965, TIS formed ERCOT to comply with NERC requirements,[276] although TIS still operated as its own, large entity until 1981, when it transferred all operating functions to ERCOT. During the 1990s, amid local and national support for deregulation of electricity markets, ERCOT's role grew. In 1995, the Texas Legislature voted to deregulate wholesale generation, and the Texas PUC began to expand ERCOT's responsibilities to include and enable wholesale competition and efficient use of the power grid for all market participants. On August 21, 1996, the Texas PUC endorsed an electric utility joint task force recommendation that ERCOT become an ISO, and on September 11, the ERCOT Board restructured the entity as a nonprofit ISO and became the first ISO in the country. Since then, ERCOT has continued to function as an ISO for the State of Texas.[277]

Summary of steps taken to create the ERCOT: To create the ERCOT ISO, Texas utilities first voluntarily created a reliability organization that encouraged and oversaw the interconnection of

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[274] See FERC, "ERCOT," https://www.ferc.gov/industries/electric/indus-act/rto/ercot.asp

See also: "FERC has limited jurisdiction over ERCOT because the ERCOT system is isolated from the rest of the nation's power grid with the exception of two non-synchronous interconnections. s. Under Section 201(b)(1) of the Federal Power Act, the Commission does not have jurisdiction over facilities used for the generation of electric energy, or over facilities used in the local distribution or only for the transmission of electric energy in intrastate commerce except as provided in other portions of the Act. One exception is provided in Section 201(b)(2) of the FPA, which provides that the Commission does have jurisdiction over the connection of co-generation facilities to the grid under Section 210 and over wheeling between utilities under Sections 211 and 212 without regard to the limitations of Section 201(b)(1). The Commission also has jurisdiction over the two interconnects between ERCOT and the adjoining grid based on a settlement under Section 211. The Commission also has limited jurisdiction over assets of holding companies that own facilities in ERCOT and outside ERCOT, and as such are subject to the Public Utility Company Holding Act of 1935 for purposes of mergers, consolidations, and the competitive aspects of corporate control. However, the Commission does not have the comprehensive jurisdiction over the ERCOT transmission grid that it does over transmission grids located in other parts of the country."
FERC, Investigation of Bulk Power Markets, ERCOT (Texas), Nov. 1, 2000, available at https://www.ferc.gov/legal/maj-ord-reg/land-docs/ercot.PDF at 4-1.

[275] Tom Hunter, Public Utility Commissioner of Texas, History of Electric Deregulation in Texas, Electric and Gas Reliability Workshop, April 17, 2012, available at https://www.puc.texas.gov/agency/topic_files/101/PUC-History_Dereg_ERCOT.pdf

[276] Recall that NERC's jurisdiction includes users, owners, and operators of the bulk power system for North America. NERC, "About NERC," accessed Sept. 28, 2018, https://www.nerc.com/AboutNERC/Pages/default.aspx .

[277] ERCOT, "History," http://www.ercot.com/about/profile/history .

the electrical grid within Texas. Over time, this organization adapted to accommodate changes in the market including deregulations and finally became a non-profit, independent entity that qualified as an ISO. The time from when the Texas legislature and PUC decided to expand ERCOT's role to become an ISO to when it became an ISO was less than 2 years.

5.4.2.4 Additional Considerations for Hawaii Steps and Timeline

Although the publicly available information for the above ISOs provided relatively straightforward methodologies for creating their ISOs, the Project Team anticipates that additional steps may be required for some methods that the state of Hawaii may pursue to create its IGO. This is based on an assessment of comparable initiatives undertaken in Hawaii, that are discussed in Section 5.4.5.1, below. In sum, the additional steps are likely to include an investigatory proceeding into the creation of an IGO, the results of which will inform action by the state legislature. This general process has been detailed in sections 4.3 and 5.2.4, above.

5.4.3 Transition Costs of Creating an IGO

The costs of forming and managing an IGO may be estimated based on the long history of such entities in the mainland US. However, as with other regulatory models, there is substantial uncertainty in scaling these costs to Hawaii as all existing examples of the IGO model cover significantly larger service areas than a potential Hawaii IGO. A critical issue in the estimation of IGO transition costs in Hawaii will be the degree to which implementation costs may be scaled down to reflect the smaller size of Hawaii's grid.

5.4.3.1 Transition and Operational Costs of Mainland IGOs

The Project Team's assessment of potential IGO transition costs is based on analysis previously conducted by the FERC on the investment outlay and annual operating costs of RTOs in the United States.[278]

At the time, FERC staff noted that investment requirements for new RTOs had ranged from $38 million to $116 million ($51 million to $157 million in 2018 dollars), and annual operational costs had ranged from $35 million to $78 million ($47 million to $105 million in 2018 dollars). FERC projected that new entities would benefit from the lessons learned of existing organizations and be able to implement a new RTO with both initial investment costs and annual operating costs falling in the range of $50 million to $70 million ($67 million to $94 million in 2018 dollars).

FERC also projected these costs on a $/kWh basis, noting a median cost of $0.2 per MWh ($0.27/MWh in 2018 dollars) in existing RTOs, equivalent to an average rate impact of 0.3%. However, FERC noted that $/kWh prices are sensitive to the overall size of jurisdiction, and

[278] FERC Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization, Docket No. PL04-15-000. October 2004.

provided a separate estimate for smaller jurisdictions of $0.5 per MWh (or $0.67/MWh in 2018 dollars).[279]

5.4.3.2 Estimate of Operational Costs in Hawaii

The degree to which IGO costs are fixed or scalable with jurisdiction size is uncertain. If IGO costs are completely fixed and not responsive to jurisdiction size, we would expect the lower end of the cost range provided by FERC ($67 million in start-up costs and the same amount in operational costs each year, in 2018 dollars) to apply to Hawaii. However, if IGO costs may be scaled based on the size and complexity of a jurisdiction, Hawaii may experience a much lower IGO implementation cost. Based on the "small jurisdiction" per-MWh cost identified by FERC, and the Project Team's forecast of 11.9 TWh in annual electricity sales in Hawaii, this would yield both a start-up cost and an annual operational cost of $8.0 million. This wide range in potential reflects the uncertainty and many possible implementation pathways of a potential IGO model in Hawaii.

5.4.4 Conclusions on Steps and Costs of Creating and Operating an IGO

Although existing ISOs are quite different in situation and scale from any potential IGO in Hawaii, it is clear that an ISO or IGO is created as a separate entity purposed with managing the dispatch and planning functions of both the transmission and distribution assets on the grid. Based on the processes undertaken to create other ISOs on the US mainland, the Project Team concludes that in order to develop an IGO, the HECO Companies and KIUC must voluntarily agree to create a separate entity that would function as the IGO, or the state would need to compel the creation of the IGO through legislation. If the legislation is sought by the PUC, it is likely that the PUC would conduct an investigatory proceeding prior to working with legislators to draft a bill. Following the creation of the entity, the utilities would have to turn over transmission operations to the IGO. Due to Hawaii's exclusion from FERC jurisdiction of interstate transmission (among other things), Hawaii's IGO would not need to file tariffs or otherwise apply to become an ISO with FERC.[280]

In terms of timeline, the process of creating an ISO dated from the initial decision to create an IGO to its initial operation takes approximately one-and-a-half to two years.[281] This timeline was

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[279] However, as noted in the discussion of HERA costs, the size of FERC's "small" jurisdiction is still approximately 10 times higher than Hawaii's electric grid.

[280] Precedent for this comes from ERCOT, which similarly is excluded from FERC's jurisdiction. ERCOT became an ISO at the direction of the state, not FERC. *See* Tom Hunter, History of Electric Regulation in ERCOT, Public Utility Commission of Texas, April 17, 2012, https://www.puc.texas.gov/agency/topic_files/101/PUC-History_Dereg_ERCOT.pdf at 10.

[281] See, ERCOT, "History," http://www.ercot.com/about/profile/history; and Texas Legislature Online, "history," https://capitol.texas.gov/billlookup/History.aspx?LegSess=74R&Bill=SB373, which indicates that in June 1995 the Texas legislature voted to deregulate the wholesale generation system and began the process of expanding ERCOT's responsibilities. Then on August 21, 1996, ERCOT became the first ISO in the United States. See also, New York Independent System Operator, Introduction to the NYISO, July 21, 2011, available

generally consistent among the jurisdictions considered in this report, even when circumstances varied. For example, in New York and Texas, this timeline may have been affected by the fact that the ISO responsibilities and title were assigned to existing entities that already performed many of the same functions, whereas in California, legislation created a brand-new entity. All three jurisdictions are quite large and contain at least several utility companies.

Despite this clear trend in timelines for creation of an IGO, when contemplating establishing an IGO in Hawaii, it is also important to note any factors that may cause the timeline to vary. Specifically, it will be essential to consider the fact that there is no existing entity that could assume the responsibilities of the IGO and thus, a new entity will be required. Additionally, the size of the transmission grid and the number of utilities involved in Hawaii are much smaller than in other jurisdictions. Either of these considerations could cause the timeline to be slightly longer or shorter than two years in duration.

Costs were difficult to predict based on the difference in size and scalability of a national model to a single jurisdiction, and in particular, one as small as Hawaii. However, the Project Team estimates that it would cost at least $8.0 million to start-up an IGO in Hawaii (and the same amount in annual operational costs) based on a comparison to the costs of similar (but larger) organizations on the mainland.

5.4.5 Legal Considerations for an IGO

Based on the assessment of several existing ISOs above, it seems clear that the ISO or IGO can either be created voluntarily by the utility companies or by the state through legislation. The utility companies in New York and Texas voluntarily created the predecessor entities to their ISOs in response to some extraordinary event. In New York, the utilities created the NYPP after realizing the importance of an interconnected grid following the Northeast Blackout of 1965. In Texas, the utilities came to a similar realization after their efforts to support the country during World War II. Then, during the deregulation of the energy market in the late 1990s, New York created NYISO as a method of complying with FERC Order 888.

In contrast, Texas adjusted the corporate structure and purpose of ERCOT to be an ISO on its own initiative. Since Texas is not part of FERC's jurisdiction for this purpose, ERCOT became Texas' ISO through initiatives of the state and was not subject to FERC approval. California's ISO was created by the legislature and, like NYISO and other ISOs besides ERCOT, was submitted to FERC

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at: http://www.nyiso.com/public/webdocs/markets_operations/committees/councils/consumer_advisory_council/Introduction_to_the_NYISO.pdf at 3, showing timeline in which NYPP files NYISO proposal in 1997, and NYISO begins operations on Dec. 1, 1999. Finally, see, FERC, "California Independent System Operator Corporation (California ISO)," https://www.ferc.gov/industries/electric/indus-act/rto/metrics/caiso-rto-metrics.pdf, and California Assembly Bill No. 1890, September 23, 1996 (Stats. 1996, c. 854 (A.B. 1890), § 10, eff. Sept. 24, 1996) (codified in part, e.g., as West's Ann. Cal. Publ. Util. Code § 330).which show that CAISO began full transmission operations in March 1998, about 1.5 years after CAISO was created in September 1996.

as compliance for FERC Order 888. Unlike NYISO, CAISO is influenced by the state (rather than being independent) in its operations.

Hawaii's situation is quite different from New York, California and most other states because its grid is not connected to the grid of any other state and therefore does not engage in interstate transmission. In this way, it is similar to ERCOT because the grid isolation excludes Hawaii from FERC regulation of electricity transmission. Hawaii's situation is also different from the other jurisdictions because the state has so few utility companies in its jurisdiction. Aside from KIUC on the island of Kauai, Hawaii's grid is primarily owned by one utility company (HECO, HELCO, and MECO are all subsidiaries of Hawaiian Electric Industries). Therefore, it seems unlikely that the HECO Companies would voluntarily create a separate entity to manage fairness and grid operations when it currently is the exclusive owner of the grid on all islands except Kauai. Additionally, it seems unlikely that the HECO companies would voluntarily give up transmission responsibilities. Based on these assumptions, the Project Team focuses this legal analysis on the State's authority to create an IGO entity.

5.4.5.1 State of Hawaii's Authority to Create an IGO

Hawaii does not currently have an existing legal framework for the IGO regulatory model. As was discussed in Section 4.3.3, state law grants the PUC broad supervisory and investigative authority, which it could use to initiate proceedings related to IGO issues. Additionally, as discussed in Section 5.2.7, the PUC also has the authority to create HERA, which could perform some of the reliability functions that the IGO would perform. Thus, although the PUC would likely have the power to implement some components of the IGO model through its current general supervision, investigation, and ratemaking authority, legislation may be needed to clarify the PUC's authority over the new IGO entity, and as a practical matter, to encourage the PUC to proceed with this course of action if it is deemed in the best interest of Hawaii.

In light of the above considerations, the Project Team has identified several paths the State of Hawaii could take to establish an IGO based on past experiences by the State. Each of these pathways require legislation, and it is unlikely that any of the paths or legislation will create an entity that is truly independent of state influence. However, complete independence of the IGO in Hawaii may not be problematic. While the ISO standard of FERC lists independence as a critical element of the ISO, it is true that both the Texas ISO and the California ISO are influenced by their States. As was discussed above, CAISO was created by the California legislature and its board is appointed by the governor. Although FERC theoretically could revoke CAISO's ISO status for failure to comply with the ISO standards, it hasn't done so yet.[282] In Texas, ERCOT is regulated by the Texas Legislature and the Texas PUC, and this is acceptable because ERCOT is not subject to FERC regulation for these matters. Because Hawaii is also not subject to FERC regulations, the matters of strict independence of the IGO are likely less important from a legal standpoint as they

[282] "FERC has the authority not to accept something which it does not deem an ISO. It does not have the authority to reform and regulate the governing body of a public utility under the theory that corporate governance constitutes a "practice" for ratemaking authority purposes." *California Independent System Operator Corporation v. FERC*, 372 F.3d 395, 404 (DC Cir. 2004)

are in FERC regulated jurisdictions. However, the IGO created will be subject to PUC regulation, and presumably, the PUC will help to keep the IGO independent to the extent necessary for the IGO to accomplish its duties.

5.4.5.1.1 Reapportion utility transmission fees to third-party administrator

One method the state could use to create an IGO is to reapportion utility transmission fees currently paid to the utilities to a third-party administrator that would be contracted by the PUC. The third-party administrator could effectively be the IGO, with funds directed to support the fair and independent management of the transmission grid.

The precedent for this strategy comes from the Public Benefits Fee law,[283] which arose from the Consumer Advocates recommendation for such an initiative and third-party administrator in HECO's demand-side management and energy efficiency proceeding (Docket No. 05-0069).[284] The law was first legislated in 2006 and refined in the 2008 session. The law gave the PUC the authority to change the market structure of energy efficiency programs by appointing a third-party administrator to implement the energy efficiency programs. This adjusted design was an attempt to "remove the perceived inherent conflict between a utility's desire to generate revenues and income, and energy efficiency measures that serve to decrease sales and defer the need for additional plant investment" and also was intended to provide better facilitation of those programs at a greater cost efficiency.[285] The third party administrator would be funded by the Public Benefits Fee (or Public Benefits Fund) that itself was funded by an energy bill surcharge.[286]

The third party administrator would be chosen by and respond to the PUC but is not deeded a "governmental body" so long as the fees collected by the administrator were comprised solely of the public benefit fees under the statute.[287] Following the initial creation of this law, the PUC opened an investigative docket "to examine the issues and requirements raised by, and contained in, Part VII of Chapter 269, Sections 269-121, et seq., HRS about Hawaii's Public Benefits Fund."[288]

Additionally, the docket sought to use the proceeding to select a Public Benefits Fund Administrator and implement a new market structure for Energy Efficiency Demand-Side

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[283] Haw. Rev. Stat. §§ 269-121-125.

[284] About the Division of Consumer Advocacy, 2007, http://www.hawaiienergypolicy.hawaii.edu/outreach-communication/legislative-briefings/_downloads/2007-division-consumer-advocacy-awakuni.pdf at 5

[285] Chris Ann Dickerson et al., Aloha E Komo Mai: Hawaii Introduces its New Energy Efficiency Program Structure (ACEEE 2010), available at https://aceee.org/files/proceedings/2010/data/papers/2077.pdf at 54-55, quoting the bill (original text of the act including its purpose was not available online).

[286] Haw. Rev. Stat. § 269-121

[287] Haw. Rev. Stat. § 269-122

[288] Hawaii Public Utilities Commission, Order No. 23681, Docket No. 2007-0323, issued September 26, 2007.

Management.[289] In 2009, Leidos, then known as Science Applications International Corporation ("SAIC"), was awarded the contract with the PUC to be the program administrator of Hawaii's energy efficiency programs.[290] The docket is still open as the means to set the public benefits fee budget and fee surcharges.

This particular method to create a new entity appears to be a good fit for creating an ISO because it also removed a responsibility from the utilities and created a new funding mechanism and entity to overtake that responsibility. Although the PUC was involved in the implementation and regulation of the third-party administrator, it is technically considered a non-government body. Based on the success of this program, it is reasonable to conclude that the PUC and the legislature could take a similar approach to divesting the utilities of transmission and distribution management operations.

5.4.5.1.2 Creation of a new agency, corporation, or instrumentality of the State

Another method the state could use to create an IGO is to establish a new state agency or instrumentality of the state via legislation. A good example of this is the Hawaii Green Infrastructure Authority ("HGIA"). HGIA and the Hawaii green infrastructure loan program were created in the 2013 Hawaii Laws Act 211, which was codified as HRS §196-61 et seq. The purpose of the act was to "establish a regulatory financing structure that authorizes the [PUC] and [DBEDT] to acquire and provide alternative low-cost financing, to be deployed through a financing program to make green infrastructure installations accessible and affordable for Hawaii's consumers, achieve measurable cost savings, and achieve Hawaii's clean energy goals."[291]

For administrative purposes, HGIA is within DBEDT and is "an instrumentality of the State comprising of five members. More specifically,

> *The director, the director of finance, and the energy program administrator of the department shall be members of the authority. The governor shall appoint the other two members, pursuant to section 26–34. The director shall be the chairperson of the authority. The authority shall be placed within the department for administrative purposes, pursuant*

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[289] *Id.*

[290] In 2012, SAIC split into two companies. SAIC spun off into its own company, and the parent company rebranded itself as Leidos. https://www.washingtonpost.com/business/capitalbusiness/one-year-later-saic-and-leidos/2014/09/26/d1fefd68-4273-11e4-b437-1a7368204804_story.html?noredirect=on&utm_term=.8c2d57f8b7fa

Leidos has continued to operate the Hawaii Energy Program, most recently securing another potential nine-year contract in 2016. https://blog.executivebiz.com/2016/07/leidos-awarded-85m-hawaii-energy-conservation-program-mgmt-extension/

[291] Hawaii Session Laws, Act 211, June 27, 2013 (S.B. 1087 CD1), available at: https://www.capitol.hawaii.gov/session2013/bills/SB1087_CD1_.htm

to section 26–35; provided that until the authority is duly constituted, the department may exercise all powers reserved to the authority and shall perform all responsibilities of the authority. [292]

The program operations are funded by revenue bonds issued by DBEDT, while the bonds issued by GEMS are paid for by a PUC-approved Green Infrastructure Fee on utility bills.[293] The HGIA developed and operated the green infrastructure financing program, known as GEMS,[294] which was designed to make clean energy improvements affordable and accessible for a broader cross-section of Hawaii ratepayers. Although the HGIA and the GEMS program operate within DBEDT for administrative purposes and are subject to PUC approval,[295] they were created for a specific purpose and effectively operated as a separate entity.

The creation of the HGIA and GEMS program illustration another method by which the state was able to adjust the regulatory process by creating a new entity. As with the previous example, this method has been successfully[296] implemented in Hawaii, indicating the existence of legal authority for a similar effort in terms of creating an IGO. Additionally, due to Hawaii's independence from FERC regulation, the Project Team anticipates that state interaction with the IGO will not be problematic, although less interference would likely result in a more effective IGO.

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[292] Haw. Rev. Stat. 196-63

[293] GEMS, FAQs, http://gems.hawaii.gov/learn-more/faqs/

[294] GEMS stands for Green Energy Market Securitization Program. *Id.*

[295] The HGIA/GEMS public filings, including the approval of the GEMS program and annual plan approvals, are contained in Docket No. 2014-0135.

[296] The Project Team notes that success here refers explicitly to the implementation process.

6 Conclusion on Steps, Timeline, Costs, and Legal Framework

This report has explored the steps, timelines, costs, and legal considerations required for the implementation of the various elements of the three regulatory models proposed for the State of Hawaii. This section of the report brings the elements together under each proposed regulatory model, to provide an overview of the steps, timeline, costs, and legal considerations required for each regulatory model. Following the summary of each regulatory model, this section highlights some of the key considerations in concluding thoughts.

6.1 Summary of the Steps, Timeline, Costs, and Legal Framework for Each Model Considered

In Task 2.2.6, the Project Team identified three regulatory models for further consideration in this analysis. These regulatory models were (1) Outcomes-based PBR; (2) Conventional PBR with Light HERA; and (3) a Hybrid Model that included a combination of Outcomes-based PBR with DSPP and an IGO. This report considered the various elements of each regulatory model separately due to the presentation of and availability of resources for comparison, but now assesses each model as a sum of its component parts.

6.1.1 Outcomes-based PBR

Based on the estimates included in Sections 4.1 and 5.1, above, Hawaii's timeline for implementing Outcomes-based PBR would still be 21 months dated from the Order initiating an investigative docket on PBR to the legislature's January 1, 2020 deadline to implement PBR as the regulatory model for the state. It is feasible for Hawaii to meet this 21-month timeline, particularly if the PUC is able to efficiently and effectively design a review and approval process for utility companies' PBR plans that builds upon the existing PBR mechanisms. However, it should be anticipated that the PUC may require additional time to fully implement the new regulatory model. This is particularly true if the PUC were to implement a more complex Outcomes-based PBR model. If the design of specific mechanisms or the process of working with stakeholders and utility companies run into any challenges or delays, which is quite likely for such a complex model (especially in its first iteration), the timeline for the ultimate transition could be delayed, extending beyond 21 months.

The specific steps and timeline for implementing an Outcomes-based PBR model in Hawaii are likely to be similar to the steps and timeline used for PBR in general.[297] Again, although this process has taken up to approximately 30 months in RIIO, the process could be shortened through political will and efficiency and use of simpler mechanisms (especially during the first generation PBR), or could be lengthened depending on the depth and complexity of the Outcomes-based PBR model that is chosen.

During the course of 21 months, the PUC generally should 1) state its intent to transition to PBR and release a schedule, 2) engage in Stakeholder education and outreach, 3) publish the guiding

[297] See Section 4.1, supra.

principles to be used and the stakeholder feedback already procured, 4) finalize the PBR guiding principles and framework, 5) commence an independent study to help develop specific mechanisms and PBR components, 6) conclude and submit results of the independent study, 7) require utilities and other interested parties to submit their PBR proposals, 8) admit intervenors, respond to information requests, conduct oral hearings and receive submitted arguments by utilities and other intervenors, and 9) issue a final PBR decision.[298] This process also broadly reflects the process proposed and begun by the PUC.

Costs of implementation are calculated within a range that is based on the overall cost increase experienced by the AUC in its three-year transition, and one based on the percentage change (10.9%) in costs. This approach yields an effected range in the estimated cost impact of between $683,000 and $2.78 million (in 2018 USD) per year over a three-year transition period. This results in a total transition cost of between $2.0 million and $8.3 million. The Project Team also anticipates costs to return to pre-transition levels following the transition, even during the implementation of subsequent PBR terms.[299]

The legal requirements for Outcomes-based PBR are satisfied with the existing legal framework.[300]

6.1.2 Conventional PBR + Light HERA

The steps and timeline for implementing Conventional PBR + Light HERA require a combination of the steps and timeline contemplated for PBR in general and HERA.

The Conventional PBR process is also represented by the general PBR process, described in Section 4.1.3. During the course of 21 months , the PUC should follow the 9 steps listed in Section 6.1.1, above. At the time of this writing, the PUC is in step 3 of this process, having held two technical workshops and has begun receiving regulatory assessment briefs from the parties.

In addition, the PUC will have to open a docket to investigate the design of and eventually implement HERA. Based on other investigative dockets in the PUC, this process may take approximately 2 years to complete and involves 1) opening the docket, 2) conducting the docket proceedings (e.g., motions to intervene, motions for additional information, briefs from the parties and intervenors), 3) issuing the decision and order regarding conclusions on the docket, and potentially 4) address any outstanding issues set forth in the decision and order.

Ideally, the PUC would conduct both processes simultaneously, so that the full implementation of this proposed model would occur within the longer PBR timeline of 33 months. If the PUC

[298] See Section 4.1.3, supra.

[299] See Section 4.2.3, supra.

[300] See Section 4.3, supra

were to conclude its PBR proceedings before initiating the HERA docket, the entire process would take close to five years for full implementation of the model.

Costs to implement the Conventional PBR + Light HERA model involves the combination of costs anticipated for both PBR and HERA. Costs of implementation for Conventional PBR follow the costs for general PBR and includes an effected range in the estimated cost impact of between $683,000 and $2.78 million (in 2018 USD) per year over a three-year transition period. This results in a total transition cost of between $2.0 million and $8.3 million. The Project Team also anticipates costs to return to pre-transition levels following the transition, even during the implementation of subsequent PBR terms.[301] In addition, the Project Team estimated of the HERA model based on the funding requirements of NERC, a similar entity active in mainland North America. Based on a per-kWh scaling of organizational costs, HERA would require a start-up cost between $234,000 and $585,000, and between $480,000 and $1.2 million in annual funding.

The legal requirements for Conventional PBR and HERA are both satisfied by the existing legal framework.[302]

6.1.3 Hybrid Model (Outcomes-based PBR + DSPP + IGO)

The steps and timeline for implementing the Hybrid Model require a combination of the steps and timeline contemplated for Outcomes-based PBR, a DSPP and an IGO. To reduce volatility from too many regulatory changes at once, the Project Team envisions a staggered implementation timeline, with the Outcomes-based PBR component being implemented in 2020, IGO established in 2023, and DSPP operations beginning in 2028.

During the course of the 21 months anticipated for Outcomes-based PBR to meet the January 1, 2020 deadline, the PUC will have to follow the steps detailed in Section 4.1.3 and summarized in Section 6.1.1, above. This process also broadly reflects the process proposed and begun by the PUC. The PUC would also need to operate with great efficiency and expediency and possibly choose simpler PBR mechanisms that would not require additional studies.

Costs of implementation are calculated within a range that is based on the overall cost increase experienced by the AUC in its three-year transition, and one based on the percentage change (10.9%) in costs. This approach yields an effected range in the estimated cost impact of between $683,000 and $2.78 million (in 2018 USD) per year over a three-year transition period. This results in a total transition cost of between $2.0 million and $8.3 million. The Project Team also anticipates costs to return to pre-transition levels following the transition, even during the implementation

[301] See Section 4.2.3, supra.

[302] See Section 4.3and Section 5.2.1, supra.

of subsequent PBR terms.[303] The legal requirements for Outcomes-based PBR satisfied by the existing legal framework.

Following the implementation of Outcomes-based PBR by January 1, 2020, the PUC and the legislature will need to work to create an IGO. This process would require writing and passing legislation authorizing the IGO, as well as a PUC docket to investigate the best design for an IGO and/or to function as a proceeding to regulate the IGO. This process of developing an operational IGO is estimated to take one-and-a-half to two years to complete. The costs are estimated to be at least $8.0 million in startup costs and the same amount in annual operation costs, based on a comparison to mainland organizations, though it is possible for costs to be substantially higher if organizational costs cannot be effectively streamlined to suit Hawaii's smaller geographic area. As mentioned above, new legislation will be required to create this entity, although there is a precedent for such legislation in Hawaii's legislative history.

After the IGO is operational (and perhaps before), the PUC would need to work on transitioning the utilities to assume the roles and responsibilities of DSPPs. This process, in particular, is very complex, time-consuming, and collaborative between all the parties, so it is helpful and more realistic for the implementation timeline to be set at 2028. The Project Team estimates using a relatively normal docket proceeding process to develop the DSPP, but notes that the proceeding will contain more participants, more issues to resolve, and greater complexity of creating and integrating the various mechanisms created. The Project Team estimates a timeline of approximately three years to have a policy and implementation plan for the DSPP developed, along with some mechanisms, at least. It is unclear how long the full implementation will take, although the Project Team anticipates that 2028 is an achievable target.

The costs for implementing the DSPP are estimated at $51.4 million, spread over three years (for an annual cost of $17.1 million in the three-year start-up period). Following this period, the Project Team estimates a $1 million annual operating cost. These figures are based on the costs and budgets of pilot projects currently active in New York State, but are subject to substantial uncertainty given the novelty of the DSPP model. The Project Team concludes that there is legal authority for the PUC to require the utilities to transition to include in their business models the DSPP model. However, due to the novel nature of this regulatory model and Hawaii's tendency to authorize or incentivize PUC actions via legislation, the Project Team recommends creating a statute that would explicitly authorize DSPP should this path be chosen.

6.2 Concluding Thoughts

The PUC has broad legal authority to implement regulatory changes that are in the public interest and that advance state energy goals. In particular, the PUC clearly has the legal authority to implement changes to the regulatory scheme that would result in both or either a PBR (outcomes-based and conventional) or HERA regulatory model. For PBR and especially HERA, this authority is supported by legislation explicitly requiring or authorizing each regulatory shift. The existing legal authority likely extends to the creation of a DSPP model, because such a shift would

[303] See Section 4.2.3, supra.

be an extension of normal regulatory operations. However, due to the novel nature of the DSPP model and the state's past precedence of creating legislation to support and explicitly authorize regulatory initiatives, the Project Team anticipates that such a regulatory change would likely require legislative support as a practical necessity if not a strict legal need. In contrast, the PUC does not appear to have the independent authority to implement an IGO. In the absence of voluntary utility-initiated efforts to create an IGO (which is unlikely), state efforts to establish an IGO would likely require state legislation similar to the processes undertaken to create ISOs in California and Texas.

In terms of timeline, the PUC is currently working under schedule to implement PBR by January 1, 2020. Based on a review of the timelines of similar past processes in other jurisdictions, the Project Team finds that this timeline is achievable if the PUC is able to manage the process with great efficiency and avoid some of the sources of delay that impacted regulatory shifts elsewhere. However, the Project Team anticipates that delay (of roughly up to one year, based on Alberta's timeline) may be necessary to provide the PUC with adequate time to fully consider the issues associated with the new regulatory model. The timeline to create the other elements of the regulatory models also require diligence but are not bound by a strict deadline as PBR is. The estimated timeline for HERA completion is approximately two years. The estimated timeline for legislating and creating an IGO is also approximately one-and-a-half to two. The DSPP model requires significant development of different regulatory mechanisms and interaction with the utility companies to develop the DSPP, so the timeline for implementation is likely to be much longer than the other models. In New York, the process has already taken approximately four years and still in progress. Although Hawaii probably would not take as long to implement DSPP due to its smaller grid size and fewer utility companies to work with, it is still likely to be a complex and time-consuming process that will take at least three years to complete.

Cost estimates are deeply uncertain, particularly for models such as DSPP and IGO, with a key factor being the size of Hawaii's grid. Many of the existing efforts to create these regulatory models have not been implemented on a grid size as small as Hawaii's, which makes the process of estimated transition costs inherently difficult and uncertain. Nevertheless, based on our analysis, the costs to establish the DSPP is $17.1 million during the three-year start-up period and $1 million in annual operating costs thereafter, while the costs to establish an IGO is between $8 million and $67 million in startup and annual operating costs, depending on the method of calculation. These cost calculations are discussed in detail in Sections 5.3.4.2 and 5.4.3.2, respectively.

7 Risk Analysis

The risks associated with the Status Quo regulatory model highlight some of the reasons why the State of Hawaii is considering a regulatory change. The COS regulatory model currently in use in the State of Hawaii provides a tacit incentive to the utilities to maximize shareholder returns by increasing the rate base and making capital investments. This incentive structure creates the risk of a negative impact on ratepayers, who may be required to pay higher rates based on the cost of increased capital investment. Thus, under this model, there is a clear tension between the interests of ratepayers and utility shareholders. The current regulatory approach also allows for some misalignment between state policy objectives and utility incentives, as the utility is not given a direct financial incentive to achieve state policy objectives (save for the limited use of performance incentives related to reliability and other factors). For example, the current regulatory approach offers limited financial incentives for utilities to pursue increased DER penetration.

Additionally, while ratepayers bear the burden of some critical risks in the short term (i.e., higher rates, impacts associated with failure to meet state energy goals), the utility shareholders may be exposed to dire risks such as grid defection in the long term. Grid defection is a particularly severe risk because it is nonlinear: as more customers leave the grid (likely due to the high costs or misalignment of incentives for them to stay on the grid), the higher the cost becomes for remaining customers. The higher costs for remaining customers then make grid defection seem more attractive and feasible to those remaining customers and compounds the grid defection. Although electricity usage is decoupled from utility revenues in the State of Hawaii, a dramatic decrease in the number of ratepayers that support large fixed costs is still likely to have serious negative repercussions for stakeholders. The alternative models proposed in this report offer potential solutions to the problems that arise from the continued use of the Status Quo. For instance, all the alternative models contain a form of PBR, which is purposefully designed to incentivize performance rather than capital investment. However, each of the alternative models come with their own risks, in part because of the additional complexity that they introduce into regulatory structures.

With this perspective, we assess and compare the various sources of financial and operational risks for different stakeholders (ratepayers and utility shareholders) under each regulatory model. During this exercise, we also assign a likelihood and risk impact rating for each risk under each regulatory model, and both the potential impact of the risk category and the likelihood of each risk are evaluated in tandem to assess the overall risk to the ratepayers and shareholders in each category. In our assessment of the potential impacts of the risks, we assess the risks in terms of how they may impact the issues that ratepayers care about (low-cost energy, reliability, access to renewables, etc.) and the issues that shareholders care about (returns and utility financial stability). This analysis does not attempt to score the total overall risk of each regulatory model, but instead identifies areas in which a particular regulatory model may have comparatively higher or lower degrees of risk than another.

Additionally, we note that this analysis primarily focuses on the risk categories as they relate to the HECO companies (particularly for shareholder risks, since the HECO companies are a traditional investor-owned utility). However, we do briefly discuss how KIUC could be impacted

by the risks, as applicable throughout the report. As KIUC is a cooperative utility, however, the Project Team does not make a distinction between ratepayers and shareholders.

7.1 Methodology

The Project Team has identified four regulatory models – Status Quo, Outcomes-based Performance-based Regulation ("PBR"), Conventional PBR with Light HERA, and a Hybrid Model that combines Outcomes-based PBR, a Distributed System Platform Provider ("DSPP") and an Independent Grid Operator ("IGO") – for further analysis, including this assessment of risks associated with the different models.[304] In addition, the Project Team applied the risk assessment to the regulatory model of Lighter PUC Regulation, although this scenario only applies to KIUC on Kauai, and is denoted with an asterisk in each table. Each model was assessed against a set of eight risk factors related to a series of regulatory, financial, and operational factors. For each risk category, we describe who is bearing the respective risk, and what can be done by different stakeholder groups (e.g., ratepayers, utility, regulators) to mitigate that risk. The final results are illustrated in an accompanying matrix, included in Figure 11. Note that the category "shareholder severity" is listed as "N/A" for all risk categories for the Lighter PUC Regulation for KIUC, as KIUC is a member-owned cooperative with no distinction between ratepayers and shareholders.

More specifically, for each regulatory model, all risk factors were assigned a qualitative risk rating and separate impact ratings for ratepayers and shareholders. The qualitative risk and impact rating schemes have five tiers: Low, Low-Medium, Medium, Medium-High, and High. In the tables for each regulatory model and the summary table of all the risks, the rating scheme is represented in the following way:

H – High Risk/Impact
MH – Medium/High Risk/Impact
M – Medium Risk/Impact
LM – Low/Medium Risk/Impact
L – Low Risk/Impact

Additionally, the risks were categorized by phase and type. The phase of the regulatory model distinguishes between risks that occur during the transition to an alternative regulatory model and the operation of the regulatory model. The type of impact highlights whether the risk impacts the utilities finances or their operations.

The actual risk rating reflects the relative *likelihood* that the risk factor could take place (i.e., the likelihood that the regulatory design would be more expensive than anticipated), while the impact rating reflects the relative *magnitude* the outcome would have on the utility if it took place (i.e., how impactful the extra, unanticipated expense of the regulatory model would be to the

[304] The recommended models for KIUC are (1) HERA, (2) IGO, and (3) lighter PUC regulation. These recommended models for KIUC are not the focus of this report, but discussed as applicable.

ratepayers and the shareholders). In some cases, but not all, the risks can be mitigated with various strategies.

7.2 Factor Results and Discussion

This section details the various risks projected for the implementation and operation of the regulatory models considered in this report. Specifically, each risk section first provides a summary table of the likelihood and magnitude of the risk across the four regulatory models and identifies the phase and type of risk being considered. Then the Project Team provides a discussion of the details of the risk as it applies to each regulatory model.

7.2.1 Cost and Complexity of Regulatory Approach

The following section discusses the risks related to the costs and complexity of the regulatory approach. These potential risks are important for the State of Hawaii to consider as it navigates the challenging task of choosing an appropriate regulatory model for the State's electric utilities to mitigate the larger risks of maintaining the Status Quo regulatory model. The complexity of the regulatory approach and the ability to accurately estimate costs have a great impact on whether the State would be able to implement a particular regulatory model or could afford to implement and operate it. This section aims to provide some guidance on this topic.

7.2.1.1 Regulatory Cost Risk

Model	Likelihood	Ratepayer Severity	Shareholder Severity
Status Quo	L	LM	L
Outcomes-based PBR	MH	MH	LM
Conventional PBR + Light HERA	M	M	LM
Hybrid Model	H	MH	LM
Lighter PUC Regulation*	LM	LM	N/A

Relevant Phase: Transition
Type: Financial

The potential Regulatory Cost Risk is the lack of clarity on the ultimate expense to the Commission or other actors of the implementation and ongoing use of alternative regulatory models, despite research and analysis into the subject. This uncertainty exists in particular because there is not an example of comparable size or market structure from which to draw conclusions for most regulatory alternatives. Whereas the State of Hawaii is a relatively small jurisdiction with a monopoly vertically integrated IOU provider that serves approximately 95% of the State's population and a cooperative on the Island of Kauai (serving the remaining ~5%), other jurisdictions that have implemented forms of the regulatory models considered in this report are considerably larger in size and consist of more than one or two utility companies. The inability to draw direct comparisons creates uncertainty in the ultimate costs of transitioning to alternative regulatory structures.

This potential risk is distributed differently across the four models. In the Status Quo model, there is a very low immediate regulatory cost risk because the model is currently in operation in the State of Hawaii. Therefore, the costs of transition are currently not necessary, and the costs of operation are well-known. However, it is possible that under the Status Quo model the issue of changing the regulatory model could be raised again in the future to improve the state's ability to meet its own goals. Because the regulatory cost risk is for the transitional phase, and because we use the Status Quo more as a base-level for reference in this report, for the purposes of this analysis we ascribe relatively little weight to such future potential events in this model, as described in Section 0, above. We assign a Medium-High likelihood that the transitional and operational costs will be more than anticipated for the Outcomes-based PBR model due to the complexity of the PBR model, and a Medium likelihood of the same for the Conventional PBR with Light HERA models. This is due to some uncertainties in the PBR model (noting that Conventional PBR is less complex than Outcomes-based PBR) combined with some uncertainty about whether Light HERA will incur implementation and operational costs and complexities without commensurate benefits. For the Hybrid model, there is a High likelihood that costs will be higher than anticipated due to the greater complexity of the model and its component parts (Outcomes-based PBR + DSPP + IGO) and the existence of fewer models with which to compare. The Project Team also considers the risks for this model to be the highest due to the uncertainty of DSPP revenues, as well as the novelty of the DSPP regulatory structure, which has not been fully implemented in any jurisdiction.

This analysis primarily considers uncertainty in the costs of regulating new models, and the Project Team assumes that the organizations that would incur these costs (such as the Hawaii PUC, HERA, or an IGO) would ultimately seek to recover any cost overruns from ratepayers. Therefore, the Project Team considers this risk category to be potentially more severe for ratepayers than for utility shareholders. During the transition to the alternative models, the Project Team anticipates a Medium-High level of severity of the risk to ratepayers under Outcomes-based PBR and Hybrid model, and Medium severity of risk to ratepayers under the Conventional PBR with Light HERA model (as the team expects the regulatory costs of these models to be more predictable). Meanwhile, we expect shareholders to be less affected by higher than anticipated costs, with Low-Medium rankings across the models. The differences in the severity of the risk on ratepayers versus shareholders is attributed to the fact that costs are more easily and more likely to be passed onto ratepayers than shareholders.

The potential Regulatory Cost Risk could be mitigated both by working to create cost forecasts from the best available data, as this report aims to do, as well as by closely managing costs as they arise to the extent possible.

While this analysis primarily concerns risks for counties served by the HECO Companies, similar risks may be expected in Kauai. The Project Team expects the IGO model to provide the greatest risk for cost uncertainty, as it a more complex model than HERA. Lighter PUC regulation would be expected to provide a net reduction in costs both for the PUC and for KIUC, though there is a risk that savings may not be as substantial as intended.

7.2.1.2 Regulatory Complexity Risk

Model	Likelihood	Ratepayer Severity	Shareholder Severity
Status Quo	L	M	M
Outcomes-based PBR	M	MH	M
Conventional PBR + Light HERA	M	MH	M
Hybrid Model	H	H	H
Lighter PUC Regulation*	L	L	N/A

Relevant Phase: Transition + Operation
Type: Operational

Any change in regulatory approach is subject to some degree of complexity, and in this case, each of the models assessed entails a greater degree of complexity than traditional COS regulation. This added complexity creates a potential risk for ratepayers and shareholders alike because as complexity in regulatory models increases, so does the likelihood for unintended consequences. As with Regulatory Cost Risk, Regulatory Complexity Risk exists in part because of the unavailability of an example of comparable size or market structure against which to compare to the State of Hawaii's regulatory scene. The inability to draw direct comparisons creates uncertainty in our assessment of the ultimate difficulty of the process to design and implement the alternative models and to operate them.

The potential risk of Regulatory Complexity varies across the different regulatory models considered. In the Status Quo model, there is Low regulatory complexity risk – while the rate case process used to consider utility costs and set rates under the COS model is not without its difficulties, these complexities are known and manageable in the State of Hawaii. We assign a Medium likelihood of risk for the Outcomes-based PBR and the Conventional PBR with Light HERA models. We consider Outcomes-based PBR to lead to substantially more complexity than the Conventional PBR model, due to the challenge of defining and tracking metrics that would inform the regulatory process. However, also incorporating HERA does increase the complexity of the second alternative regulatory model, as the process of defining roles and responsibilities across utilities, the PUC, and the new HERA entity may lead to additional complications. We consider the Hybrid model to be the most complex of the three alternative models, as it combines Outcomes-based PBR with two additional and complex regulatory concepts, an IGO and a DSPP. In addition to the complexitiy of adequately defining PBR outcomes and metrics to align utility incentives and policy objectives, creating the IGO will also entail the complexity of developing efficient market rules and obtaining PUC approval, as evidenced by existing ISOs frequently adjusting their rules. Furthermore, customers and market actors may have difficulty operating efficiently within the rules of a DSPP, which could lead to low participation in the process. The DSPP is also untested, which means there is uncertainty regarding the source and magnitude of the actual business model and revenue streams. Finally, the Hybrid model could also include the difficulty of integrating all three elements into a single efficient and effective regulatory model. As was true for Regulatory Cost Risk, the Hybrid model also carries a higher level of regulatory

complexity risk because a similar hybrid model has yet to be fully implemented by any other jurisdiction, so it is difficult to determine how challenging such an implementation will be.

The Project Team anticipates a Medium-High level of impact severity for ratepayers and a Medium level of impact severity for shareholders for both the Outcomes-based PBR and Conventional PBR with Light HERA models. This is because the ability of the models to function properly will have a more significant impact on ratepayers (i.e., poor service, high rates) than it will on shareholders, although shareholders will also be impacted because revenues under either PBR method are based on the utilities ability to meet performance targets. Due to the greater inherent complexity of the Hybrid model, the Project Team anticipates a High level of impact severity for ratepayers. And due to the structure of the Hybrid model, in which revenues (and therefore, cash flows to shareholders) are affected by whether the utilities are able to meet their performance targets (earnings through PIMs) and whether the DSPP component enables sufficient market activity for additional revenues, we also anticipate a High level of impact severity for shareholders.

The potential risk of Regulatory Complexity could be mitigated by working to estimate the complexity of the models to the extent possible, as this report aims to do. This risk could also be mitigated by closely monitoring the progress of the design, implementation, and operation of the models with careful attention to when complexities begin to create problems and addressing those issues as quickly as possible. Finally, in the case of and the Conventional PBR with Light HERA model, and the Hybrid model models, this risk could be mitigated by phasing the implementation of different regulatory components, or by implementing certain elements on a pilot basis (such as how New York state has used pilots to test the implementation of various components of the DSPP model).

Regarding KIUC, the Project Team expects the IGO model to provide the greatest risk for regulatory complexity, as it is more complex than HERA. Lighter PUC regulation would be expected to provide a net reduction in complexity for both KIUC and the PUC, since KIUC would no longer need PUC approval for rates, contracts, and capital expenditures in most cases (PUC approval would still be required if rate increases and capital expenditures crossed a certain threshold).

7.2.2 Regulatory Approach Does Not Yield Desired Outcomes

This section discusses the risks related to situations in which the regulatory approach does not yield the desired outcomes. This includes the risks that rates end up higher and profits end up lower than anticipated by the regulatory model, or the risk that incentives and penalties featured in the regulatory models are inadequate in their design and operation to achieve desired results. These risks are important for the State of Hawaii to consider during its evaluation of regulatory models that would mitigate the larger risks of maintaining the Status Quo because they are likely to have real impacts on ratepayers and shareholders and could also impact the overall effectiveness of the chosen PBR model.

7.2.2.1 Rates Risk

Model	Likelihood	Ratepayer Severity	Shareholder Severity
Status Quo	MH	MH	L
Outcomes-based PBR	M	MH	LM
Conventional PBR + Light HERA	M	MH	LM
Hybrid Model	M	MH	LM
Lighter PUC Regulation*	LM	MH	N/A

Relevant Phase: Transition & Ongoing
Type: Financial

The cause of the potential Rates Risk for high rates varies across the regulatory models. The Project Team notes that we are comparing rates among regulatory models, not in absolute terms. For example, one model can result in lower rates than another model, but that does not imply that rates will go down from current levels.

Under the Status Quo model, there is a risk that the Capex-based approach provides an implicit incentive for increased capital expenditures with rate-based recovery. For both PBR models (Outcomes-based and Conventional) that comprise the other regulatory models, there is a risk that the Totex approach may increase rates if the capitalization rate results in a faster increase of the regulatory asset base ("RAB") than the current (Status Quo) Capex approach. Under the Hybrid model, there is also a risk the IGO, which is envisioned as an entity that will lower power costs (and by extension, rates), will not function as intended, which could lead to higher rates.

Aside from the Status Quo model, the Project Team considers the potential Rates Risk of high rates to be consistent across the models in terms of likelihood and severity. For all three alternative models, the Project Team estimates a Medium level of likelihood that rates will be higher than anticipated, a Medium-High impact of high rates to ratepayers due to the uncertainty of how much rates would actually increase under these rate formulas in the PBR frameworks, and a Low-Medium impact on shareholders. The likelihood that rates will be higher than anticipated under that Status Quo model is considered to be Medium-High because of the aforementioned implicit incentive for utilities to increase capital expenditures to recover higher rates (though there are controls on utility capex expenditures through the existing regulatory process). As with the alternative models, for the Status Quo we assess any increase in rates as having a Medium-High impact on ratepayers. We assess this model as having a Low impact severity for shareholders because as compared to the regulatory alternatives there is a greater assurance of steady rates (and utilities' revenues) under the COS model.

The potential risk of high rates from the Status Quo model can probably be mitigated through effective regulation that scrutinizes utility expenditures that are recovered from ratepayers, or by moving the ratemaking procedure away from a Capex-based approach. Although the other regulatory models are designed to eliminate the Capex-approach of the Status Quo model, they also carry the risk that the Totex approach may not work as intended. The potential risk of high rates from the mal-design or performance of the Totex rate formula may be mitigated by carefully

researching and designing the formula to the best extent possible, as well as closely monitoring and adjusting the inputs and outputs to correct any errors promptly.

While the above analysis concerns risk for counties served by the HECO companies, rate risks may also exist for KIUC customers. These are expected to lower than for the HECO ratepayers, however, as much of the above analysis considers the potential impacts of PBR on rates (which the Project Team is not evaluating for Kauai). Still, each regulatory alternative would carry some form of rate risk, due to uncertainty regarding how the HERA and IGO models would impact utility costs and rates, and due to uncertainty of how relaxed regulatory oversight may impact the KIUC rate-setting process.

7.2.2.2 Profit Risk

Model	Likelihood	Ratepayer Severity	Shareholder Severity
Status Quo	LM	MH	H
Outcomes-based PBR	M	M	H
Conventional PBR + Light HERA	M	M	H
Hybrid Model	M	M	H
Lighter PUC Regulation*	LM	M	N/A

Relevant Phase: Ongoing
Type: Financial

Profit Risk is the potential risk that profits will be limited or will decrease as a result of the regulatory model in place. For the Status Quo model, profit risk is in some ways the converse of rate risk. In the short term, there is minimal profit risk under COS, as utilities can maintain a stable rate of return on capital investments. In the longer term, however, the threat of grid defection could constitute a profit risk under the COS model (while utility profits are decoupled from sales, in the long term the project team anticipates that increased rates of grid defection would be harmful to the utility's financial health and profits). Alternately, the utility is exposed to some profit risk if stricter regulations from the PUC could result in a reduction in the rate of return that utilities can claim on capital investments.

For the alternative regulatory models (Outcomes-based PBR, Conventional PBR with Light HERA, and the Hybrid Model) the Project Team anticipates the Totex approach of either PBR model could limit shareholder returns relative to the Status Quo, and that revenue caps also could limit returns. Profit risk could also arise from either an incorrect design of the PBR formula, higher than anticipated regulatory costs, or a situation in which lower demand growth does not support the annual growth in the proposed Capex and Opex. For the Hybrid model, in particular, the profit risk could also arise if the DSPP design and increase of DER limit future expenses and revenues.

Aside from the Status Quo model, the Project Team treats the risk of limited profits or limited growth caused by lower demand as consistent across the models in terms of likelihood, the severity of impact to ratepayers, and severity of impact to shareholders. For all three alternative

models, the Project Team estimates a Medium level of likelihood that profits will be limited by the regulatory models, a Medium level of impact to ratepayers (assuming that, in some cases, an impact on profits would eventually have an effect on rates in future PBR periods), and a High level of impact to shareholders. In terms of the Status Quo model, we estimate a Medium-High likelihood that profits will decrease under the model, a Medium-High impact of that profit decrease on ratepayers, and a High impact on shareholders.

Under the status quo, the likelihood of profit risk due to grid defection may be challenging to mitigate without a broad shift in regulatory or ownership model. Under the other models, the profit risk may be reduced by taking efforts to design the PBR formula and overall regulatory framework in the most appropriate way possible and to monitor the way the market functions once it is implemented, taking swift and careful action to make any corrections.

The Project Team assesses a low-profit risk for KIUC regulatory alternatives. KIUC, as a cooperative utility, is a non-profit entity, though profit risk may still be a relevant consideration as it relates to overall utility fiscal solvency. The Light PUC Regulation model could provide a modest risk of decreased profits/returns to cooperative members if KIUC were to become less successful without the guidance of PUC regulation for most issues. The reliability efforts created under HERA or the IGO model could also impact profits if reliability worsens significantly, or if the costs to operate either program are significantly too high.

7.2.2.3 Incentives Risk

Model	Likelihood	Ratepayer Severity	Shareholder Severity
Status Quo	L	L	L
Outcomes-based PBR	MH	MH	M
Conventional PBR + Light HERA	LM	LM	M
Hybrid Model	MH	MH	M

*Lighter PUC Regulation is not considered in this risk category because the analysis relates to incentive mechanisms contained within PBR approaches.

Relevant Phase: Transition & Ongoing
Type: Financial

PBR models are generally structured to provide incentives to utilities to improve their performance and/or achieve specific outcomes. These incentives are closely related to risks undertaken by the utilities. PBR models that provide stronger incentives are likely to create greater financial uncertainty in outcomes, but also provide the possibility for reward.[305] Incentives Risk primarily involves the potential risk that the rewards and/or the penalties in a

[305] William Zarakas et al., Performance Based Regulation Plans: Goals, Incentives and Alignment, The Brattle Group, prepared for DTE energy, available at: https://www.michigan.gov/documents/mpsc/Brattle_Report_to_DTE_on_Performance_Based_Regulation_120617_613150_7.pdf at vi (hereinafter, "Brattle Report")

given regulatory model are set too high or too low to be effective, and also includes the risk of exposure to penalties if outcomes are not met under a given regulatory model. In terms of whether the incentives are set appropriately, the Project Team notes that the stronger the incentive, the more the utilities would want to take on additional risk (for example, to invest in new technology to increase efficiency and/or cut costs), but there is a point at which the incentive-risk ratio would begin to have a diminishing return. If incentives are set too high, utilities may overcorrect or take too great a risk to meet them. If they are too low, the utilities may not take adequate action to meet them because it will not be worth their effort.

This potential risk is considered to be Low under the Status Quo model because of the relatively small role that current PIMs play in the regulatory structure compared to alternative regulatory forms (in this analysis, the Project Team is primarily considering explicit incentives and penalties that would be implemented in a PBR framework, and not implicit incentives that the utility may receive under other models). In the alternative models, there is a risk of misaligned or dysfunctional incentives when the rewards for utilities are set too high relative to the costs of meeting targets or are not set to be reflective of the actual cost to remedy any shortfall(s), as well as risks related to the incentives inherent in rate periods of varying durations. In these models, there is also a risk that penalties for missing performance targets are not high enough to deter performance and are not set to be reflective of the actual cost to remedy any shortfall(s).

Although there is some risk in each of the models because it seems plausible that any incentives would need a period of monitoring and adjustment when first implemented, and it is also difficult to determine the extent to which any misaligned incentives can be expected, the Project Team estimates that the likelihood that rewards or penalties will be set too high or too low will vary among the regulatory models. The Project Team assigns a Medium-High probability to Outcomes-based PBR models (including the Hybrid model) because of the expanded suite of PIMs that are to be imposed in those models as compared to the Conventional PBR model, which is slightly more expansive but overall more similar to the set of PIMs that currently exist under the State of Hawaii's Status Quo model. The more extensive list of PIMs under Outcomes-based PBR models means there could be more penalties under these models if outcomes are not reached, which would not only affect incentives but ultimately rates and profits as well. Consequently, we assign a Low-Medium likelihood to Conventional PBR and a Low likelihood to the Status Quo model to reflect this relationship.

For the Conventional PBR model, the Project Team estimates a Low-Medium level of impact to ratepayers. One reason for this assessment is that ratepayers will only pay for incentives if the utilities are delivering results from which ratepayers benefit, but could bear a more significant burden if incentives are too easy for the utilities to achieve and set at too high a dollar amount. The other reason is that the revenue cap mechanism in Conventional PBR could potentially mitigate some impact to ratepayers (at least within a regulatory period). The Outcomes-based PBR models would face a similar problem if incentives are too easy for utilities to achieve, but the impact on ratepayers could be greater due to the fact that the larger number of PIMs could lead to a larger aggregate impact if more or all the incentives were incorrectly set. These ratings of Medium-High probability for Outcomes-based PBR models and Low-Medium probability for Conventional PBR also reflect the incentives and risks associated with the different lengths of rate periods. For example, longer terms, such as those used in Outcomes-based PBR (5-8 years)

provides greater incentives to control costs, as well as greater possibilities to earn rewards/penalties. In contrast, the shorter terms associated with Conventional PBR (3-5 years) tend to provide less incentive to control costs, but also have less need to mitigate risks of longer time periods, as evidenced by their tendency to have fewer RAMs.[306] For the PBR models, the Project Team also estimates Medium-level severity on shareholders because it is unclear how the utilities' achievement or non-achievement of performance incentives would affect shareholders.

The potential Incentives Risk under the alternative regulatory models (Outcomes-based PBR, Conventional PBR with Light HERA, and the Hybrid Model (Outcomes-based PBR, DSPP, and IGO)) can be mitigated by designing the incentives with as much information and care as possible, and by monitoring the mechanisms' operations carefully to make timely corrections. Such corrections should modify the incentive mechanisms so that utilities are appropriately incentivized to behave in such ways that achieve the goals of the regulatory model.

As the above analysis relates primarily to incentive mechanisms contained within different PBR approaches, the project team does not consider this risk category for KIUC, for which PBR is not considered.

7.2.2.4 Low DER Risk

Model	Likelihood	Ratepayer Severity	Shareholder Severity
Status Quo	H	MH	L
Outcomes-based PBR	M	MH	L
Conventional PBR + Light HERA	MH	MH	L
Hybrid Model	LM	MH	L
Lighter PUC Regulation*	MH	MH	N/A

Relevant Phase: Ongoing
Type: Operational

The Risk of Low DER is defined as the potential risk that the regulatory model does not properly incentivize or effectuate increased DER penetration, which is a State energy goal. The Project Team treats this as a High risk under the Status Quo model, given the limited incentives provided to utilities to encourage DER penetration. The team envisions that this risk would be mitigated but not avoided under regulatory alternatives. For the models with PBR components, there is a risk that the PBR does not correctly incentivize or effectuate DER. This risk also exists under the DSPP model, which is designed to expand DER but could possibly not function as intended.

For Outcomes-based PBR, the Project Team estimates a Medium likelihood of the occurrence of Low DER due to failure or mis-design of the regulatory system. This assessment is based on the fact that the Outcomes-based PBR model is likely to incorporate increased DER penetration as the desired output, which opens the possibility that the output could not function as intended,

[306] Brattle Report at xii.

but also makes it less risky than other models that do not consider DER as a primary goal. The Project Team estimates that Conventional PBR with Light HERA has a Medium High-risk because Conventional PBR is less likely than Outcomes-based PBR to include DER as a goal, primarily since the structure of the Conventional PBR formula is based on inputs rather than outputs. In contrast, we expect the Hybrid model to have a Low-Medium likelihood of a low DER risk because DER can be an output in the PBR model, and the DSPP is intended to expand DER. While it is possible that these elements of the regulatory model will not function as intended, there is a lower risk here because there is a clearer intention to eliminate this risk. For each of these models, the severity of the impact to ratepayers is likely to be Medium-High due to the ability of DER penetration to directly affect rates and customer experience. For each of these models, the severity of the impact to shareholders is estimated as Low-Medium because changes in rates or DER penetration are less likely to affect profits but could have some effect depending on how utilities earn revenues.

The risk of low DER in the Conventional PBR with Light HERA model could be mitigated by creating incentives around DER and ensuring that HERA is capable of providing reliability for DER measures. The risks of low DER in the Outcomes-based PBR and Hybrid models can be mitigated by careful design of the PBR (and DSPP in the Hybrid model) to properly incent DER, as well as close monitoring of the PBR in operation with timely corrections when the model is not behaving as intended.

In addition to the primary analysis of Low DER Risk in relation to the counties served by the HECO companies, above, this section also briefly considers this risk in terms of KIUC on Kauai. On Kauai, this risk is lowest under the IGO model, which combines the functions of an ISO and a DSO and theoretically should encourage the development of DER. This risk could be heightened if the IGO does not operate as intended. A higher risk of low DER penetration is assumed in the HERA and reduced PUC oversight alternatives, as these would not provide any impetus to increased DER penetration. However, the Project Team acknowledges that the trade-offs between customer access to distributed renewables and the cost-effectiveness of larger renewable energy systems may be viewed differently in cooperative utility contexts than investor-owned contexts, which may impact how much consideration is given to this risk category on Kauai.

7.2.3 Reliability

This section discusses the reliability risks that may be associated with the various regulatory models. How each of the models could impact reliability is an essential topic for the State of Hawaii to consider because of the large and direct impact reliability of the electric system has on ratepayers. Additionally, this risk assessment should be of interest because the State's regulators have already shown their concern about and intent to improve reliability under the current regulatory model (e.g., by adding reliability-related PIMs and creating statutory authority for a HERA entity).

7.2.3.1 Reliability Risk

Model	Likelihood	Ratepayer Severity	Shareholder Severity
Status Quo	LM	H	LM

Outcomes-based PBR	M	H	LM
Conventional PBR + Light HERA	LM	H	LM
Hybrid Model	M	H	LM
Lighter PUC Regulation*	MH	H	N/A

Relevant Phase: Ongoing
Type: Operational

Reliability Risk is the potential risk that electric system reliability will worsen under a particular regulatory model. We assess the Status Quo as having a Low-Medium level of risk, noting that the utility is currently incentivized through existing PIMs to maintain adequate reliability standards and that reliability is monitored by the PUC, but that the continued evolution of the State of Hawaii's electric grid to accommodate new technologies may pose risks for this system – reflecting, for example, uncertainty about whether additional regulatory measures will be sufficient to maintain reliability in increased DER penetration scenarios that pose increased grid complexity.

With the addition of HERA, an independent body focused primarily on setting grid reliability standards, and monitoring and ensuring utilities' compliance with reliability standards under the oversight of the PUC, we assess this risk as Low-Medium because HERA is intended to improve reliability. However, this risk is not entirely neutralized because of the possibility that HERA may not function as intended or may not result in an improvement in system reliability. The Project Team considers inclusion of Outcomes-based PBR as leading to increasing reliability risk, as the incentive signals sent to utilities through new outcomes may encourage utilities to optimize their operations to favor other outcomes above reliability (although reliability would be expected to be included as a desired PBR outcome), and so the Outcomes-Based PBR model is assessed as having a Medium level of risk. Additionally, although the IGO and DSPP are also intended to improve reliability, the complexity in grid operations provided by the creation of an IGO and DSPP may lead to high levels of reliability risk. Therefore, the Hybrid model is assessed as having a Medium-High level of risk.

Under each of the models considered, the impact to ratepayers of poor reliability is High because poor reliability directly causes ratepayers to experience loss of service or poor-quality service. Shareholders do not experience reliability issues first-hand but would be impacted somewhat if utilities are not able to claim incentives (or must pay penalties) for PIMs associated with reliability. Shareholder severity is thus rated at Low-Medium for all models.

The potential reliability risks under the alternative regulatory models can be mitigated through careful design of reliability mechanisms and regulations, and by monitoring the mechanisms' or reliability enforcement bodies' operations carefully and making timely corrections as necessary.

The Project Team also briefly assesses these risks for the regulatory models proposed for Kauai. We anticipate that the Light PUC Regulation model would carry the most risk relatively for worsened reliability due to relaxed PUC oversight. While KIUC, as a member-owned cooperative, is considered to have adequate internal incentives to maintain reliability, a reduction in PUC oversight may create possibilities for risk. Meanwhile, the IGO and HERA models both

aim to improve reliability, but carry some risk of worsened reliability in the event that either model doesn't function as intended. This risk is greater for the IGO model, which is more complex than the HERA model.

7.2.4 Infrastructure

This section addresses the risk that the regulatory models considered in this report would support the development of inefficient infrastructure. This is an important risk for the State of Hawaii to consider because of the implications that inefficient infrastructure could have on the State's ability to improve the entire grid and especially generation. Careful consideration of this risk could help the State to be more responsive to its changing needs and to be more cost-effective. This section aims to provide some guidance on this topic so that the State can understand which model might be best suited to prevent the growth of inefficient infrastructure.

7.2.4.1 Inefficient Infrastructure Risk.

Model	Likelihood	Ratepayer Severity	Shareholder Severity
Status Quo	H	H	L
Outcomes-based PBR	M	MH	L
Conventional PBR + Light HERA	LM	MH	L
Hybrid Model	LM	MH	L
Lighter PUC Regulation*	L	M	N/A

Relevant Phase: Ongoing
Type: Financial

The Risk of Inefficient Infrastructure incorporates the potential risk that the utilities continue to hold onto, or continue to invest in and thus overbuild, expensive generation assets (and to a lesser extent of importance, distribution and transmission assets), and the potential risk of stranded costs if utilities' existing infrastructure becomes redundant amid a regulatory change or shift in the market environment. Under the Status Quo model, the financial incentives granted to utilities create opportunity for a risk of inefficient infrastructure, as utility profits are tied to the capital expenditures. Under the alternative models, the risk of inefficient infrastructure would arise if the PBR model fails to remove the Capex-based incentive to make inefficient capital investments. Additional and more minor risks under the alternative models could also include failure to properly retire expensive generation assets, and failure to shift investment to DER generation and update the grid, as appropriate.

The Project Team anticipates that the likelihood of inefficient infrastructure risk occurring under the Status Quo model is High because the inherent design of the Capex based model is to maximize capital investment. Because the resulting potential for inefficient- or over-investment in generation assets could tie up costs, rates could increase or decrease with respect to the other models (not in absolute terms), which would have a High impact on Ratepayers. Under the Status Quo model, the impact of the risk to shareholders should be lower than the impact to ratepayers because shareholders are not directly impacted by rate increases. Regarding the alternative

models, the Project Team estimates a Medium likelihood that Outcomes-based PBR would be able to achieve the results that would break the incentive to maximize capital investment, or incentivize efficient investment in infrastructure, because it is outputs based but could be complicated to implement correctly. For Conventional PBR with Light HERA, we estimate a Low-Medium likelihood of risk for inefficient infrastructure because the model encourages efficiency by setting cost budgets upfront, effectively requiring the utilities to operate within a limited budget and rewarding them if they come in under budget. We also estimate a Low-Medium likelihood of risk for the Hybrid model because the inclusion of the IGO to the Outcomes-based PBR model would help to ensure efficient generation planning. If any of the models fail to accomplish such objectives, the risk to ratepayers would be at a Medium-High level of impact due to the fact that such inefficiencies would probably increase rates, whereas the risk to shareholders would be lower for the same reasons described above (i.e., during discussion of Status Quo impacts for this risk).

The potential Inefficient Infrastructure Risk under the Status Quo model can be mitigated by transitioning to alternative regulatory models such as those considered in this report, which could reduce the incentives to engage in capital investment decisions, and possibly even provide financial incentives and other benefits to assist with the efficient retirement of old expensive generation infrastructure and the investment in more efficient infrastructure. Inefficient infrastructure risk under the alternative models can be mitigated through the careful and informed planning of the PBR model(s), and close monitoring and timely correction of the operating models if they begin producing unintended consequences.

While the above analysis primarily focuses on Inefficient Infrastructure risk for counties served by the HECO Companies, the Project Team also briefly considers this risk in terms of KIUC on Kauai. The Project Team anticipates that the risk of inefficient infrastructure on Kauai is approximately equal among the three proposed regulatory models, because they all are still considered within the cooperative model and are not expected to be very impacted by less PUC regulation or the addition of additional reliability entities.

7.3 Conclusion of Risk Analysis

Through this risk assessment exercise, the Project Team has determined that the potential risks associated with the four regulatory models are likely to differ within the eight risk categories. The regulatory models in this assessment include the Status Quo (COS), Outcomes-based PBR, Conventional PBR with Light HERA, and the Hybrid model. The risk categories include regulatory costs, regulatory complexity, rates, returns, incentives, reliability, low DER, and infrastructure inefficiency. Overall, the likelihood of the risk is the most variable risk assessment measure among the four models in each risk category, with different results among at least three out of four models for all the risks except rates and returns. The variation of likelihood assessments emphasized the differences in the design and purpose of the various four regulatory models. For example, for the regulatory complexity risks, the likelihood that the models' implementation and operation would be more complicated than anticipated varied in relation to how complex each model is (or how different they are from the Status Quo); with the likelihood for risk for the Status Quo model at Low, Outcomes-Based PBR and Conventional PBR with Light HERA at Medium (same level to account for the increased complexity of Outcomes-based PBR

in comparison to Conventional PBR, but adding complexity to the Conventional PBR model due to its incorporation of HERA), and Hybrid model at High, which combines the more complicated PBR model with two additional models (IGO and DSPP).

In contrast, the severity of the impact to ratepayers and shareholders is largely consistent between the models for each risk. In terms of severity of risk impact to ratepayers, the impact varies between models for costs, complexity, and incentives risks but is overwhelmingly consistent for the other risks. For these other categories, the Project Team anticipates that ratepayers under any of the models can expect High severity for reliability risks, Medium-High severity for rates, low DER, and infrastructure inefficiency risks, and Medium severity profits risks. In terms of severity of impact on shareholders, the impact is generally consistent (with the occasional exception under the status quo) among the risks. The Project Team anticipates that shareholders across the models may experience High severity for returns risk, Medium severity for incentives risk, Low-Medium severity for regulatory costs, regulatory complexity, rates, and reliability risks, and Low risk for low DER and infrastructure inefficiency risks.

Through this risk assessment exercise, the Project Team has also determined some of the mitigation strategies that exist to reduce risk. In general, for risks likely to be experienced under the Status Quo model, the mitigation strategy is to implement another regulatory model, such as those considered in this report. For those alternative models, the general mitigation strategy is informed and careful design of the model, and a commitment to monitoring the model's performance and to make timely corrections as necessary.

Figure 11. Summary of Risks for Each Regulatory Model

RISK	Model	Likelihood	Ratepayer Severity	Shareholder Severity	Description
Regulatory Cost	Status Quo	L	LM	L	Risk that implementation and operation of regulatory model will be more expensive than anticipated.
	Outcomes-based PBR	MH	MH	LM	
	Conventional PBR + Light HERA	M	M	LM	
	Hybrid Model	H	MH	LM	
	Lighter PUC Regulation*	LM	LM	N/A	
Regulatory Complexity	Status Quo	L	M	M	Risk that implementation and operation of regulatory model will be more complicated than anticipated.
	Outcomes-based PBR	M	MH	M	
	Conventional PBR + Light HERA	M	MH	M	
	Hybrid Model	H	H	H	
	Lighter PUC Regulation*	L	L	N/A	
Rates	Status Quo	MH	MH	L	Risk that design of the regulatory model will cause rates to increase.
	Outcomes-based PBR	M	MH	LM	
	Conventional PBR + Light HERA	M	MH	LM	
	Hybrid Model	M	MH	LM	
	Lighter PUC Regulation*	LM	MH	N/A	
Profit	Status Quo	LM	MH	H	Risk that design of the regulatory model will cause profits to decrease.
	Outcomes-based PBR	M	M	H	
	Conventional PBR + Light HERA	M	M	H	
	Hybrid Model	M	M	H	
	Lighter PUC Regulation*	LM	M	N/A	
Incentives	Status Quo	L	L	L	Risk that incentives and penalties in the regulatory models will be ineffective in driving utility behavior.
	Outcomes-based PBR	MH	MH	M	
	Conventional PBR + Light HERA	LM	LM	M	
	Hybrid Model	MH	MH	M	
Low DER	Status Quo	H	MH	L	Risk that regulatory model will cause low DER penetration.
	Outcomes-based PBR	M	MH	L	
	Conventional PBR + Light HERA	MH	MH	L	
	Hybrid Model	LM	MH	L	
	Lighter PUC Regulation*	MH	MH	N/A	
Reliability	Status Quo	LM	H	LM	Risk that regulatory model implementation and operation will cause reliability to worsen.
	Outcomes-based PBR	M	H	LM	
	Conventional PBR + Light HERA	LM	H	LM	
	Hybrid Model	H	H	LM	
	Lighter PUC Regulation*	MH	H	N/A	
Infrastructure Inefficiency	Status Quo	H	H	L	Risk that regulatory model will incentivize capital development and create inefficient infrastructure.
	Outcomes-based PBR	M	MH	L	
	Conventional PBR + Light HERA	LM	MH	L	
	Hybrid Model	LM	MH	L	
	Lighter PUC Regulation*	L	M	N/A	

Appendix A: Scope of Work to Which this Deliverable Responds

2.3.1 – Identification of steps, costs, and projected timelines, for change from the current regulatory model to the recommended regulatory models.

CONTRACTOR shall identify the steps and costs required, along with a projected timeline, to change the regulatory model in the State, including all necessary approval requirements.

CONTRACTOR shall provide all work to identify the steps required to change from the current regulatory model to each recommended regulatory model. CONTRACTOR shall summarize findings in a user-friendly document detailing the steps and tying each step to the costs (or cost ranges) required for the step. CONTRACTOR shall include a written description of the analysis in MS Word and an MS Excel spreadsheet. CONTRACTOR shall submit deliverable for TASK 2.3.1 to the STATE for approval.

2.3.2 – Analysis of Hawaii law and history to determine the regulatory and legislative changes needed to implement the recommended regulatory models.

CONTRACTOR shall conduct a detailed analysis to determine the legality of the regulatory models. This analysis shall identify any required changes to existing statutes or regulations and if any proceedings are necessary. The analysis shall also estimate costs, timing, and strategies for navigating through each proceeding.

CONTRACTOR shall provide all work to examine Hawaii law and history to determine the regulatory and legislative changes needed to implement the recommended regulatory models. CONTRACTOR shall identify a series of regulatory categories and (a) examine them against Hawaiian legislation and statutes; and (b) benchmark them against regulatory statutes and documentation governing utility legal and regulatory structures in Hawaii and other jurisdictions. CONTRACTOR shall identify gaps in current legislation, include results of targeted interviews with other jurisdictions to determine level of difficulty of proposed changes, and provide the necessary analyses to support legal changes, timing and cost estimates. CONTRACTOR shall include a written description of the analysis in MS Word and an MS Excel spreadsheet, if appropriate. CONTRACTOR shall submit deliverable for TASK 2.3.2 to the STATE for approval.

2.3.3 – Identification and assessment of impact of known or potential financial and operational risks for different shareholders (ratepayers, utility shareholders, taxpayers) under each regulatory model.

CONTRACTOR shall identify the known and potential financial and operational risks and bearer of those risks (e.g. ratepayers, utility shareholders, taxpayers) under each regulatory model.

CONTRACTOR shall provide all work to identify and analyze the risks facing each stakeholder group during the two stages required to transition to a new regulatory model: (1) during the transition; and (ii) during the operation of the new model. CONTRACTOR shall include, for

each relevant stakeholder, a summary of their expected view of the new regulatory model, identified risk, estimated likelihood of the risk, estimated potential severity or impact, and consideration of the adequacy of typical risk mitigations. CONTRACTOR shall assess the overall risk profile as it relates to different stakeholders for each regulatory model option and present the analysis in a comparable way. CONTRACTOR shall include a written description of the analysis in MS Word and an MS Excel spreadsheet, if appropriate. CONTRACTOR shall submit deliverable for TASK 2.3.3 to the STATE for approval.

Appendix B: List of Works Consulted

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Assessment of the impact of the regulatory change to the staffing of relevant State agencies

prepared for Hawaii DBEDT by London Economics International LLC

December 28, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals; this document is one of several working papers associated with that engagement. This memo, which corresponds to Task 2.3.4, evaluates the impact of the recommended regulatory change structure to the staffing needs of relevant state agencies (such as Public Utilities Commission ("PUC"), and the Division of Consumer Advocacy ("DCA")). Based on our analysis, we conclude that the implementation of the Outcomes-based Performance-Based Regulation ("PBR") model could require a change in the number of staff (which could be higher or lower). However, moving towards the Conventional PBR with Light Hawaii Electricity Administrator ("HERA") model or the Hybrid model may increase staffing needs. Moreover, the staff's expertise, as well as the organizational breakdowns (divisions), are very similar amongst the different potential regulatory models. The goals and complexity of energy policies, too, have impacts on the management and staffing needs of these agencies.

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List of acronyms

AUC	Alberta Utilities Commission
CUB	Citizens Utility Board
DBEDT	Hawaii Department of Business Economic Development and Tourism
DBF	Department of Budget & Finance
DCA	Division of Consumer Advocacy
DCCA	Department of Commerce and Consumer Affairs
DERs	Distributed energy resources
DPS	Department of Public Service
DSPP	Distributed System Platform Provider
EIMA	Energy Infrastructure Modernization Act
FTE	Full-time equivalent
GEMA	Gas and Electricity Markets Authority
HECO	Hawaiian Electric Company
HELCO	Hawaii Electric Light Company
IGO	Integrated Grid Operator
IPART	Independent Pricing and Regional Tribunal
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company
NASUCA	National Association of State Utility Consumer Advocates
NER	National Electricity Rules
NSW	New South Wales
NY PSC	New York Public Service Commission
OCC	Office of Consumer Counsel
OEB	Ontario Energy Board
Ofgem	Office of Gas and Electricity Markets
PPAs	Power purchase agreements
PUC	Public Utilities Commission
REV	Reforming the Energy Vision
RIIO	Revenue = Incentives + Innovation + Outputs
RPS	Renewable Portfolio Standards
RRFE	Renewed Regulatory Framework for Electricity
ST	Suruhanjaya Tenaga
TNB	Tenaga Nasional Berhad
UCA	Office of the Utilities Consumer Advocate
UCB	Utility Consumers' Board
UK	United Kingdom

1 Executive Summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which corresponds to Tasks 2.3.4 in the project scope of work, provides an estimate of the potential impacts a change in the regulatory model may have on the expertise and staffing requirements of related State agencies. Although several state agencies interact with the electric utilities, we are focusing this paper on similar agencies such as the Hawaii Public Utilities Commission ("PUC") and the Division of Consumer Advocacy ("DCA") in Hawaii. We have reviewed standard practices in other jurisdictions with the three potential regulatory models that were recommended in Task 2.2.6 and provided an assessment of the impact of the regulatory change to the staffing of relevant State agencies under each model.

As discussed in Task 2.2.6, the three recommended regulatory models for the City and County of Honolulu, County of Maui, and County of Hawaii include (i) Outcomes-based PBR, (ii) Conventional PBR with Light HERA, and (iii) the Hybrid model[1]. As discussed in previous working papers, the Hybrid model includes an Outcomes-based PBR, a Distributed System Platform Provider ("DSPP") and an Integrated Grid Operator ("IGO")).

Since these three recommended models are relatively innovative, only a few jurisdictions have some elements of these recommended models in their current regulatory framework, so the Project Team selected some jurisdictions for further review of staffing in relevant agencies. The United Kingdom (the "UK") and Ontario were chosen to represent the Outcomes-based PBR model. Illinois, Alberta, and New South Wales were selected to represent the Conventional PBR with Light HERA model.[2] Since no jurisdiction currently has the Hybrid model, we selected New York as an example since it is under the Reforming the Energy Vision ("REV") that have similar elements of Outcomes-based PBR as well as DSPP. New York also has an independent system operator. We compared the staffing numbers before and after the change of regulatory models to study the impact of the change on staffing relevant State agencies.

Our primary observations include the following:

- The jurisdiction (i.e., New York State) that is moving towards a Hybrid model has a higher staff-to-customers ratio in the PUC than jurisdictions with other regulatory models. This is because of the more complex regulatory framework under a Hybrid model that requires more technical staff to design and monitor the regime;

[1] As for the recommended regulatory models for the County of Kauai, the "Lighter PUC Regulation" model will obviously require fewer staff members in the Hawaii PUC. Detailed discussion on representative states that have lighter PUC regulation has been included in Section 5.3.2 Cooperative under Task 1.3.4.

[2] Since HERA does not exist in Hawaii and there is no similar entity in other jurisdictions, this section focuses on jurisdictions that implemented Conventional PBR only.

- Outcomes-based PBR-dominated and Conventional PBR-dominated jurisdictions, such as the UK, Ontario, Malaysia, Alberta, and New South Wales, have a lower staff-to-customers ratio in the PUC than the jurisdiction (i.e., New York State) with the Hybrid model;
- When implementing PBR mechanisms, the PUCs usually hire external consultants, which could result in the unchanged staffing needs.
- Jurisdictions with more ambitious and active clean energy policies or initiatives tend to have more staff members but not necessarily higher staff-to customers ratio in relevant regulatory agencies;
- Staff's skill sets and expertise are very similar across different regulatory models; and,
- The divisions under regulatory agencies are organized by function, like engineering, policy research, personnel, administration, etc.; these organizational breakdowns are similar across different regulatory models.

Based on the analysis of representative jurisdictions, we anticipate the following potential impacts on the staffing requirements of related agencies.

- The impact of an **Outcomes-based PBR model** on staffing needs is inconclusive, since the staffing needs increased in the UK, but stayed constant in Ontario after the implementation of this model (this outcome could be explained by the hiring of consultants);
- Implementation of the **Conventional PBR with Light HERA model** would potentially increase the staffing needs; and,
- Implementation of **the Hybrid model** could result in higher staffing needs than the status quo.

Furthermore, as mentioned in Task 1.3.4 and 1.4.3, the oversight management and staffing needs of related State agencies and stakeholders will be affected by various factors other than the regulatory model. Although the Hawaii PUC only regulates four electric utility companies,[3] Hawaii's aggressive renewable portfolio standards ("RPS") and other policy goals entail additional challenges to the regulatory and policy agencies. These other factors may require more staff members in these agencies, regardless of the regulatory model selected. Moreover, this analysis is a relative comparison for the purposes of comparing alternative utility ownership models. The study was not designed to assess whether or not the Hawaii PUC was appropriately staffed to meet the current demands. Our analysis was not intended to be used as an assessment of the appropriate staffing level given the specific considerations and issues for the Hawaii PUC and DCA, which is outside the scope of this study.

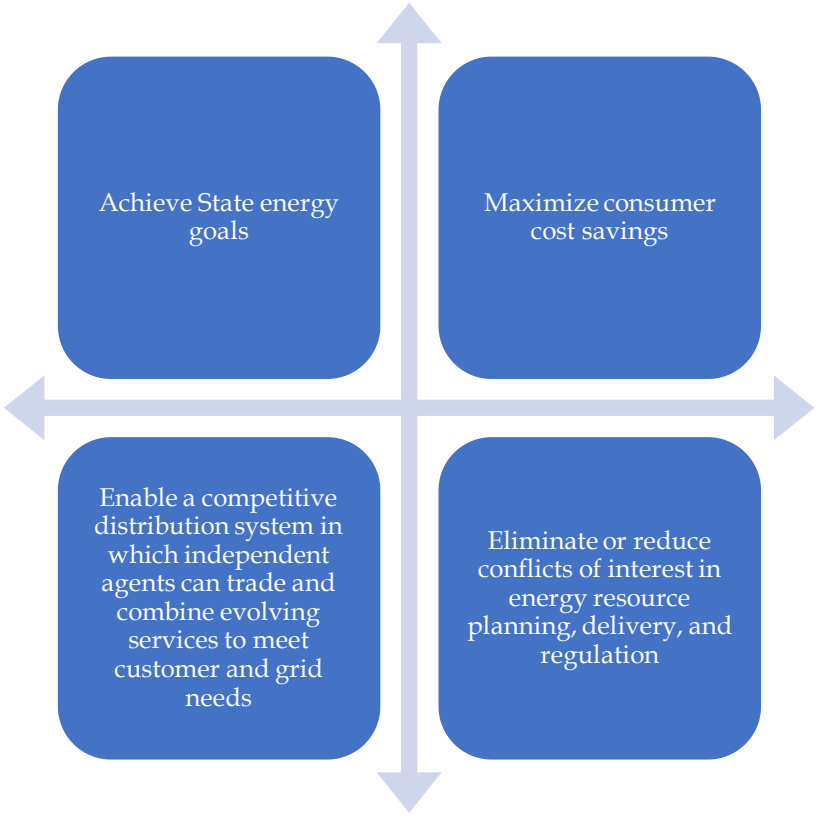
[3] As discussed in Section 3.1, in addition to the electric utilities, the Hawaii PUC also regulates gas, telecommunications, water carriers and motor carriers transportation, as well as water and waste-water services.

2 Introduction and scope

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission on a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[4] was contracted to perform this study.[5]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[6] listed in Figure 1.

Figure 1. State's key criteria in evaluating the models



Source: Scope of Services under Contract No. 65595

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In

[4] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[5] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[6] House Bill No. 1700 Relating to the State Budget.

addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[7]

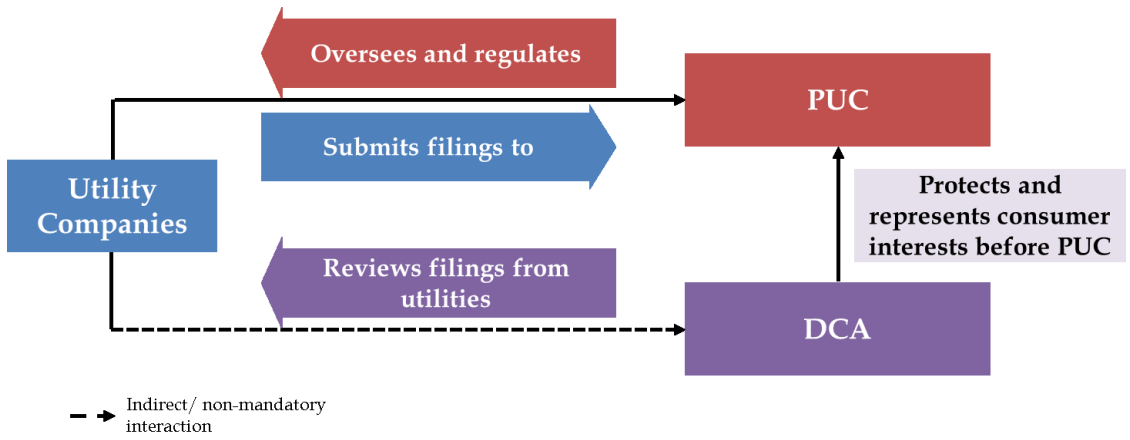
This deliverable corresponds to Task 2.3.4 in the project scope of work. It provides an estimate of the potential impacts a change in the regulatory model may have on the expertise and staffing requirements of related State agencies and stakeholders such as Hawaii PUC, and the DCA. In addition, it includes analysis of best practices in terms of staffing and expertise at public utility commissions and consumer advocate offices.

[7] Hawaii Contract No. 65595. Scope of Services.

3 Current staffing structure

A change in utility ownership might impact the various state entities that help oversee that utility or provide it with policy guidance. To assess the potential impact, we focus on State agencies and regulators that utilities usually interact with, including the Hawaii Public Utilities Commission ("PUC") and the Hawaii Division of Consumer Advocacy ("DCA"). Figure 2 summarizes the main interactions between these entities. All the utility companies in Hawaii are overseen and regulated by the PUC. Utilities are required to submit filings to the PUC regarding their proposed rates, changes, and future plans, and power purchase agreements ("PPAs") with generators, to name a few. Although utility companies are not required to report to the DCA directly, the DCA reviews filings from utilities and represents consumer interests before the PUC. These agencies are the most likely to be impacted by any ownership change of Hawaii's utility companies. We will discuss the current staffing structure of each entity below.

Figure 2. Utilities' interaction with PUC and DCA



Source: PUC, DCA, and LEI analysis.

3.1 Hawaii Public Utilities Commission

The primary duty of the PUC is to "*protect the public interest by overseeing and regulating public utilities to ensure that they provide reliable service at just and reasonable rates.*"[8] Entities that are regulated by the PUC include companies that provide electricity, gas, telecommunications, water carriers, and motor carriers transportation, as well as water and waste-water services. In addition, the Hawaii PUC directly oversees Hawaii Energy, funded by a public benefits fund, and the Hawaii One Call Center, a mandatory "Call Before You Dig" program, among other programs. All the electricity utilities, namely Hawaiian Electric Company, Inc. ("HECO"), Maui Electric Company, Limited ("MECO"), Hawaii Electric Light Company, Inc ("HELCO"), and Kauai Island Utility Cooperative ("KIUC"), are under the authority of the PUC.

[8] HPUC. *Introduction*. Website< http://puc.hawaii.gov/about/introduction/>. Access date: October 30, 2017.

As requested by the Act 108, Session Laws of Hawaii 2014, the PUC was transferred from Department of Budget & Finance ("DBF") to the Department of Commerce and Consumer Affairs ("DCCA").[9] Given its increased administrative decision-making authority, the PUC also received additional funding that led to more staffing positions.[10] As of December 2016, the PUC has a total of 65 full-time, permanent, and funded positions; 85% of those positions were filled in FY 2016.[11] Positions include administrative, director, attorneys, engineers, auditors, researchers, investigators, neighbor island representatives, documentation staff, and clerical staff.[12] The PUC recruited and filled 23 vacant positions in FY 2017.[13] The funded positions in each division and the relevant background/expertise of staff are summarized in Figure 3.

Figure 3. Number of staff and their major background/ expertise in each division in Hawaii PUC

Divisions	Approximate # of Staff	Major background/ expertise of Staff
Office of the Commissioners	7	management, development, administration
Commission Counsel	11	legal advisory
Audit Section	4	auditing, research, analysis
Engineering Section	4	engineering, analysis
Consumer Affairs and Compliance	9	public relations, complaint resolution
Administrative Support Services	10	documentation, clerical services, information technology, coordination
Fiscal Section	3	fiscal and procurement
Personnel Section	2	recruitment, human resources
Policy and Research	15	analysis, economics, research

Source: Hawaii PUC. Response to LEI's data requests via email on November 21, 2017.

3.2 Division of Consumer Advocacy

The Division of Consumer Advocacy ("DCA") is under the DCCA. The DCA is a state agency established to "*protect and represent consumer interests before the Hawaii PUC, the Federal Communications Commission, and other local and federal agencies*."[14] It should be noted that the DCA "*assists and represents customers of utility services as a whole rather than a single customer or select group*

[9] "Commission History." *HPUC*. Website. < http://puc.hawaii.gov/about/history/>. Access date: October 30, 2017.

[10] HPUC. *Annual Report for Fiscal Year 2016* (July 1, 2015 to June 30, 2016). December 2016, page 5.

[11] Ibid, page 5.

[12] HPUC. *Annual Report for Fiscal Year 2012-13*. January 2014, page 2.

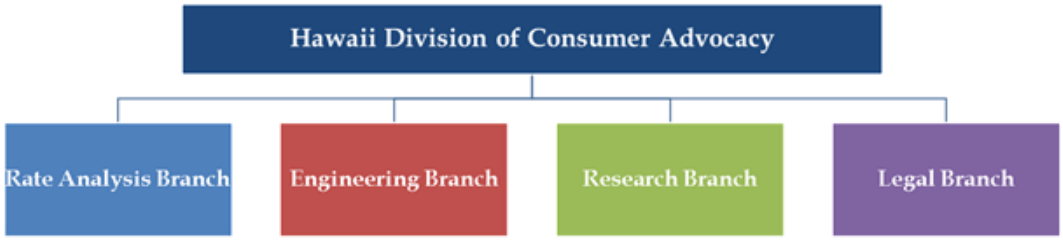
[13] HPUC. *Annual Report for Fiscal Year 2017* (July 1, 2016 to June 30, 2017). December 2017, page 5.

[14] "Divisions." *DCCA*. Website. < http://cca.hawaii.gov/divisions/>. Access date: October 31, 2017.

of people."[15] More specifically, the DCA reviews filings from public utility and transportation companies, including rate and tariff changes, capital improvement projects, integrated resource plans, certificates for authority to operate, etc.[16] In representing consumer interests before the PUC, the DCA files written statements of position or provides testimonies based on its analysis of "*financial and statistical data, prior docketed material, industry standards, and the information provided by utility and transportation companies to support their applications*."[17]

As of 2016, DCA had 19 employees, including an Executive Director, a secretary, a utilities/transportation officer, a utilities/transportation specialist, an education specialist, rate analysts, researchers, engineers, attorneys, and clerical support.[18] Most of the professional staff are under four branches, including the Rate Analysis Branch, the Engineering Branch, the Research Branch, and the Legal Branch as shown in Figure 4 below. The Rate Analysis Branch reviews the capital structure of utilities and develops recommendations relating to rates. The Engineering Branch analyzes and makes recommendations on technical matters. The Research Branch analyzes and provides advice relating to the operations of and changes to utilities. The Legal Branch provides legal representation before regulatory agencies.[19]

Figure 4. Organizational chart of Hawaii DCA



Source: DCA. 2016 Compliance Resolution Fund Report.

[15] Ibid.

[16] DCA. *2016 Compliance Resolution Fund Report*. Page 22.

[17] Ibid.

[18] Ibid.

[19] Ibid, Page 22-23.

4 Best practices in staffing in other jurisdictions

4.1 Public Utilities Commission

In the US, PUCs or PSCs consist of three to seven appointed or elected commissioners and professional staff who may carry the following functions.[20]

- *managing their personnel, facilities, operations: administrative staff;*
- *conducting hearings: administrative law judges, hearings examiners, attorneys;*
- *analyzing rate filings through testimony (usually pre-filed): economic, accounting and engineering staff;*
- *enforcing rules and tariffs: compliance staff, attorneys;*
- *providing technical assistance to the commissioners: advisory staff;*
- *legal analysis: attorneys;*
- *legislative analysis and reporting: policy staff; and facilitating alternative dispute resolution processes, including settlement negotiations among parties.*

Staffing in the Hawaii PUC conforms to the industry standard, given that it has three Commissioners that are appointed by the Governor and subject to confirmation by the state Senate.[21] Its functions are also consistent with the ones provided above.

The organizational chart of California PUC was used as an example to illustrate the functional lines of a typical commission in the *Electricity Regulation in the US: A Guide* published by The Regulatory Assistance Project (or "the Guide"), as shown in Figure 5. Although not every PUC or PSC is the same, this organizational chart provides an overview of the range of functions that a commission performs.[22] According to the Guide, in some states, "*the commission staff does not prepare any evidence of its own.*"[23] And in a few states, the consumer advocate is part of the commission.[24] Also, since each commission regulates a different number of utilities which serve a different number of customers, the number of staff that a PUC needs to employ varies as well. The Hawaii PUC has some divisions that are like the ones in the California PUC. For example, the Hawaii PUC has a Consumer Affairs and Compliance division which is like the Consumer Services & Information and the Consumer Protection & Safety divisions in the California PUC. But the Hawaii PUC also has some functional divisions like Engineering Section, Fiscal Section, Policy, and Research division that the California PUC does not have. The California PUC,

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[20] Lazar, J. *Electricity Regulation in the US: A Guide. Second Edition*. Montpelier, VT: The Regulatory Assistance Project. 2016. pages 25-26.

[21] Section 26-34 of the Hawaii Revised Statutes.

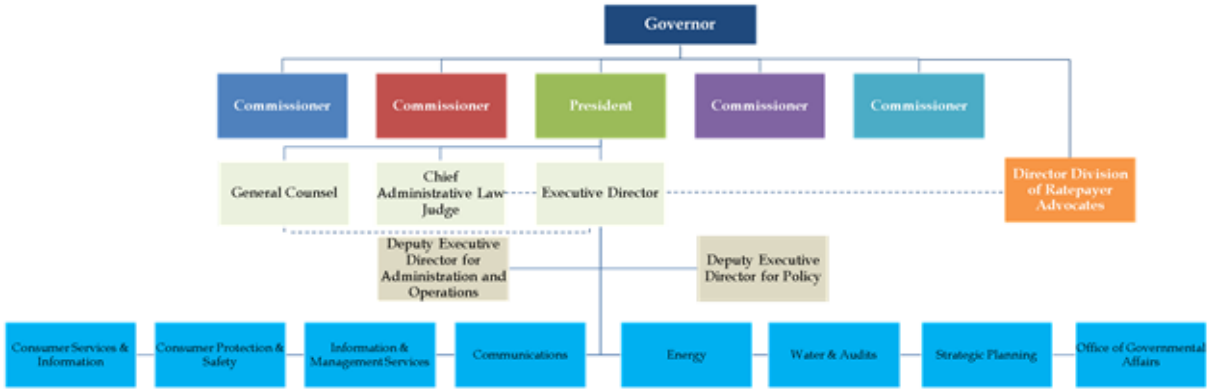
[22] Lazar, J. Electricity Regulation in the US: A Guide. Second Edition. Montpelier, VT: The Regulatory Assistance Project. 2016. pages 25-26.

[23] Ibid.

[24] Ibid.

however, has divisions that are specialized in certain industries like the Energy Division and the Water & Audits division that the Hawaii PUC does not have.

Figure 5. Organizational chart of California PUC



Source: CPUC, 2016. Lazar, J. Electricity Regulation in the US: A Guide. Second Edition. Montpelier, VT: The Regulatory Assistance Project. 2016. Page 26.

4.2 Division of Consumer Advocacy

According to the National Association of State Utility Consumer Advocates ("NASUCA"), state utility consumer advocate offices were created by state legislatures in the 1970s, when natural gas and electric prices were very high during energy crises.[25] The consumer advocates were responsible for challenging the rate increases by the utility monopolies. Later, as the competition and industry deregulation evolve, state consumer advocates shift their focus to "*consumer protection issues, including service quality, reliability, and price stability.*"[26] The names of these offices vary in different states, including "*People's Counsel, Public Counsel, Consumer Advocate, and Consumer Counsel.*"[27] The Hawaii DCA has these tasks as part of its mandate.

Based on LEI's research, the DCA in Colorado could serve as a good example of a well-organized office, as the DCA in Colorado helped the customers save $66 for every dollar the DCA spent. The Colorado Department of Regulatory Agencies has been checking the state regulation through the various process for 40 years. They believed that "*when unnecessary or overly restrictive regulations create barriers for new practitioners and businesses to succeed, the effects can reverberate throughout the economy.*"[28] The Office of Consumer Counsel ("OCC") under the Department of

[25] "Who We Are – The History of NASUCA." *NASUCA*. Web. <http://nasuca.org/about-us/>.

[26] Ibid.

[27] Ibid.

[28] "Celebrating 40 Years of Sunset and Regulatory Reform." *Colorado Department of Regulatory Agencies*. Website. <https://www.colorado.gov/pacific/dora-oprrr/40-years-reform>.

Regulatory Agencies serves as the consumer advocate office in Colorado. The OCC was created by the legislature in 1984 to "*represent the public interest and the specific interests of residential, small business and agricultural consumers in electric, natural gas, and telecommunications rate and rulemaking cases before the PUC, federal agencies, and the courts*."[29] The passing of *SB 271* in the legislative session eliminated telecommunications from the OCC's advocacy, which left OCC to focus on energy-related issues.[30]

The OCC has an eleven-member Utility Consumers' Board ("UCB") created statutorily. As the recent legislation required, seven of the members are appointed by the Governor, and each of the seven Congressional districts in the state shall be represented.

Moreover, "*no more than four Board members can be affiliated with the same political party*."[31] At least one member of the seven appointments will be representing expertise in agriculture, and at least two members of the seven appointments will be owners of the small business with 100 or fewer employees.[32] For the four remaining seats, "*the President of the Senate, Speaker of the House of Representatives, the Minority Leader of the Senate, and the Minority Leader of the House of Representatives shall each appoint one member.*"[33] The UCB is primarily responsible for providing general policy guidance and oversight to the OCC and its director. The Attorney General should advise the OCC and UCB on all legal matters and provide representation in proceedings.[34]

In addition, the OCC has eleven staff members in total, including seven operational staff (director, deputy director, admin, four technical analysts) and four legal staff (three attorneys and one legal assistant). [35] The background of technical analysts includes economics, engineering, policy analysis, etc.[36] Qualified external experts are also contracted with the OCC to perform research

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[29] "About the Office of Consumer Counsel." *Colorado Department of Regulatory Agencies*. Web. <https://www.colorado.gov/pacific/dora/about-office-consumer-counsel>.

[30] Ibid.

[31] "About the OCC – Utility Consumers' Board." *Colorado Department of Regulatory Agencies.* Web. <https://www.colorado.gov/pacific/dora/what-we-do-OCC>.

[32] Ibid.

[33] Ibid.

[34] Ibid.

[35] Tim Villarosa, Deputy Director of the Office of Consumer Counsel. Reply to LEI's data request via email. November 27, 2017.

[36] "Advocacy – What We Do." *Colorado Department of Regulatory Agencies.* Web. <https://www.colorado.gov/pacific/dora/what-we-do-OCC>.

and appear as an expert witness in proceedings.[37] Like the OCC, the Hawaii DCA also has staff members who focus on analysis, engineering, and legal tasks.

As for funding, the OCC is "*cash funded by the PUC Fixed Utility Fund into which public utilities pay to cover the cost of regulation*" and "*no state General Fund dollars are appropriated to the OCC.*"[38] In the Fiscal Year 2015-2016, the annual budget for OCC totals $1.7 million (including personal and legal services, operating, information technology, leased space, and indirect costs), and the OCC managed to save consumers $111 million in energy rate hikes through singular and joint efforts with the PUC staff.[39] In other words, for every dollar the OCC spent (including the management and staffing expenditures), Colorado consumers saved $66 in total.[40]

In summary, lessons learned from the OCC in Colorado can be summarized in two points. First, the statue had specific requirements on the appointed UCB members, which brings representatives from different fields with diverse expertise and political views. It is an effective way to guarantee the OCC represents interests of general consumers, especially those with less representativeness (i.e., small business). Second, the OCC is relatively transparent and cost-effective, as it can document the consumer savings for every dollar the OCC spent.

[37] Ibid.

[38] Colorado Department of Regulatory Agencies. *Office of Consumer Counsel FY 2015/2016 Annual Report*. Page 4.

[39] Ibid, page 3.

[40] Ibid, page 11.

5 Regulatory and policy staffing requirements under each regulatory model

5.1 Key issues

As with the broader project, in this phase, we seek to understand whether a change in a regulatory model affects the regulatory and policy staffing requirements of agencies such as the PUC and DCA and, if so, what the impacts are. In Section 3, we summarized the current staffing of these agencies in Hawaii. In this section, we reviewed and evaluated the regulatory and policy staffing requirements under each regulatory model in other jurisdictions. We assessed the staffing requirements of these agencies in representative jurisdictions under each regulatory model.

5.2 Methodology and comparators

Slightly different from the approach that was applied in Task 1.3.4 under ownership models, in this memo, the Project Team focused on the change of staffing levels before and after a change in regulatory models.

As summarized in Figure 6, for the Outcomes-based PBR, the UK and Ontario were selected as examples since both have set up Outcomes-based PBR. Illinois, Alberta, and New South Wales of Australia were chosen for the Conventional PBR with Light HERA model.[41] Since there is no Hybrid model that currently exists in other jurisdictions, we looked at New York which is in the process of transforming to a similar hybrid model including both a distribution-focused platform as well as an Outcomes-based PBR. New York also has an ISO.

Figure 6. Staff-to-customers ratio in representative states with different regulatory models

Number of staff in relevant state agencies

	Status quo	Outcomes-based PBR			Conventional PBR with HERA Light				The Hybrid Model
	HI	UK	Ontario	Average	Malaysia	Alberta	NSW	Average	New York
PUC	65	834	178	506	301	57	151	170	525

Number of retail electric customers

	Status quo	Outcomes-based PBR			Conventional PBR with HERA Light				The Hybrid Model
	HI	UK	Ontario	Average	Malaysia	Alberta	NSW	Average	New York
Total	*506,216*	*28,000,000*	*5,111,254*	*886,304*	*8,204,328*	*1,750,000*	*3,437,167*	*773,356*	*2,781,568*

Number of staff : 100,000 customers

	Status quo	Outcomes-based PBR			Conventional PBR with HERA Light				The Hybrid Model
	HI	UK	Ontario	Average	Malaysia	Alberta	NSW	Average	New York
PUC	12.8	3.0	3.5	3.2	3.7	2.4	4.4	3.5	18.9

Notes: (i) staff numbers under DCA are excluded from this chart since comparable DCA does not exist in the UK, Ontario, and Malaysia and the staff numbers are not publicly available in Alberta, NSW, and New York. (ii) sources of these numbers are provided in corresponding sections below. (iii) 2016 numbers were used for all jurisdictions to be consistent with the available data in Hawaii.

[41] HERA currently does not exist in either Hawaii or other jurisdictions, so the Project Team focused on the analysis of conventional PBR only for this model.

Also, it is important to caveat that the management structure and staffing arrangement of the PUC and DCA are affected by many factors. The sample jurisdictions were selected based on their primary regulatory models, not on their comparability to the state of Hawaii in terms of the number of customers, the number of utilities, or level of policy sophistication. However, to make the number of staff comparable, the number of customers is used to calculate the staff-to-customers ratio (number of staff: 100,000 customers) in Hawaii and each representative state. As the numbers suggested in Figure 6, even with the same regulatory model, the size of regulatory agencies may vary.

It should be noted that the policy ambition and complexity also have a critical impact on the staffing needs. For instance, as shown above, New York has the highest staff-to-customers ratio among all the sample jurisdictions. The high ratio is driven by the ambitious energy and environment policy goals and various corresponding initiatives in its Reforming the Energy Vision ("REV") initiative.

5.2.1 Outcomes-based PBR

The UK and Ontario were selected as representative jurisdictions for the Outcomes-based PBR model, primarily due to the number of years of experience with PBR, as well as the characteristics of their PBR regimes. The Project Team found that given the UK's example, the staffing needs might increase due to the setup of Outcomes-based PBR; but based on Ontario's experience, the staffing needs might not change much.

The UK has extensive PBR experience spanning over two decades. In particular, the UK's "Revenue = Incentives + Innovation + Outputs" ("RIIO"), an example of outcomes-based PBR, was quoted in the Hawaii PUC's order on PBR as "*one of the best-known examples of PBR in practice*."[42] Further details such as the overview of the market, the regulatory framework, and the history of transition and recent developments in the UK can be found in Task 2.2.2 (Assessment of current markets under each regulatory model).

Similarly, Ontario was selected as a representative jurisdiction as it also employs an Outcomes-based PBR approach. As part of its PBR regime, the Ontario Energy Board ("OEB") established the Renewed Regulatory Framework for Electricity ("RRFE") in 2012. As per the OEB, "*[the RRFE] articulates the OEB's goal for an outcomes-based approach to regulation which aligns the interests of customers and utilities*."[43] As such, key principles include:

- "*the expectation for continuous improvement;*
- *robust integrated planning and asset management that paces and prioritizes investments,*

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[42] Hawaii PUC. *Instituting a Proceeding to Investigate Performance-Based Regulation* (Order No. 35411). Docket No. 2018-0088. April 18, 2018.

[43] "Handbook for Utility Rate Applications." *OEB*. October 13, 2016. <https://www.oeb.ca/oeb/_Documents/Regulatory/OEB_Rate_Handbook.pdf>

- *strong incentives to enhance utility performance;*
- *ongoing monitoring of performance against targets; and*
- *customer engagement to ensure utility plans are informed by customer expectations."*[44]

The OEB believes that emphasis on the results rather than the activities will better lead to alignment with customer preferences, enhanced distribution productivity, as well as the spurring of innovation.[45] With regards to outcomes, utilities are responsible for identifying outcomes that would be valuable to customers, and accordingly, explain how said outcomes would be achieved under its plans and proposed costs. The outcomes are then associated with performance metrics, determining whether the outcomes have been achieved or not.[46] The OEB has identified four categories of outcomes to be achieved through the framework, namely customer focus, operational effectiveness, public policy responsiveness, and financial performance.[47] The OEB has also established a set of performance metrics for electricity distributors in its Performance Scorecard; all other utilities (i.e., natural gas transmission and distribution, electricity transmission, and Ontario Power Generation ("OPG")) propose their own scorecard, similar to the one developed for distributors.[48]

5.2.1.1 PUC

United Kingdom

Generally, Ofgem's offices are organized by function; as such, the divisions cover not only electric utilities, but also natural gas utilities. The Hawaii PUC on the other hand also covers telecommunications utilities, as well as the transportation and water/wastewater industries.

As of March 2018, the UK's Office of Gas and Electricity Markets ("Ofgem") had 724 permanently employed staff (average number of full-time equivalent ("FTE") people employed).[49] This is significantly more employees than that of both the OEB and the Hawaii PUC.

[44] Ibid, page 2.

[45] Ibid, page 2.

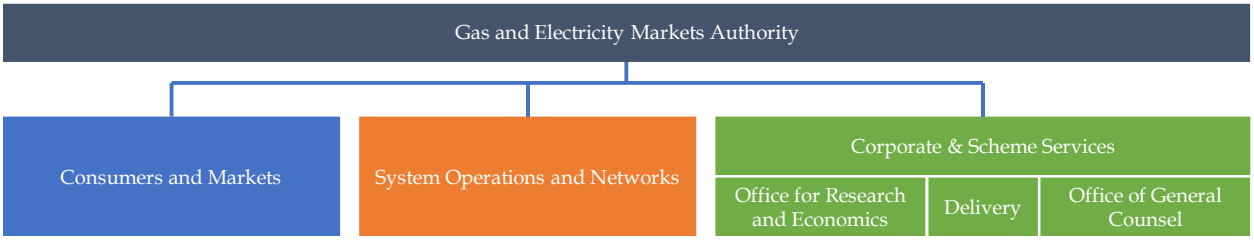
[46] OEB. *Handbook to Utility Rate Applications*. October 13, 2016. p. 15.

[47] Ibid, p. 15.

[48] Ibid, p. 16-17.

[49] Staffing levels post-organizational restructuring are lower than that of 2016 (i.e., 834 FTEs).

Figure 7. Ofgem organizational chart (post-structural reorganization)



Divisions	Function
Consumers and Markets	Looks after the interests of consumers in the energy market (wholesale and retail markets, enforcement)
System Operation and Networks	Focused on price controls (resources will particularly focus on the next round due to start in 2021) and ensuring maximum consumer benefits
Corporate & Scheme Services	Provides business support services and runs environmental schemes for Government

Note: The above divisions are for both the gas and electricity markets, and thus is representative of Ofgem as a whole.

Source: Ofgem, 2018.

Note: The above divisions are for both the gas and electricity markets, and thus is representative of Ofgem as a whole.

Source: Ofgem, 2018.

Ofgem underwent organizational restructuring in April 2018, reducing the number of divisions from seven to three to "*better focus on protecting consumers*."[50,51] The three divisions are comprised of Consumers and Markets, System Operation and Networks, and Corporate & Scheme Services. In turn, Ofgem and its divisions are governed by the Gas and Electricity Markets Authority ("GEMA"). The new organizational structure and its functions are depicted in Figure 7, while the number of staff and details regarding the background and expertise of the staff pre-reorganization are listed in Figure 8.[52]

[50] "Ofgem reorganization." *Ofgem.* January 15, 2018. Web. August 21, 2018. <https://www.ofgem.gov.uk/publications-and-updates/ofgem-reorganisation>

[51] Prior to organizational restructuring, Ofgem's divisions were comprised of the following: Corporate Affairs, Consumers and Competition, Energy Systems, Networks, Improving Regulation, Corporate Functions, and E-Serve. (Source: "New Ofgem organizational structure." *Ofgem.* January 12, 2016. Web. August 21, 2018. < https://www.ofgem.gov.uk/publications-and-updates/new-ofgem-organisational-structure>

[52] Details regarding divisional staffing (i.e. number of FTEs), are not available post-structural reorganization. This will likely be reflected in Ofgem's 2018-19 annual report (for the year ending March 31, 2019).

Figure 8. Number of staff members in each division of Ofgem and their major background/expertise (pre-structural reorganization)

Divisions	Approximate # of Staff	Major background/expertise of Staff
Regulatory	366	policy advisory, planning, administration
E-Serve	241	management, administration, development & implementation, operations
Corporate Services	117	management, budgets, risk management, finance, accounting, procurement

Note: Although prior to restructuring, Ofgem's divisions consisted of Corporate Affairs, Consumers and Competition, Energy Systems, Networks, Improving Regulation, Corporate Functions, and E-Serve, Ofgem's annual reports document divisional staffing numbers under the umbrella terms shown in Figure 8.

Source: Ofgem, 2018.

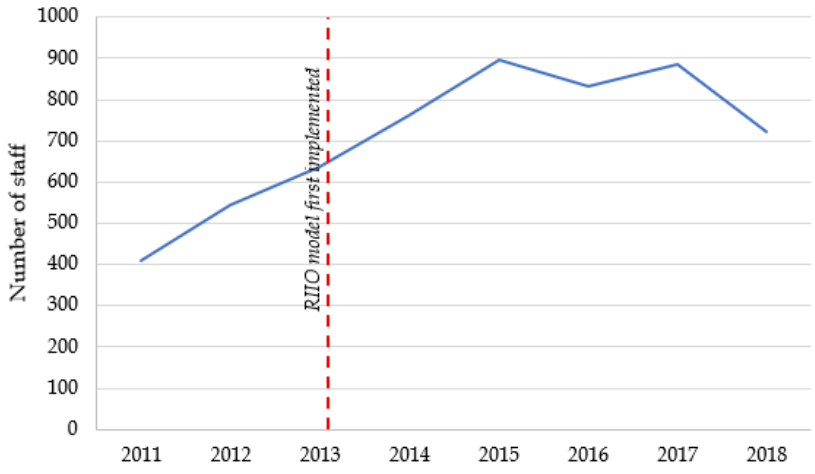
Ofgem's divisional structuring is more streamlined (i.e., has fewer divisions) than that of the Hawaii PUC. Nevertheless, both Ofgem and the Hawaii PUC have divisions dedicated to consumers (i.e., Consumer Affairs and Compliance in the Hawaii PUC and Consumers and Markets in the restructured Ofgem), a division dedicated to economics and research (i.e., Policy and Research in the Hawaii PUC and Office for Research and Economics sub-division under Corporate & Scheme Services in the restructured Ofgem) as well as an Office for Counsel (i.e., Commission Counsel in the Hawaii PUC and Office of General Counsel sub-division under Corporate & Scheme Services in the restructured Ofgem). Ofgem does not have a dedicated audit and engineering division, or an Office of the Commissioners as the Hawaii PUC does.

As can be seen, by the above numbers, Ofgem is significantly larger in terms of number of staff than the Hawaii PUC. Additionally, the Project Team notes that after the implementation of the RIIO in 2013, the number of staffing increased by 17% (from 545 in 2012 to 637 in 2013).[53] In the following year (2014), the number of staffing further increased by 19% to 761 staff, to be followed by another 18% increase in 2015 to 896 staff. The following year (2016) saw a decrease of 7% to 834 staff, only to increase again by 6% in 2017 to 886 staff.[54] Nonetheless, staffing levels decreased once again in the most recent year; in the year ending March 31, 2018, Ofgem had 724 permanently staffed FTEs, approximately 18% less than that of 2017. Overall, the adoption of the RIIO model has increased the number of staff in the UK for the first several years. Likewise, the implementation of the Outcomes-based model may result in a general increase in staffing members in the Hawaii PUC, if implemented.

[53] In addition, external experts were hired to help Ofgem with reviewing the PBR plans as well.

[54] The average number of staff decreased in 2015/2016, and the decrease was primarily "*concentrated in staff at the lower grades*." The reason for this decrease was not specified. (Source: Ofgem. *Annual Report 2015/16*.)

Figure 9. Ofgem's staffing levels before and after implementation of the RIIO model



Source: Ofgem annual reports 2010/11 – 2017/18.

Ontario

Like Ofgem, the OEB regulates both the natural gas and electricity sectors and similarly, divisions are organized by function. It does not cover telecommunications utilities or the transportation and water/wastewater industries as the Hawaii PUC does.

Similar to PUCs or PSCs in the US, the OEB acts as the energy regulator for Ontario. With the implementation of the PBR through RRFE in Ontario in 2012[55], the OEB staff's responsibilities increased and included the development of additional policies and processes pertaining to the RRFE, refine the scorecard, and develop additional incentive mechanisms.[56]

As per the *2018 to 2021 Business Plan*, the OEB has budgeted a staff headcount of 192 FTEs over the planning period, in addition to 11 FTE Board Members. Similar to Ofgem, the most recent staffing levels of the OEB are higher than that of the Hawaii PUC. The organizational structure is depicted in Figure 10, while the details regarding the background and expertise of the staff in each division are listed in Figure 11.[57]

[55] RRFE was first implemented in 2012, however PBR was first introduced in Ontario in 2007. Nonetheless, for the purposes of the regulatory model (i.e., Outcomes-based PBR), we will be focusing on the implementation of RRFE.

[56] OEB. *2014-2017 Business Plan.* < https://www.oeb.ca/oeb/_Documents/Corporate/OEB_Business_Plan_2014-2017.pdf>

[57] Details regarding divisional staffing (i.e. number of FTEs), are not available post-structural reorganization. This will likely be reflected in Ofgem's 2018-19 annual report (for the year ending March 31, 2019).

Figure 10. OEB organizational chart

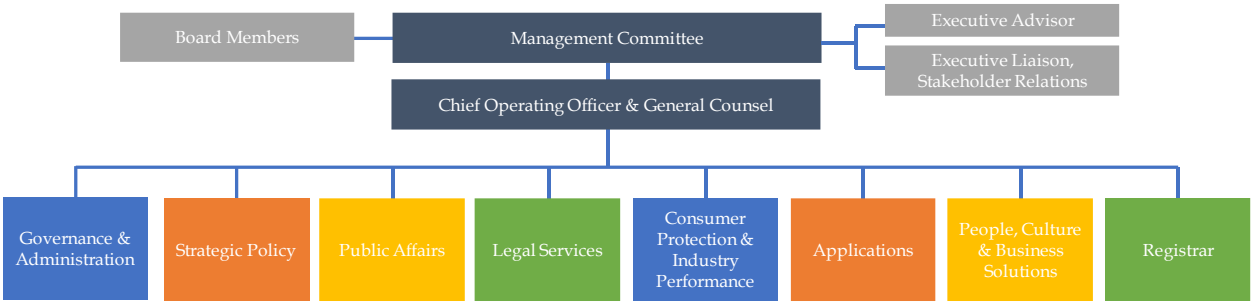


Figure 11. Divisions in OEB and major background/expertise of corresponding division's staff

Divisions	Major background/expertise of Staff
Management Committee	management, executive assistance
Chief Operating Officer & General Counsel	policy advisory, executive assistance
Governance & Administration	executive assistance, administration
Strategic Policy	strategic and policy advisory, risk management, business planning, executive assistance
Public Affairs	communications, media relations, stakeholder engagement, brand management
Legal Services	legal, strategic, and policy advisory, executive assistance
Consumer Protection & Industry Performance	management, customer assistance, auditing, licensing, compliance & enforcement
Applications	rates regulation, management, policy advisory
People, Culture & Business Solutions	human resources, finance, information technology, organizational development, procurement, facilities
Registrar	management, administration, policy advisory

Note: Staffing levels by division are not reported by the OEB.

Source: OEB.

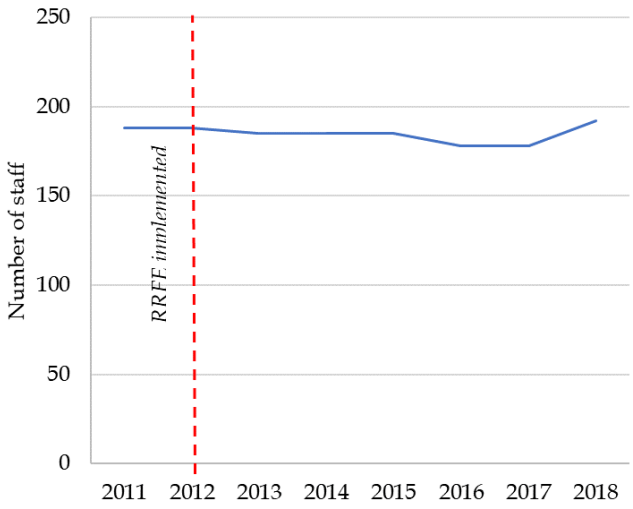
In addition to having higher overall staffing levels than the Hawaii PUC, the OEB also has more divisions. Overall, the OEB's divisional structuring is similar to that of the Hawaii PUC in the sense that both have a Commission-level committee (i.e., the Management Committee in OEB and the Office of the Commissioners in the Hawaii PUC), General Counsel divisions (i.e., Chief Operating Officer & General Counsel in OEB and the Commission Counsel in the Hawaii PUC), divisions dedicated to administration (i.e., Governance & Administration in OEB and Administrative Support Services in the Hawaii PUC), divisions dedicated to policy and research (i.e., Strategic Policy in OEB and Policy and Research in the Hawaii PUC), public relations divisions (i.e., Public Affairs in OEB and Consumer Affairs and Compliance in the Hawaii PUC), and human resource divisions (i.e., People, Culture & Business Solutions in OEB and Personnel Section in the Hawaii PUC).

Nonetheless, the OEB does not have a division dedicated to engineering and relevant analysis such as the Hawaii PUC's Engineering Section. The OEB also does not have a section performing auditing such as the Hawaii PUC's Audit Section; this activity is grouped along with customer assistance under the Consumer Protection & Industry Performance division. The Hawaii PUC,

on the other hand, does not have a department dedicated to legal activities such as the OEB's Legal Services division.

While division-level staffing numbers are not available, LEI notes that total staffing level has not been significantly impacted since the implementation of the Renewed Regulatory Framework for Electricity ("RRFE") in 2012. As seen in Figure 12, year-over-year staffing levels have ranged from -4% to 8% year-over-year from 2011 (before RRFE was implemented) to 2018. One plausible explanation for this is that the OEB hires consultants to help it with its review of the utility's proposals on PBR, and therefore, it does not need to hire additional full-time staff to work on this.

Figure 12. OEB's staffing levels before and after implementation of RRFE



Note: The above staffing levels are based on "budged headcounts" of full-time staff positions over different time periods, and thus the Project Teams assumes that these are indicative of actual staffing levels. The budgeted headcount for 2014 and 2015 was not provided in OEB's *2014-2017* and *2015-2018 Business Plans*, respectively. As such, the budgeted headcount for 2014 and 2015 was assumed unchanged from OEB's *2013-2016 Business Plan Package* (i.e., a full-time headcount of 185 positions). Budgeted headcounts were not available for years prior to 2011. The staffing levels do not account for the number of Board Members.

Source: OEB *Business Plan* reports, 2011-2018.

5.2.1.2 DCA

While both the UK and Ontario have independent organizations to represent the interests of consumers, these groups are not government agencies such as the DCA in the State of Hawaii. Nonetheless, a brief discussion of these groups and their functions is provided below.

United Kingdom

The UK does not have public consumer advocacy groups such as the DCA in the State of Hawaii. Instead, in the UK, consumer advocacy for energy is undertaken by two non-governmental organizations namely Citizens Advice and the Energy Ombudsman.

Citizens Advice holds the "*statutory role as the consumer advocate for energy consumers, to represent consumers across the energy industry*."[58] It is a national charity network comprised of approximately 300 independent local charities across England and Wales.[59] The charity organization not only advises and supports consumers regarding gas and electricity complaints, but also in other areas such as employment benefits, debt and money, consumer goods, family, housing, law and courts, immigration, and health.[60]

The Energy Ombudsman is also another Ofgem-approved independent organization that helps "*handle disputes between energy companies and their customers, which includes domestic customers and micro businesses*."[61] It is a free service that is generally utilized if an energy supplier has not settled the consumer's complaint.

Ontario

Similar to the UK, Ontario does not have a public consumer advocacy group such as the DCA in the State of Hawaii. Rather, the Consumers Council of Canada is a not-for-profit, voluntary organization that represents the interests of residential customers in Ontario with regards to not only energy-related matters but also in issues pertaining to housing; justice, resolution & redress; digital economy; and product performance & safety. The Consumers Council of Canada is a member of the Canadian Consumer Initiative under the Office of Consumer Affairs, Industry Canada,[62] and advocates for the Charter of International Consumer Rights.[63] As mentioned in Task 1.3.4 (Assessment of how each ownership model impacts staffing of State agencies and stakeholders), the Consumers Council of Canada comprised of thirteen Board of Directors (including a President, a Vice President, a Secretary, a Treasurer, eight Directors, and an Executive Director), with areas of expertise including, but not limited to, of law, auditing, economics, communications, consulting, and management.[64] While its function is similar to that

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[58] "Outcome of Ofgem price controls consultation "will be the acid test", says Citizens Advice." *Citizens Advice.* March 7, 2018. Web. August 22, 2018. < https://www.citizensadvice.org.uk/about-us/how-citizens-advice-works/media/press-releases/outcome-of-ofgem-price-controls-consultation-will-be-the-acid-test-says-citizens-advice/>

[59] Citizens Advice. *Annual report 2016/17.*

[60] "Welcome to Citizens Advice." *Citizens Advice.* Web. August 22, 2018. < https://www.citizensadvice.org.uk/>

[61] "About the energy ombudsman." *Ombudsman Services.* Web. August 22, 2018. < https://www.ombudsman-services.org/sectors/energy>

[62] Consumers Council of Canada. *About Us – Canadian Consumer Initiative*. Web. < https://www.consumerscouncil.com/index.cfm?pagePath=About_Us/Canadian_Consumer_Initiative&id=18300>.

[63] "About the Council." *Consumers Council of Canada.* Web. August 22, 2018. < https://www.consumerscouncil.com/about>

[64] Consumers Council of Canada. *Annual Report of Activities 2016 – 2017*. Page 50 – 54.

of the Hawaii DCA, the Consumers Council of Canada is not further divided into divisions/functional branches. This means that it only has one division doing all the work.

5.2.2 Conventional PBR with Light HERA

The second recommended model is a hybrid of Conventional PBR with Light HERA, as described in Task 2.2.6. Since HERA does not exist yet in Hawaii and there is no jurisdiction that has both Conventional PBR and a standalone entity (other than ISOs) that enforce reliability standards, this section focuses on jurisdictions that implemented Conventional PBR only. Moreover, as HERA is a separate entity outside of Hawaii PUC, the Project Team assumes that it would have limited impact on staffing of existing state agencies, including the PUC and DCA. The Project Team finds that the staffing numbers of relevant state agencies would increase once the Conventional PBR is implemented.[65]

Malaysia, Alberta, and New South Wales of Australia were chosen as examples because they all have Conventional PBR mechanisms in place and they are single-state or single-province jurisdictions which are more comparable to Hawaii than a country.

In Malaysia, the Conventional PBR is also called the incentive-based regulation ("IBR") which started in 2014. It applies to the Tenaga Nasional Berhad ("TNB"), the only electric utility company in Peninsular Malaysia. Revenue cap is used for transmission, system operator, and Single Buyer (operational), while pure price cap is used for customer services (i.e., distribution utilities). The Suruhanjaya Tenaga ("ST"), the energy regulator in Malaysia, used the building blocks approach to set the price. In addition, to facilitate the implementation of PBR, the ST takes the responsibilities of reviewing historical cost performance, testing efficiencies through benchmarking, recommending performance targets, etc.

In Alberta, ENMAX, a vertically integrated utility in Calgary, was the first transmission and distribution utility to propose PBR in the province before the Alberta Utilities Commission decided to introduce the approach to the other electric and natural gas distribution utilities in 2011. As an example of Conventional PBR, Alberta uses the I-X approach,[66] price cap (for electric distributors), and revenue cap (for electric transmission) together with other adjustments, such as the earnings sharing mechanism and offramps/reopeners. With the implementation of the PBR, the AUC reviews multiple regulatory submissions related to the PBR. These include the PBR plan and capital tracker filing, and many more. The PBR plans are also more comprehensive than the cost of service filings as the utilities need to submit back up their plans and proposals.

As for New South Wales ("NSW"), the National Electricity Rules ("NER") requires the implementation of an incentive-based regulatory regime in the form of a revenue cap or some incentive-based variant, which was designed to foster efficient investment and operating

[65] The staffing numbers in Illinois before and after the introduction of the Conventional PBR is not publicly available.

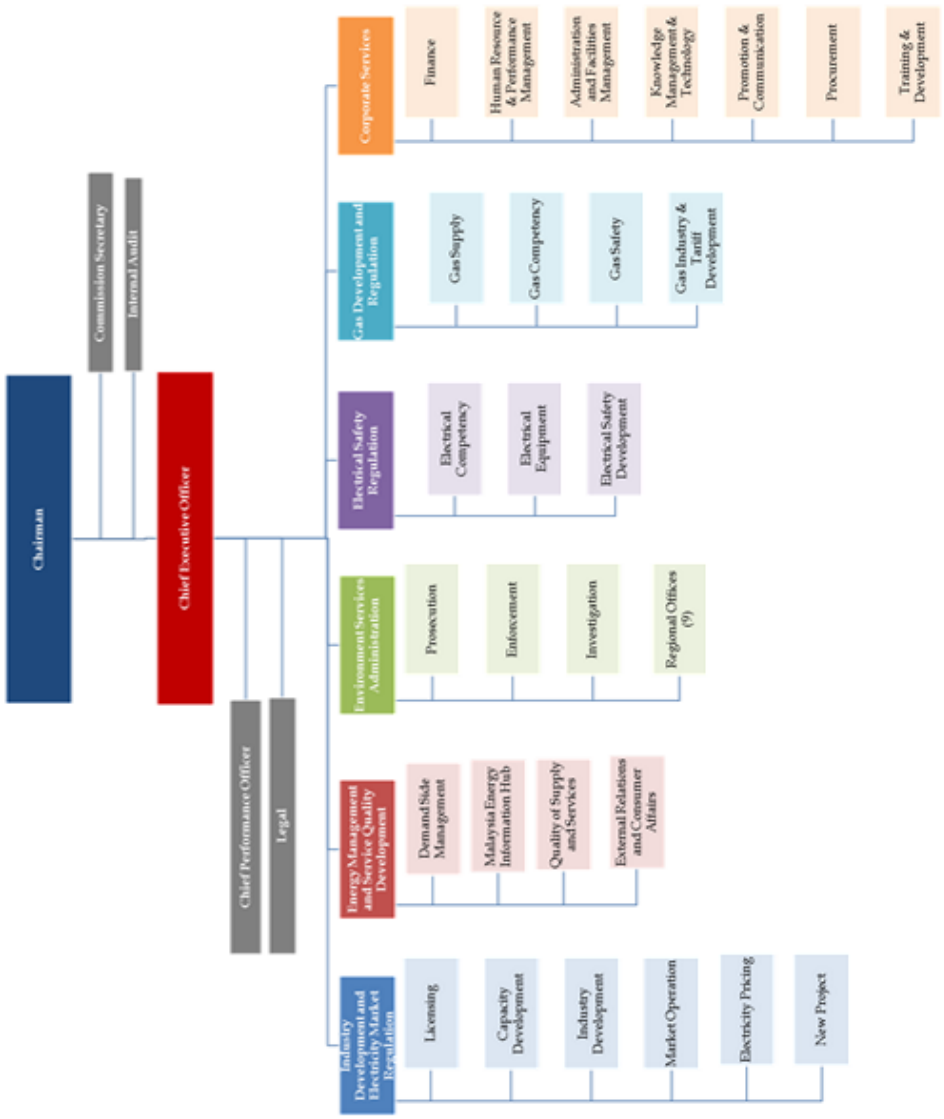
[66] In Alberta, "I factor" means blended input-based inflation factor based on a Canada-wide construction price index and a provincial wage index. Each index weight is 0.5 in distribution and transmission. "X factor" was approved based on a survey of historical Total Factor Productivity studies and other jurisdictions' practices.

practices and ensure the quality of service. In the NSW, transmission networks are regulated under weighted average price caps, using the building blocks approach. It also involves a symmetric earnings-sharing mechanism and off-ramps for transmission utilities. Similar to the other two examples mentioned above, the regulator in NSW had more responsibilities with the implementation of the PBR.

5.2.2.1 PUC

Malaysia

Figure 13. Organizational chart of Malaysia ST

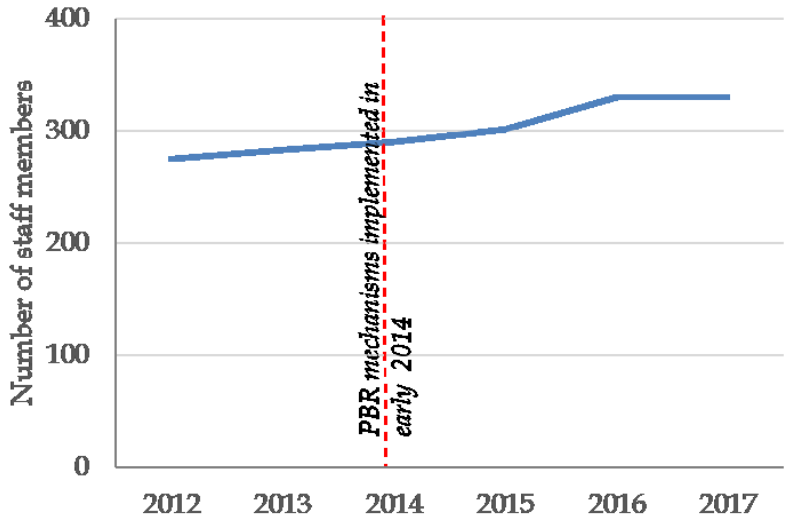


Source: Malaysia ST. Business Plan 2015-2020. December 2015. Page 25.

As discussed in Task 1.3.4, the Energy Commission or ST in Malaysia is a statutory body established under the Energy Commission Act 2001. Its primary responsibility is to regulate the energy sector, especially the electricity supply and piped gas supply industries in Peninsular Malaysia and Sabah.[67] As shown in Figure 13, the Chairman and Chief Executive Officers lead the ST. Staff is divided into six departments, including Industry Development and Electricity Market Regulation, Energy Management and Service Quality Development, Environmental Services Administration, Electrical Safety Regulation, Gas Development and Regulation, and Corporate Services.[68] Also, there are nine regional offices under the Environmental Services Administration department.

The PBR was introduced in early 2014 in Malaysia. In that year, the total number of employees in the ST increased by 2% from 283 to 290. In the following year (2015), the staffing number increased to 301.[69] Moreover, the total number is projected to increase over the next few years and will reach 350 by 2020.[70] Admittedly, other factors, i.e., the implementation of Single Buyer in 2014, could have contributed to this increase in staffing needs as well. More workload resulted from the PBR implementation implies that more staffing members may be required in the Hawaii PUC if a Conventional PBR model is implemented.

Figure 14. ST's staffing levels before and after PBR implementation



Source: Malaysia ST. Business Plan 2015-2020. December 2015.

[67] Malaysia ST. *Overview of the Energy Commission*. Web. <http://www.st.gov.my/index.php/en/about-us2/overview-of-the-energy-commission>.

[68] Malaysia ST. *Business Plan 2015-2020*. December 2015. Page 25.

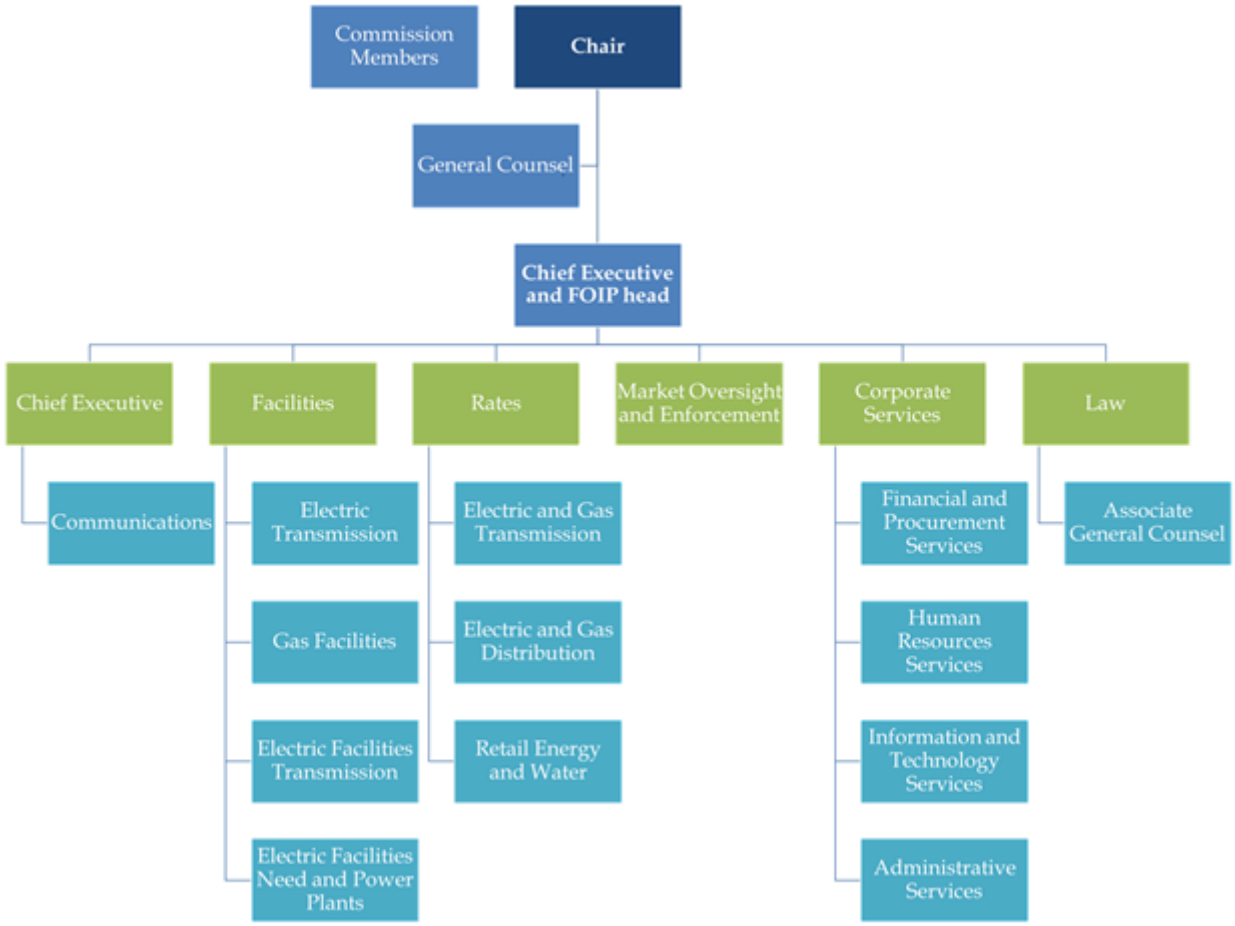
[69] Ibid, page 26.

[70] Ibid, page 26.

Alberta

The Alberta Utilities Commission ("AUC"), similar to the Hawaii PUC, regulates the investor-owned electric, gas, water utilities and certain municipally owned electric utilities in Alberta, Canada.[71] However, different from the Hawaii PUC, the AUC does not cover telecommunication utilities or transportation. As shown in Figure 15, in addition to the Chair, Commission Members, General Counsel, and Chief Executive, the AUC consists of six major divisions, namely Chief Executive, Facilities, Rates, Market Oversight and Enforcement, Corporate Services, and Law.

Figure 15. Organizational chart of the Alberta Utilities Commission



Note: FOIP – Freedom of Information and Protection of Privacy
Source: AUC. Organizational Chart. Web.
<http://www.auc.ab.ca/Shared%20Documents/AUCorganizationalchart.pdf>

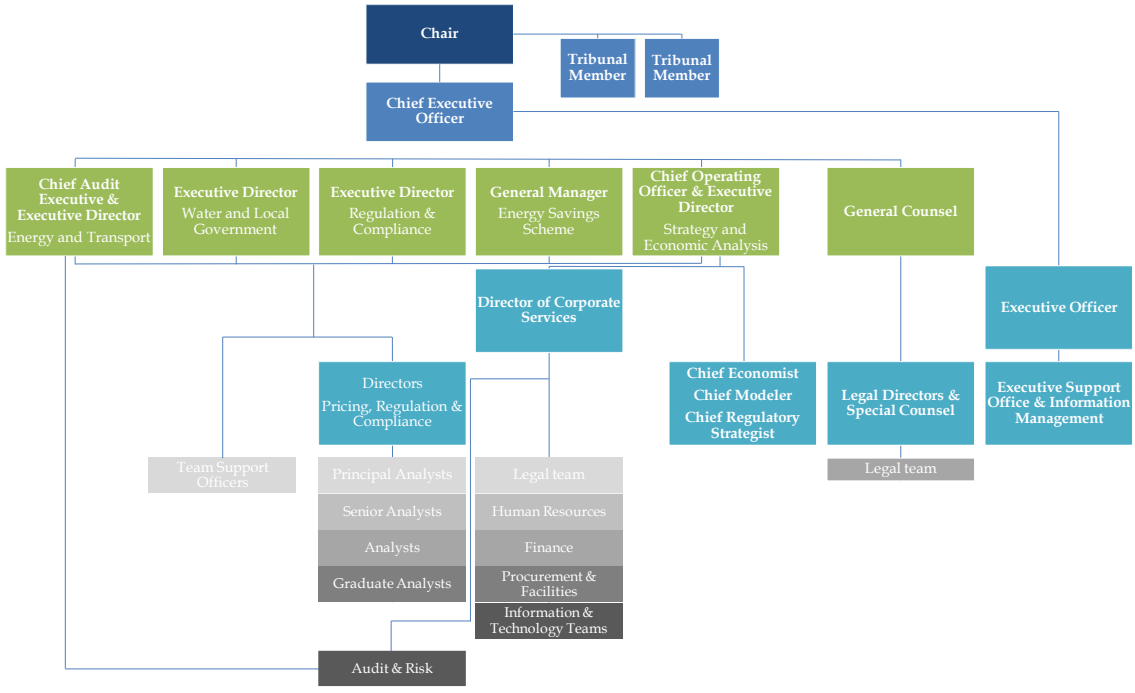
[71] "About us – who we regulate." *AUC*. Web. <http://www.auc.ab.ca/pages/who-we-regulate.aspx>. Access date: August 30, 2018.

There are around 60 employees in the AUC in the past three years (2015 – 2017),[72] but the numbers of employees in the years before the implementation of Conventional PBR are not publicly available.[73]

New South Wales

The Independent Pricing and Regional Tribunal ("IPART") is the provincial regulator responsible for the electricity, gas, water, and transport sectors, thereby serving the role of PUC in New South Wales. Unlike the Hawaii PUC, IPART does not regulate the telecommunications sector. More specifically, IPART is responsible for the economic regulation of transmission and distribution networks within New South Wales. Under the *Electricity Supply Act 1995*, IPART is also responsible for setting retail tariffs, as well as monitoring electricity licenses in distribution and supply. [74] Figure 16 depicts the divisional structure of the IPART, consisting of divisions dedicated to Energy and Transport, Licensing and Compliance, Water Pricing, and Local Government, to name a few.

Figure 16. Organizational chart of the Independent Pricing and Regional Tribunal



Source: IPART Annual Report 2016-17.

[72] Alberta PUC. *Compensation Disclosure*. 2015 – 2017.

[73] The Project Team has sent the data request to the department but has not heard back from them yet.

[74] NSW Government. Department of Premier and Cabinet. *Final Report of the Special Commission of Inquiry into the Electricity Transactions*. October 2011. p. 23.

The employment categories within the divisions, as well as the corresponding approximate number of staff and major background/expertise of said staff, are provided in Figure 17. While divisional staffing levels are not provided, Figure 16 shows that IPART has a division dedicated to compliance (i.e., Regulation & Compliance) like the Hawaii PUC (i.e., Consumer Affairs and Compliance). Both PUCs also have separate divisions for legal advisory (i.e., Commission Counsel in the Hawaii PUC and General Counsel in IPART), as well as for policy and economics research (i.e., Policy and Research in the Hawaii PUC and Strategy and Economic Analysis in IPART).

Unlike the Hawaii PUC, however, IPART does not have a separate division for audit (i.e., the Audit Section in the Hawaii PUC); instead, Audit & Risk fall under Energy and Transport, as well as under the Director of Corporate Service (which in turn is under Strategy and Economic Analysis). Also, unlike the Hawaii PUC, the IPART has divisions dedicated to sectors, such as the Energy & Transport division and the Water & Local Government division.

Figure 17. Number of staff members in the employment category of IPART in 2016 and their major background/expertise

Employment category	Approximate # of Staff	Major background/expertise of Staff
Chair	1	management
Chief Executive	1	management, operations
Executive Directors & General Managers	6	management, executive assistance, daily operations
Chief Financial Officer & Director, HR	2	human resource management, operations
Directors	16	management, daily operations
Managers	4	management, daily operations
Analysts	77	project support, technical assistance, research, analysis
Graduate Analysts	3	project support, technical assistance, research, analysis
General Counsel	1	policy advisory
Director, Legal & Special Counsel	2	legal advisory, policy advisory, planning
Legal Officers	3	legal assistance, policy advisory
Support Officers	23	technical assistance, administration, information technology
Supernumeraries	12	*N/A*
Total	***151***	***N/A***

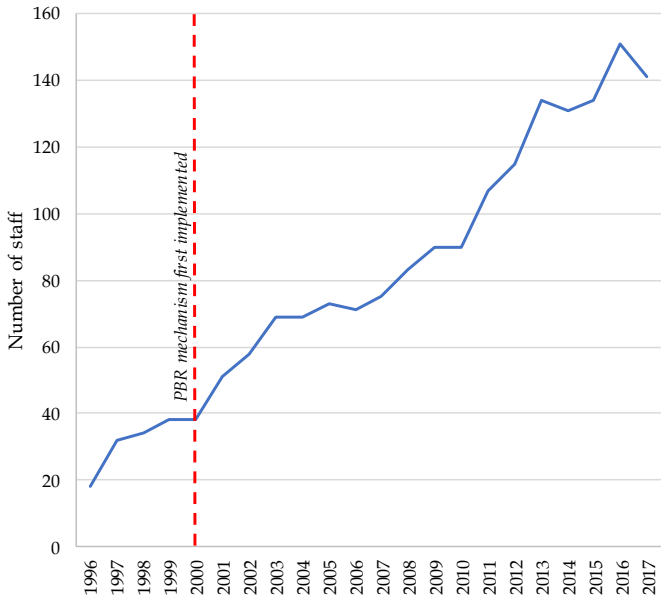
Note: The number of staff (i.e., a total of 151 employees) represent full-time, part-time, and temporary staff, as well as graduates. Tribunal members are not included.

Source: IPART Annual Report 2015-16.

As shown in Figure 17, IPART had a total of approximately 151 employees, including full-time, part-time, and temporary staff, as well as graduates in 2016 (not including Tribunal members), or 133 full-time equivalent employees.

The PBR mechanism for New South Wales was approved in 1999 and came into effect in 2000. As shown in Figure 18, the total number of staffing increased by 34% in 2001 (from 38 to 51), one year after the implementation of PBR. In 2002, the total staffing level increased further by 14% (from 51 to 58). Overall, total staffing levels have shown a generally increasing pattern since the adoption of PBR in 2000, with minor drops in 2006, 2014, and 2017, most likely due to retirements. This could mean that the implementation of the Conventional PBR with Light HERA model may increase the staffing levels required in the Hawaii PUC.

Figure 18. IPART's staffing levels before and after PBR signed into law



Note: The numbers above reflect the total headcount, not full-time equivalents. Put differently, the staffing level depicted above is comprised of full-time, part-time, and temporary staff, as well as graduates. Full-time equivalents are not provided in IPART Annual Reports prior to 2015.

Source: IPART Annual Reports (1995-2017)

5.2.2.2 DCA

Malaysia

Malaysia does not have a separate consumer advocate office. "*Balancing the needs of consumers and providers of energy*" and "*protecting public interest*" are parts of the mission of Malaysia ST.[75]

Alberta

Like the Hawaii DCA, the Office of the Utilities Consumer Advocate ("UCA") represents the interests of electricity and natural gas consumers in Alberta. The UCA is formed under the *Government Organization Act*, Schedule 13.1 and has three core functions, including education,

[75] Malaysia ST. *Vision, Mission and Core Values*. Web. <http://www.st.gov.my/index.php/en/about-us2/vision-mission-and-core-values>.

advocacy, and mediation.[76]The change in the number of staff members and their background/ expertise are not publicly available.[77]

New South Wales

The Energy & Water Ombudsman NSW ("EWON") is New South Wales' government-approved "*dispute resolution scheme*" for gas and electricity residential and small business customers, as well as some water residential and small business customers.[78,79] It was founded in 1998 as an independent service to help customers settle complaints with their respective providers. Both IPART and AER have signed a memorandum of understanding with EWON. In 2016/2017, EWON's structure was "*streamlined into four core teams working under the leadership of the Ombudsman*," namely People; Finance & Corporate Services; Investigations; and Governance, Awareness & Policy, as shown in Figure 19.[80] The number of staff members in EWON are not publicly available.[81]

Figure 19. Description of divisions and required expertise of staff members in EWON

Divisions	Description of Divisions	Major background/expertise of Staff
People	responsible for maximizing staff engagement and contribution, and develops HR strategy	human resources, development
Finance & Corporate Services	manages financial reporting, ICT infrastructure and service delivery, and general administraion and facility management	data analysis, information technology, finance, coordination
Investigations	handles customer complaints against providers, including receiving, assessing, investigating, and reviewing complaints	research, case review, assessment, resolution
Governance, Awareness & Policy	oversees governance, quality, member relations, communication, community outreach, and policy functions	policy, research, quality assurance, community engagement, communications

Source: EWON Annual Report 2016/2017

5.2.3 The Hybrid model

As discussed in the deliverables for Task 2.1.1 and 2.2.2, currently, no jurisdiction has a full-blown distribution-focused regulatory model. LEI focused on the example of New York since it is in the process of moving toward this model via REV. The REV initiative is aimed at fundamentally

[76] UCA. *Annual Report to the Minister 2016-2017.* October 16, 2017.

[77] The Project Team has sent the data request to the department but has not heard back from them yet.

[78] "About us." *Energy & Water Ombudsman NSW*. Web. September 6, 2018. < https://www.ewon.com.au/page/about-us>

[79] "Our History." *Energy & Water Ombudsman NSW*. Web. September 6, 2018. < https://www.ewon.com.au/page/about-us/our-history#founded>

[80] EWON. *Annual Report 2016/2017.*

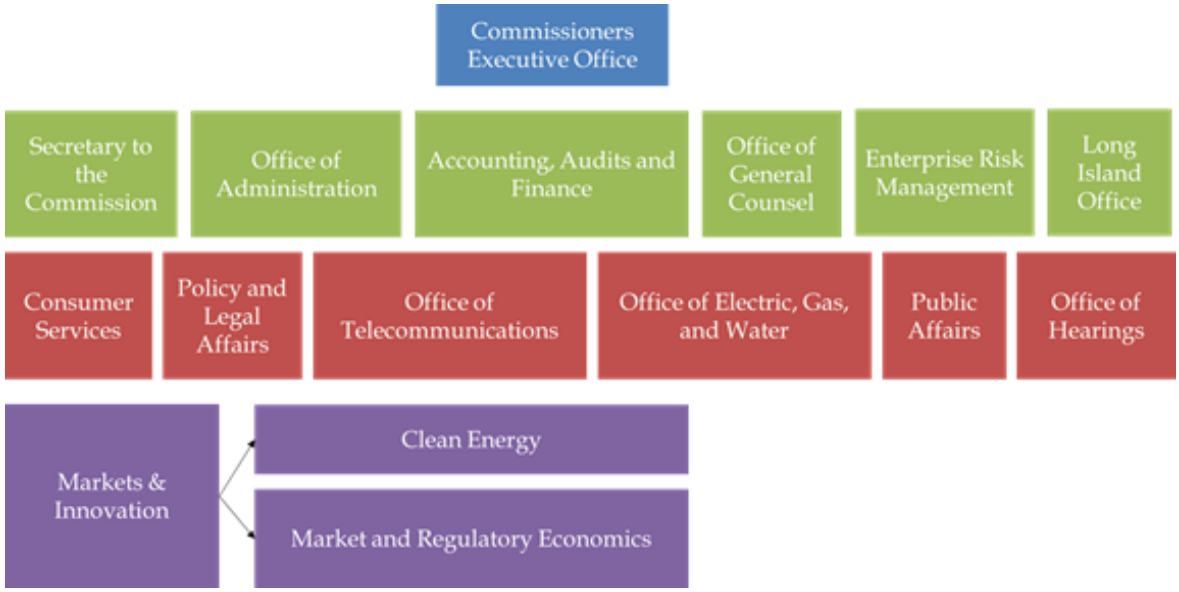
[81] The Project Team has sent the data request to the department but has not heard back from them yet.

shifting the role of the utility from an entity that develops and maintains transmission and distribution assets[82] to an entity that enables the localized management of electricity supply and demand. In addition, under REV, outcome-based earning opportunities will be added to the traditional ratemaking approach. Moreover, it has an ISO, which is similar to what is proposed for the independent grid operator. Admittedly, it is not the same as the Hybrid model that we proposed for Hawaii. However, this case serves as a good reference for assessing the impact of a similar hybrid model to the staffing of relevant State agencies. Further details such as the overview of the market, its regulatory framework, and the recent developments of REV in New York can be found in Task 2.2.2 (Assessment of current markets under each regulatory model).

5.2.3.1 PUC

Similar to the Hawaii PUC, New York Public Service Commission ("NY PSC") regulates the electric, gas, steam, telecommunications, and water utilities in the state. In addition, the PSC also oversees the cable industry. As the staff arm of the PSC, the Department of Public Service ("DPS") has a broad mandate to "*ensure access to safe, reliable utility service at just and reasonable rates*."[83] The DPS is organized into 14 offices, as shown in Figure 20.

Figure 20. Indictive organizational chart of New York PSC



Note: this chart is indicative only, as the official organization chart is not publicly available; color coding is added by LEI: green - departments dealing with PSC internal affairs, red - departments dealing with consumers or external entities, purple - departments highly related to regulatory changes
Source: NY DPS. Directory of Offices.

[82] Utilities in New York generally are not allowed to own generation assets.

[83] "About DPS." *NY DPS*. Web. <*http://www3.dps.ny.gov/W/PSCWeb.nsf/All/78F051A24B026591852576A5006D5163?OpenDocument*>. Access date: August 24, 2018.

These 14 offices have different functions and require staff to have different background and expertise. These background and expertise are listed in Figure 21. Similar to the Hawaii PUC, the NY PSC has separate divisions that are responsible for auditing, consumer affairs, administrative services, and policy and research, etc. In addition, the NY PSC has some sectors-focused divisions that the Hawaii PUC does not have, including the Office of Telecommunications and the Office of Electric, Gas, and Water. Moreover, some functional divisions that the NY PSC has also does not exist in the Hawaii PUC, like Enterprise Risk Management, Office of Hearings, and Markets & Innovation, to name a few.

It is worth noting that the Markets & Innovation division which focuses on clean energy and market oversight did not exist prior to 2014.[84] Its formation might be relevant to the REV initiative, while in Hawaii, the Hawaii State Energy Office takes the role of leading the state's change toward clean energy independence.[85] If the Hawaii PUC set up a similar division that focuses on the transition to the hybrid regulatory model, staff members that have experience with regulatory transitioning will be needed in this division.

Under REV, the NY PSC plays a critical role in crafting the significant regulatory changes needed to make the Governor's agenda a reality.[86] The NY PSC takes the responsibility of "*aligning markets and the regulatory landscape with the overarching state policy objectives of giving all customers new opportunities for energy savings, local power generation, and enhanced reliability to provide safe, clean, and affordable electric service*."[87] Under the REV proceeding (Case number 14-M-0101), there are approximately 1,500 filed documents, 7,800 public comments, and 290 stakeholders included in the party list.[88] In addition, under this proceeding, two REV working groups were set up under Track 1, and both of them were convened by the NY DPS staff together with stakeholders.[89] Obviously, the transition under the REV model increased the workload for the NY PSC

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[84] The Markets & Innovation division was not listed on the web page on NY DPS which was updated by September 2013. Source: NY DPS. Web. <*http://www3.dps.ny.gov/W/PSCWeb.nsf/All/78F051A24B026591852576A5006D5163?OpenDocument*>. Access date: August 24, 2018.

[85] "Who we are." *Hawaii State Energy Office*. Web. < http://energy.hawaii.gov/who-we-are>. Access Date: September 11, 2018.

[86] "About the Initiative." *New York State - DPS*. Web. <http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument>. Access Date: September 11, 2018.

[87] Ibid.

[88] "Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision." *NY PSC*. Web. <http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101&submit=Search+by+Case+Number>. Access Date: September 11, 2018.

[89] "Working Groups." NY DPS. Web. <http://www3.dps.ny.gov/W/PSCWeb.nsf/All/D437F88969CCD2F985257CD20066552A?OpenDocument>. Access Date: September 11, 2018.

significantly, and transition to a Hybrid model would potentially have similar impacts on the Hawaii PUC as well.

Figure 21. Description of divisions and required expertise of staff members

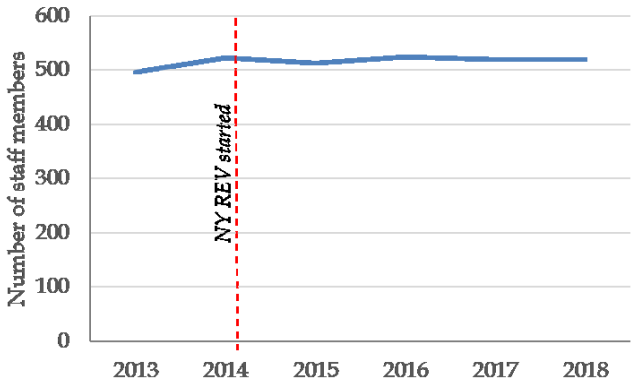
Divisions	Description of divisions	Major background/ expertise of Staff
Executive Office	senior management of the organization and relevant support	management, development, administration
Policy and Legal Affairs	special counsel and senior policy advisor regarding strategic planning; make recommendations to the Commission on policy, regulatory, and legal matters	expertise in policy, regulatory, and legal matters
Secretary to the Commission	maintaining the records of the proceedins with the DPS; coordination of the components of proceedings; etc.	administration, documentation, clercial services, knowledge of ethical responsibilities as employees, etc.
Public Affairs	an advocate for the utility regulatory policies, programs, and initiatives; an integrated internal and external communications program	communications, public relations
Long Island Office	examining the core utility operations of PSEG Long Island, and advising the Long Island Power Authority	operations of utilities
Office of Administration	consisting of three sections including the Human Resources Management section, the Administrative Management section, and the Finance and Budget section	recruitment, human resources, administrative management, fiscal, and budgeting
Consumer Services	representing consumer for all activities overseen by the Commission, taking and resolving consumer complaints and utilizing consumer input to develop consumer policy	consumer engagement, facilitation, and communications, etc.
Markets & Innovation	clean energy initiatives, market analytics and oversight	analysis, economics, research, project management, rate design, etc.
Enterprise Risk Management	identifying particular events or circumstances (risk and opportunities) relevant to the organization's objectives, assessing and addressing risks and opportunities, internal auditing	analysis, research, auditing and monitoring
Office of General Counsel	legal representation and advice; representing on behalf of the people of the state in all actions and proceedings, preparing proposed regulations and legislation, etc.	legal advisory, testimony
Office of Hearings	hearings, legal assistance, mediators in assisting parties in settlement negotiations	legal assistance
Office of Telecommunications	overseeing the performance of the telecommunication and cable television companies	knowledge about telecommunication systems, technical and safety standards
Office of Electric, Gas, and Water	focusing on utility rates and services	knowledge about utilities, system planning and operations, tariff and rates, transmission and generation siting, etc.
Accounting, Audits and Finance	performing financial audits and examinations relative to utility rate changes, mergers and acquisitions, fuel clause operations, prudence reviews, and state and federal tax changes	financial auditing, accounting

Note: staff number under each department is not publicly available

Source: NY DPS. Directory of Offices.

As shown in Figure 22, the number of staffing increased by 5% (from 496 to 523) in 2014 when Governor Cuomo initiated the REV, which might be part of the preparation for the REV. Since then, the total staffing level has not changed much in the past few years.[90] Moreover, in terms of staff level (instead of the ratio), the NY PSC already has around 500 staff members before the implementation of the REV, so the need of adding additional staff might be less significant than the Hawaii PUC which only has 65 staff members. This implies that more staffing members are required in the Hawaii PUC if the regulatory model in Hawaii will be changed to a Hybrid model that is similar to the REV in terms of complexity.

Figure 22. New York PSC's staffing levels before and after implementation of REV



Note: 2018 number was estimated by New York State in 2017

Source: NY DPS. Executive Budget (2013 - 2017)

5.2.3.2 DCA

Similar to Hawaii, there is a separate entity that advocates for consumers' interests before the PSC in New York. Under the Consumer Protection division of the Department of State in New York, there is a Utility Intervention Unit subdivision, which "*actively participates in proceedings concerning the availability, pricing, and quality of electricity and natural gas service*." Like the DCA in Hawaii, experts in this Utility Intervention Unit "*submits formal filings commenting on proposals by utilities or regulators*" and "*testify before the PSC in natural gas and electricity delivery rate proceedings involving major utilities*."[91] However, data of staffing members of this subdivision is not publicly available.[92]

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[90] "Public Service Department - Budget Highlights." *New York State*. Web. <https://www.budget.ny.gov/pubs/archive/fy17archive/eBudget1617/agencyPresentations/appropData/PublicServiceDepartment.html>. Access date: August 24, 2018.

[91] "Utility Intervention." *Department of State*. Web. <https://www.dos.ny.gov/consumerprotection/reports/energy_utility_intervention/index.html>. Access date: August 24, 2018.

[92] The Project Team has sent the data request to the department but has not heard back from them yet.

6 Appendix A: Scope of work to which this deliverable responds

Task 2.3.4 Assessment of how each ownership model impacts staffing of State agencies and stakeholders such as the Public Utilities Commission and the Consumer Advocate similar to analysis conducted in TASK 1.3.4. CONTRACTOR shall provide an estimate of the potential impacts a change in regulatory model may have on the expertise and staffing requirements of related State agencies and stakeholders (e.g., PUC, Consumer Advocate).

DELIVERABLE FOR TASK 2.3.4. CONTRACTOR shall provide its conclusions and all work to assess how the regulatory model could impact state agencies and stakeholders such as the Public Utility Commission and the Consumer Advocate, similar to the analysis conducted on ownership models in TASK 1.3.4. CONTRACTOR shall analyze best practices in terms of staffing and expertise at public utility commissions, state energy offices, consumer advocate offices, and other relevant state agencies across a broad array of jurisdictions. CONTRACTOR shall identify at least three to five jurisdictions for each regulatory model, with staffing at their relevant state energy agencies, including the utility commissions. CONTRACTOR shall utilize high-level data, such as total staffing, from websites or in annual reports, along with the results of interviews to understand specific expertise required. CONTRACTOR shall provide a written description of the analysis in MS Word, include an overview MS Excel table listing total staffing in each jurisdiction assessed, include a breakdown for functional expertise and show an average for each of the regulatory models. CONTRACTOR shall submit deliverable for TASK 2.3.4 to the STATE for approval.

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Revenue requirements forecasts under each regulatory model

working paper prepared by London Economics International LLC for the State of Hawaii with support from Meister Consultants Group

September 26, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals; this document, which responds to Tasks 2.5.1 and 2.5.3, is one of several working papers associated with that engagement. It provides a background on revenue requirement calculations under different regulatory models and how it informed the assumptions, inputs, and approach used by the Project Team to project the components that constitute revenue requirements under each regulatory model for each county.

Three different variants of Performance-based Regulation ("PBR") models resulted in the lowest projected revenue requirements on each of Honolulu, Hawaii, and Maui Counties. The key factors impacting revenue requirements in these counties are the utilities' allowed rate of return and the capitalization rate applying to total utility expenditures. For Kauai County, the differences between the four regulatory models considered were under 1%; a softer touch regulatory approach had the lowest expected revenue requirements.

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List of acronyms

Capex	Capital Expenditures
CFC	Cooperative Finance Corporation
COS	Cost of Service
DBEDT	Hawaii Department of Business, Economic Development, and Tourism
DSPP	Distributed System Platform Provider
ESM	Earnings Sharing Mechanism
HECO	Hawaiian Electric Company
HELCO	Hawaii Electric Light Company
HERA	Hawaii Electricity Reliability Administrator
IGO	Integrated Grid Operator
IOU	Investor-Owned Utility
IPP	Independent Power Producer
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company
O&M	Operations and Maintenance
Opex	Operating expenditures
PBR	Performance-based Regulation
PIM	Performance Incentive Mechanism
PPA	Power Purchase Agreement
PSIP	Power Supply Improvement Plan
PSR	Platform Service Revenue
PUC	Hawaii Public Utilities Commission
RAB	Regulatory Asset Base
ROE	Return on Equity
RPS	Renewable Portfolio Standards
RUS	Rural Utilities Service
T&D	Transmission and Distribution
TIER	Times Interest Earned Ratio
Totex	Total expenditures
USDA	United States Department of Agriculture
WACC	Weighted Average Cost of Capital

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1 Executive summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which responds to Tasks 2.5.1 and 2.5.3 in the project scope of work, provides an overview of the revenue requirement calculations in the accompanying MS Excel workbooks. It describes the conceptual framework behind revenue requirement calculations and differences between regulatory models that inform the Project Team's approach and assumptions used to project revenue requirements for each county through 2045 under each regulatory models. The various regulatory models considered were described in previous working papers[1] and included:

- status quo with increased oversight from a Hawaii Electricity Reliability Administrator ("HERA") entity or the "HERA model";
- different variants of Performance-Based Regulation ("PBR");
- Integrated Grid Operator ("IGO");
- Distributed System Platform Provider ("DSPP"); and
- Lighter regulation of the Kauai Island Utility Cooperative ("KIUC") by the Hawaii Public Utilities Commission ("PUC") or the "Lighter PUC regulation."

Based on the analyses conducted, the recommended regulatory models evaluated for Honolulu, Hawaii, and Maui Counties were:

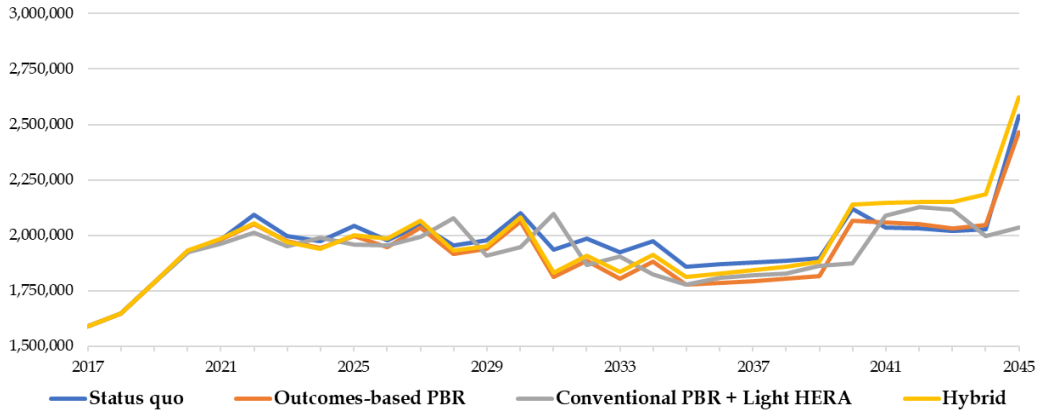
- Status quo or the current Cost-of-Service ("COS") model for an Investor-Owned Utility ("IOU") (this is the reference case),
- Outcomes-based PBR model,
- Conventional PBR + Light HERA model, and
- Hybrid model (combining Outcomes-based PBR, IGO, and DSPP).

The Project Team also assessed four separate regulatory models for Kauai County, namely, the status quo (co-op), Lighter PUC Regulation, HERA, and IGO models.

Using the approach and assumptions described below in Section 3.2, the Project Team estimated revenue requirements out to 2045 under the status quo for each county. Then, the Team calculated the revenue requirements for each county under the alternative regulatory models. The projections reflect the utilities' current capital costs and structure, planned capital spending on grid infrastructure, existing assets, resource plans, and current operating expenses, adjusted for expected changes in load, customers, and resource mix in the future.

[1] Such as Tasks 2.1.1, 2.2.1, and 2.2.6.

Figure 1. Honolulu County revenue requirements forecast by regulatory model ($000s, nominal)



Status quo	Outcomes-based PBR	Conventional PBR+Light HERA	Hybrid
NPV (2018-2045) at 7.57% - $ millions			
$22,410	$22,011	$22,023	$22,257
Revenue requirements growth (CAGR): 2018 - 2045			
1.61%	1.50%	0.78%	1.73%

Note: HECO's WACC (7.57%) was used as the discount rate to calculate NPV

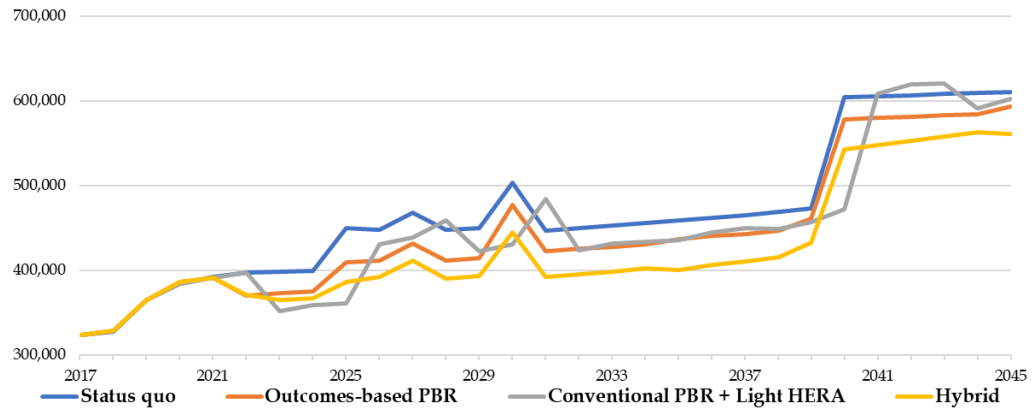
The projections for Honolulu County, as shown in Figure 1, result in increased revenue requirements under all regulatory models in the near-term, decreasing slightly until 2035, and growing again thereafter. The planned addition of 400 MW of offshore wind generation in both 2040 and 2045 contributes to the increase in projected revenue requirements for those years for all models. The planned biodiesel conversions of current diesel plants cause an even greater spike in 2045. Revenue requirements are forecast to be highest under the Hybrid model after 2040 because of additional costs associated with operating a DSPP.

Over the entire forecast horizon, revenue requirements forecast is highest in Net Present Value ("NPV")[2] terms under the status quo and lowest for the Outcomes-based PBR model, due to more consistent reductions in expenses relative to the status quo. In straight-average terms, the Conventional PBR + Light HERA model is forecast to have the lowest revenue requirements.

Similarly, Figure 2 shows that revenue requirements are projected to rise steadily in Hawaii County under all the regulatory models, with a spike in 2040 due to biodiesel conversion of utility-owned oil-fired generation units. Projected revenue requirements are highest under the status quo model than the other regulatory models for most years between 2020 and 2040. Overall, in NPV terms, the status quo has the highest forecast revenue requirements, and the Hybrid model has the lowest due to the impact of Earnings Sharing Mechanisms ("ESMs"). In each regulatory period, the projected excess earnings from the prior regulatory period are shared with the customers, thus lowering the final revenue requirements.

[2] Net Present Value represents the present value (as of 2018) of the revenue requirements over the entire forecast horizon. Revenue requirements for future years are discounted at a discount rate – the utility's cost of capital – to account for the time value of money.

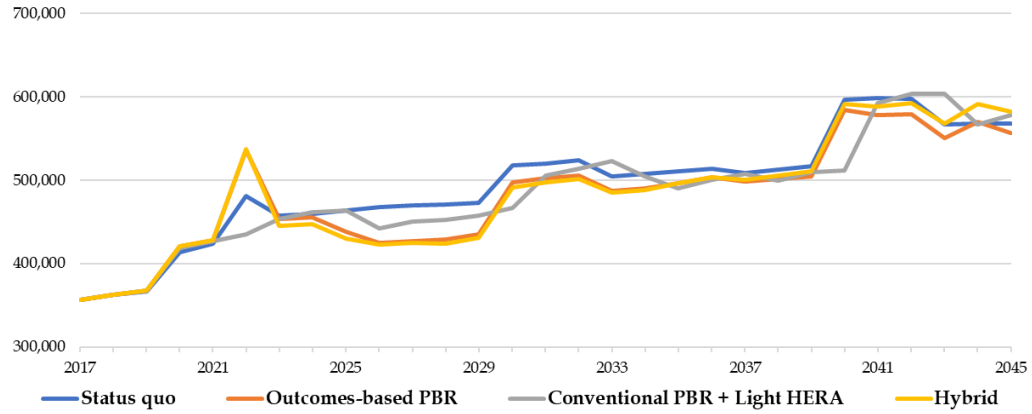
Figure 2. Hawaii County revenue requirements forecast by regulatory model ($000s, nominal)



Status quo	Outcomes-based PBR	Conventional PBR+Light HERA	Hybrid
NPV (2018-2045) at 7.79% - $ millions			
$4,870	$4,650	$4,659	$4,477
Revenue requirements growth (CAGR): 2018 - 2045			
2.33%	2.22%	2.27%	2.00%

Note: HELCO's WACC (7.79%) was used as the discount rate to calculate NPV

Figure 3. Maui County revenue requirements forecast by regulatory model ($000s, nominal)

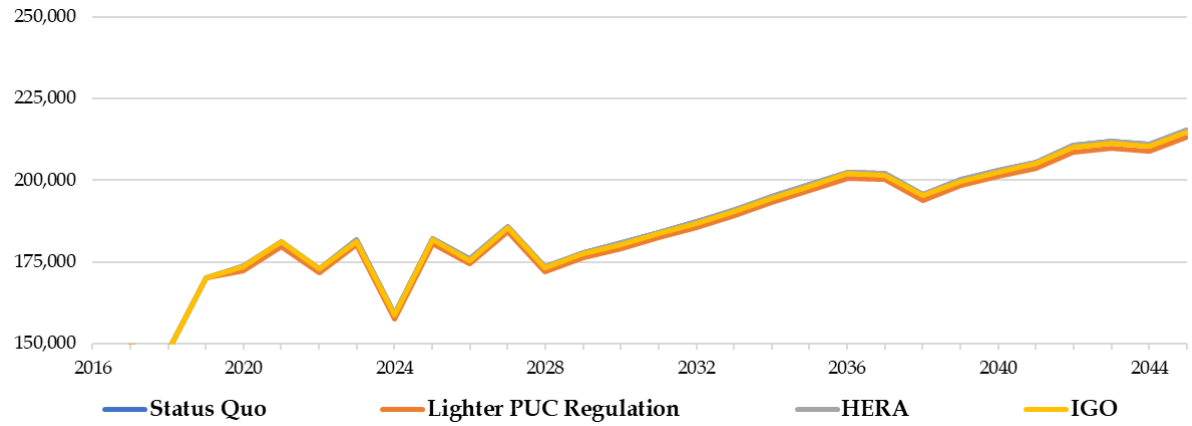


Status quo	Outcomes-based PBR	Conventional PBR+Light HERA	Hybrid
NPV (2018-2045) at 7.43% - $ millions			
$5,438	$5,330	$5,326	$5,319
Revenue requirements growth (CAGR): 2018 - 2045			
1.68%	1.59%	1.74%	1.77%

Note: MECO's WACC (7.43%) was used as the discount rate to calculate NPV

The revenue requirements in Maui County are also expected to increase until 2040 and stabilize subsequently under all regulatory models. Over the entire forecast horizon, the Conventional PBR + Light HERA model has the lowest revenue requirements forecast, which can be attributed to the revenue cap and a more limited set of Performance Incentive Mechanisms ("PIMs") compared to the other two alternative regulatory models.

Figure 4. Kauai County revenue requirements forecasts by regulatory model ($000s, nominal)



Status quo	Lighter PUC Regulation	HERA	IGO
NPV (2018-2045) at 5% - $ millions			
$2,722	$2,701	$2,722	$2,717
Revenue requirements growth (CAGR): 2018 - 2045			
1.40%	1.36%	1.40%	1.39%

Note: KIUC's cost of debt was rounded up to 5% for the discount rate to calculate NPV

The revenue requirements in Kauai County are projected to grow under all regulatory models in the short-term, fluctuate between 2021 and 2029, and increase again afterwards under all four regulatory models. These trends are primarily driven by capital expenditures and reductions in power supply expenses (fuel and purchased power). The difference in revenue requirements forecast under all three alternative regulatory models relative to the status quo is expected to be under 1% throughout the forecast horizon. This is because the additional costs due to the change in the regulatory models are small relative to the overall expenditures (capital and operating and maintenance costs).

In summary, for Honolulu, Hawaii, and Maui Counties, revenue requirements are expected to be highest under the status quo model. The three recommended models each result in the lowest projected revenue requirements in one county:

- Outcomes-based PBR on Honolulu County;
- Hybrid model on Hawaii County; and
- Conventional PBR + Light HERA model on Maui County.

For Kauai County, Lighter PUC Regulation results in the lowest revenue requirements and the HERA model in the highest.

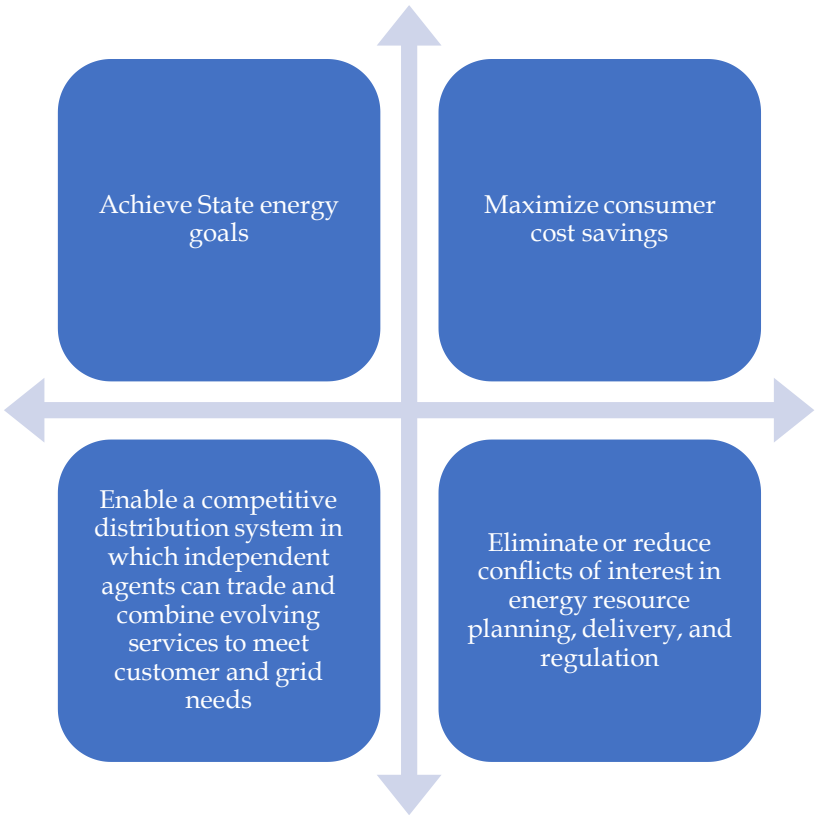
2 Introduction and scope

2.1 Project description

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission on a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[3] was contracted to perform this study.[4]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[5] listed in Figure 5.

Figure 5. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

[3] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[4] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[5] House Bill No. 1700 Relating to the State Budget.

The study will help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[6]

2.2 Role of this deliverable relative to others in the project

This deliverable is responsive to Tasks 2.5.1 and 2.5.3 in the project scope of work. It projects revenue requirements out to 2045 for the three Investor-Owned Utilities ("IOUs") in the State of Hawaii under four regulatory models as described previously in Task 2.2.1:

- status quo (the COS model),
- an Outcomes-based PBR model,
- a Conventional PBR + Light HERA model, and
- a Hybrid model.

The Project Team also evaluated four separate regulatory models for Kauai County:

- the status quo (cost-of-service under cooperative utility or "co-op"),
- Lighter PUC Regulation,
- HERA model, and
- IGO models.

This report discusses the components and calculations of revenue requirements under different regulatory models. Based on this discussion, the Project Team developed financial models to project revenue requirements. The analysis was conducted at a county level and is included in the accompanying MS Excel workbooks.

The Project Team conducted a thorough review of utility rate case filings, regulatory filings, public reports and statements, and various industry publications and data sources to collect the data and derive assumptions necessary for the revenue requirement calculations.

2.3 Future refinements

As noted earlier, this deliverable is subject to further refinement and modification as the project moves forward and as we receive feedback from DBEDT.

[6] Hawaii Contract No. 65595. Scope of Services.

3 Revenue requirements

The different regulatory models vary in terms of accompanying mechanisms, risks, targets, rewards, and penalties. The ability of each regulatory model to achieve various policy goals and performance targets have been discussed before in previous working papers. This report provides a comparison of revenue requirements forecast under different regulatory models and helps to quantify the appropriate level of compensation for the utility for its services under four regulatory models.

3.1 How are revenue requirements set under each regulatory model?

Regulatory models include different mechanisms that can impact revenue requirement calculations. For this analysis, the Project Team analyzed three different regulatory models in addition to the status quo for each of the four counties. The approach and calculations conducted for this analysis were similar to those performed to forecast revenue requirements under ownership models in Task 1.6.1. There are no fundamental changes in assumptions except for the PBR mechanisms. There are some additional administrative expenses due to PBR, some reductions in operating expenses, and fees for the new entities like Light HERA and IGO. Essentially, revenue requirements calculations under the various regulatory models represent additional features and components "bolted on"[7] to the underlying calculations in the status quo models. The underlying IOU structure of the HECO Companies and the co-op model of KIUC affected both the choice of recommended regulatory models and the revenue requirement calculations. This section provides an overview of the revenue requirement calculations under each model; specific assumptions used in the calculations are provided in Section 3.2.

3.1.1 IOU

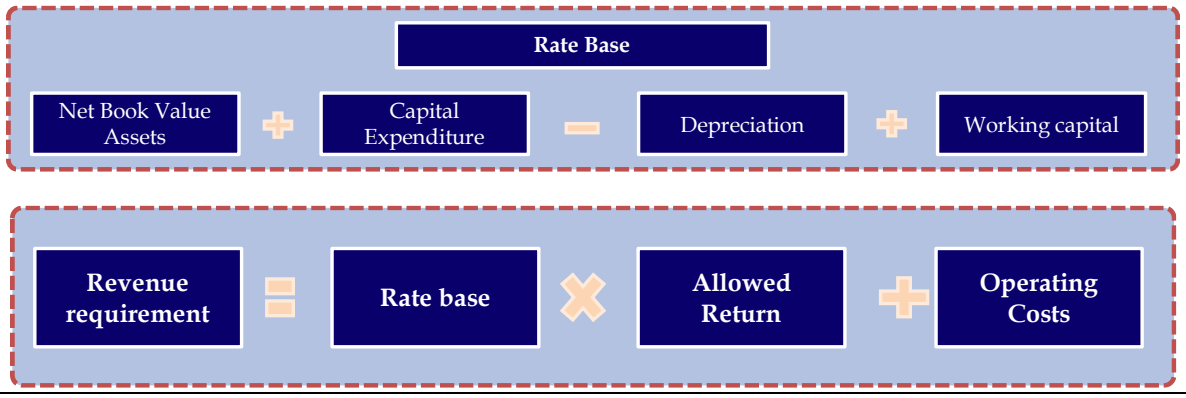
3.1.1.1 Status quo

There are three key components of the revenue requirements for an IOU: (i) the Regulatory Asset Base ("RAB"), (ii) the allowed rate of return, and (iii) operating costs. The RAB consists of investments made by the utility in various physical assets and infrastructure necessary to provide electric service on which the utility is allowed to earn a fair rate of return. The allowed rate of return is based on the utility's Weighted Average Cost of Capital ("WACC"), which is itself based on the weighted average cost of debt and equity faced by the utility. The different approaches that can be used to obtain the cost of debt and equity, as well as the appropriate capital structure for the utility, are typically explored in detail during rate case proceedings by the utility, the PUC, as well as other intervenors. Finally, operating costs such as fuel, power supply, tax, and other operations and maintenance ("O&M") expenses of the utility are typically passed through to the ratepayers; IOUs do not earn a return on these expenses under the standard cost-of-service

[7] Bolt-on technology refers to a new software or hardware that can be seamlessly integrated with an existing underlying system. Here, the term bolt-on is used strictly from a financial modeling standpoint. Revenue requirements for the recommended regulatory models are calculated by adjusting the model for the status quo to account for the additional costs and changes in underlying expenses due to PBR, Light HERA, and IGO. In practice, the changes would be more bottom-up – changes in investments and expenditure under the new regulatory models would result from utilities adjusting individual components of resource and capex plans.

ratemaking paradigm. A more detailed description of revenue requirement determination for IOUs can be found in the Task 1.6.1/1.6.3 report and are summarized below in Figure 6.

Figure 6. Rate base and revenue requirement formulae for IOUs



3.1.1.2 Outcomes-based PBR

Under an Outcomes-based PBR model, the outcomes and performance targets to be achieved by the utilities over a regulatory period (the term of which is part of the regulatory framework) are set during rate case proceedings. The Project Team assumes a regulatory period of 5 years for Outcomes-based PBR. The regulatory framework also includes incentives (both rewards and penalties) to achieve the targeted performance levels. Utilities are incented through both PIMs and ESMs. Revenue requirements under this model will be determined using a combination of a total expenditure ("totex") approach, PIMs, and ESM. A simplified graphical summary of revenue requirement calculations under this model is shown in Figure 9.

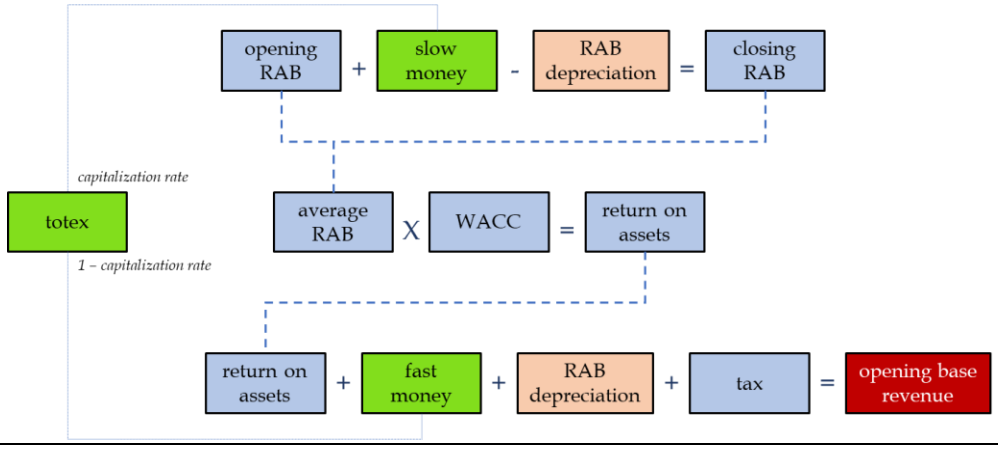
Totex approach

Under the traditional COS approach, only capital expenditures ("capex") can expand the utilities' RAB and allow them to increase their returns. Under a totex approach used by the UK's RIIO model and also used in this Study, instead of actual operating expenses ("opex") being passed through to ratepayers and actual capex added to the RAB, a set proportion of totex is funded through rates in the year incurred, called "fast money," and the remainder is added to the RAB and funded over time similar to capex, called "slow money." Fuel costs and expenses on Power Purchase Agreements ("PPAs") are not included in totex but passed through to ratepayers. The share of totex that constitutes slow money is determined by the totex capitalization rate, which is typically set at the beginning of the regulatory period based on the historical and forecasted split between capex and opex. Therefore, this rate can vary significantly between utilities as they do not have the same split between capex and opex.

Furthermore, utilities submit their forecast totex during the PBR proceeding and actual totex every year. They are also allowed to retain half of the amount they underspend as long as the underspend is due to efficiencies and that the outcomes agreed during the PBR proceeding are met. This means that the utilities cannot keep any underspends due to projects that did not materialize, or targets not achieved. At the end of the regulatory period, the PUC will review if the utilities have met the outcomes that they proposed at the start of the PBR regulatory period.

By splitting both capex and opex into slow and fast money as well as allowing utilities to keep the amount they underspend, the totex approach encourages utilities to use the most cost-effective solution. The totex approach eliminates the issue of favoring capex options if opex provides a better alternative. Figure 7 provides a graphical representation of how base revenues are calculated under the totex approach.

Figure 7. Base revenues under the totex approach



Additional O&M expenditure under the Outcomes-based PBR model would also include the costs incurred in filing capital and asset management plans, administration of PIMs, and retaining consultants in PBR-related proceedings.

PIMs

While additional and more detailed studies are necessary to evaluate the appropriate performance targets for the utilities, the Project Team has drawn up a potential list of performance measures. The assumed set of PIMs, or the rewards and penalties for each measure, for this regulatory model, is listed in Figure 8. Rewards and penalties for PIMs are based on whether utility performance falls outside the upper and lower bound targets for each PIM. If the actual performance falls short of the lower bound target, a penalty would be imposed for some of the PIMs; utilities are similarly rewarded for exceeding the upper bound target. If actual performance lies between the lower and upper bound targets, no penalty or incentive would be levied. The potential rewards and penalties are also capped, primarily to ensure the utilities' financial viability and to limit price volatility.

Figure 8. Potential outcomes and performance categories for Outcomes-based PBR

Performance outcome	Performance categories	Performance measures
Enhance customer experience	Customer satisfaction	• Billing accuracy • First contact resolution
	Service quality	• Telephone calls answered on time • New customers connected on time
	Customer engagement	• Number of consultations conducted
	Availability	• Generation availability • Equivalent forced outage factor • Equivalent forced outage factor demand
Improve utility performance	Reliability	• SAIFI • SAIDI • Number of times that power to a customer is interrupted
	Safety	• Number of general public incidents
	Cost control	• Cost of final delivered energy to customers by rate class for each island system • Total cost per customer • Total cost per km of wires
	Asset management	• Transmission plan implementation progress • Distribution plan implementation progress
Receptive to public policies and goals	Connection of renewable generation	• Number of renewables connected on time
	Connection of DERs	• Number of DERs connected on time
	RPS target	• Percentage of renewables relative to total energy
	Demand response implementation	• Amount of demand response implemented
	Competitive procurement	• Timely conduct of a competitive procurement • Cost savings in renewable generation procurement
Healthy financial performance	Financial ratios	• Leverage: total debt to equity ratio • Liquidity: current ratio (current assets/current liabilities)

ESMs

The Outcomes-based PBR would also feature a symmetric ESM applied to overall utility earnings. The ESM would be applied to the utility's Return on Equity ("ROE") if it exceeded or fell short of the authorized level of ROE. ESMs typically feature a deadband – a set margin around the allowed ROE that would not result in any sharing of earnings. However, if actual ROE is above the upper bound of the deadband, the excess earnings are shared with the customers in pre-determined percentage.

ESM calculations – hypothetical utility

Rate base: $2,000; Leverage ratio: 50%; Equity's share of rate base: $1,000
Allowed ROE: 10%; Deadband: +/- 100 basis points

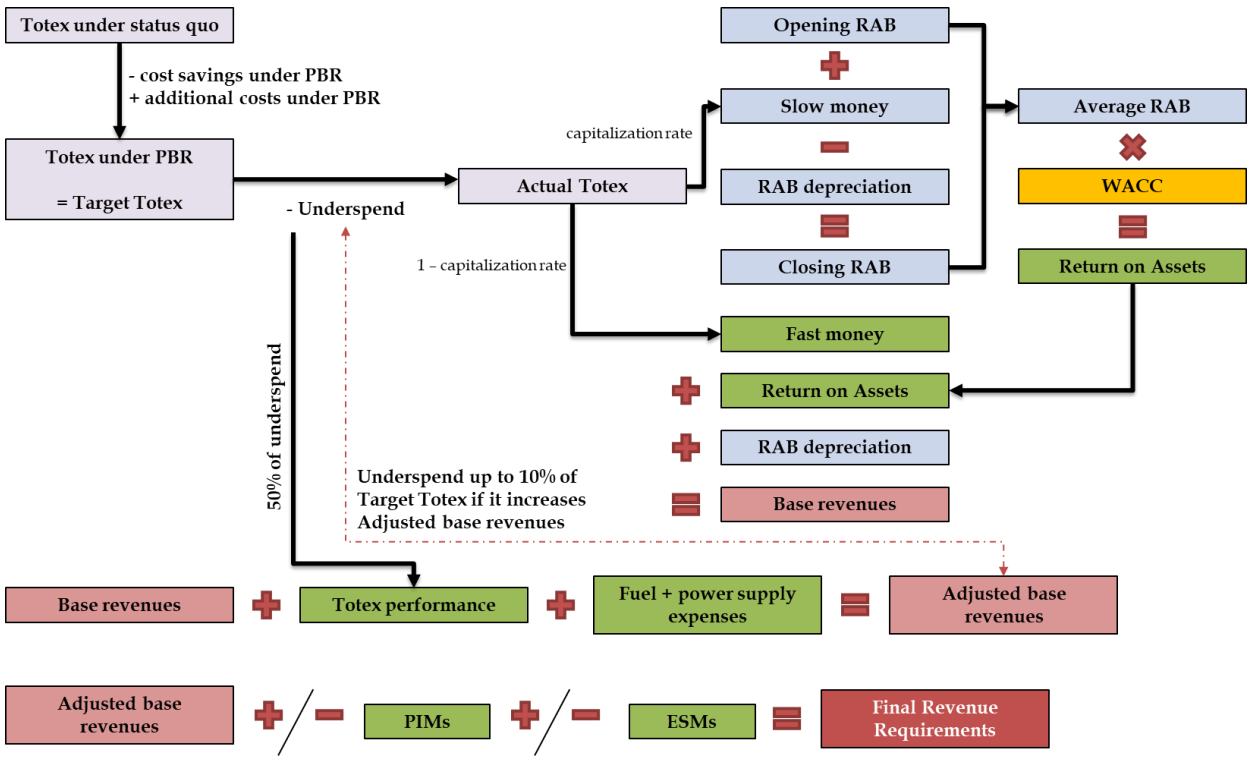
Net Income associated with allowed ROE: 10% X $1,000 = $100
Net Income within deadband (no ESM): $90 - $110 (ROE of 9% to 11%)

ESM – excess earnings if Net Income > $110 = actual Net Income - $110
ESM – insufficient earnings if Net Income < $90 = actual Net Income - $90

Similarly, if earnings are insufficient, the same percentage is collected from ratepayers in the subsequent regulatory period. The Project Team has assumed a deadband of 100 basis points

above and below (200 basis points in total) the allowed ROE. An illustrative example of ESM calculations is shown in the text box above.

Figure 9. Revenue requirements calculations under Outcomes-based PBR



Note: A higher level of underspend would allow the utility to increase its totex performance earnings but also lower the base revenues due to reduced fast money and slow money. The Project Team assumes that the utility optimizes the level of underspend relative to target totex to maximize adjusted base revenues. For modeling purposes, the Project Team believes that the utility is only able to lower actual totex from its target level by a maximum of 10% per year without disrupting its essential functions. The ESMs included in the final revenue requirements for a given year reflect the excess/insufficient earnings from the previous regulatory period, spread over the current regulatory period.

3.1.1.3 Conventional PBR + Light HERA

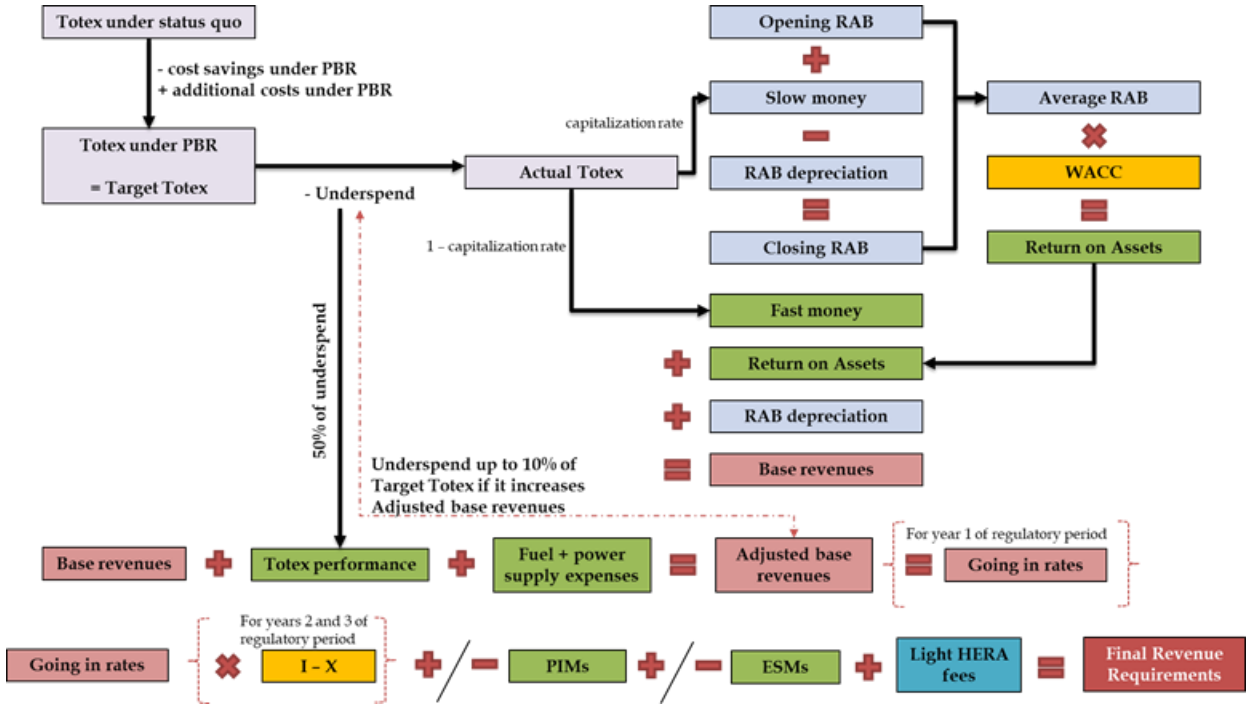
The Conventional PBR component of this model is different from the Outcomes-based PBR in a few key areas:

- a shorter regulatory period (3 years instead of 5 years);
- no requirement to file capital and asset management plans;
- fewer PIMs; and
- implementation of a revenue-cap approach.

Similar to Outcomes-based PBR, mechanisms such as totex, totex performance, pass through of fuel and PPA costs, PIMs, and ESMs are the same under the Conventional PBR; however, the PIMs under this model are less extensive. The target totex was set at the planned level of totex for that year under the status quo, adjusted for changes in costs under PBR. Once the base rates were obtained using the totex approach, the Project Team calculated the revenue-cap using an indexing

formula based on subtracting expected productivity growth from Hawaii's projected inflation rate (the "I-X" approach). The projected base rate for the start of the regulatory period was used as the going-in rate and adjusted for the remainder of the regulatory period using the indexing formula. The final revenue requirements were calculated by adding PIMs, ESM, and Light HERA costs to the going-in rates. A summary of revenue requirement calculations under the Conventional PBR + Light HERA model is depicted in Figure 10.

Figure 10. Revenue requirements calculations under Conventional PBR + Light HERA



Note: The figure represents a general case for calculations. For the first year of a regulatory period, adjusted base revenues is taken as the going in rate. For subsequent years in that regulatory period, the going in rate is increased/decreased by (I – X) after each year.

Compared to the Outcomes-based PBR model, the Conventional PBR has fewer list of PIMs as shown in Figure 11.

Figure 11. Potential performance categories and measures under Conventional PBR

Performance categories	Performance measures
Availability	• Generation availability • Equivalent forced outage factor • Equivalent forced outage factor demand
Reliability	• SAIFI • SAIDI • Number of times that power to a customer is interrupted
Cost control	• Cost of final delivered energy to customers by rate class for each island system • Total cost per customer • Total cost per km of wires
Service quality	• Telephone calls answered on time • New customers connected on time
Customer engagement	• Number of consultations conducted
Competitive procurement	• Timely conduct of a competitive procurement • Cost savings in renewable generation procurement
RPS target	• Percentage of renewables relative to total energy • Number of renewables connected on time

3.1.1.4 Hybrid

The underlying approach to revenue requirement calculations under this model is similar to that in the Outcomes-based PBR model. However, the presence of an Integrated Grid Operator ("IGO") and a Distributed System Platform Provider ("DSPP") model for the utility changes some of the underlying costs.

IGO

The IGO's funding requirements are typically collected as fees from load-serving entities and generators. Ultimately, these costs are passed on to ratepayers in the form of increments to power supply expenses. For simplification, the Project Team added IGO's costs to revenue requirements separately instead of allocating it to the utilities and PPA expenses. With an IGO, the total operating costs for the utilities in two categories are reduced.

- **Power supply expenses**: with an IGO that oversees resource planning, procurement, and system operations, there is expected benefits from increased competition. Projected expenses to purchase power produced by Independent Power Producers ("IPPs") are anticipated to be lower under an IGO and result in savings to the ratepayers and lower revenue requirements to the utilities.

- **System operations and dispatch**: with an IGO, the utilities are no longer expected to incur O&M expenses related to transmission and distribution ("T&D") planning, dispatch, and system operations as these functions would be transferred to the IGO.

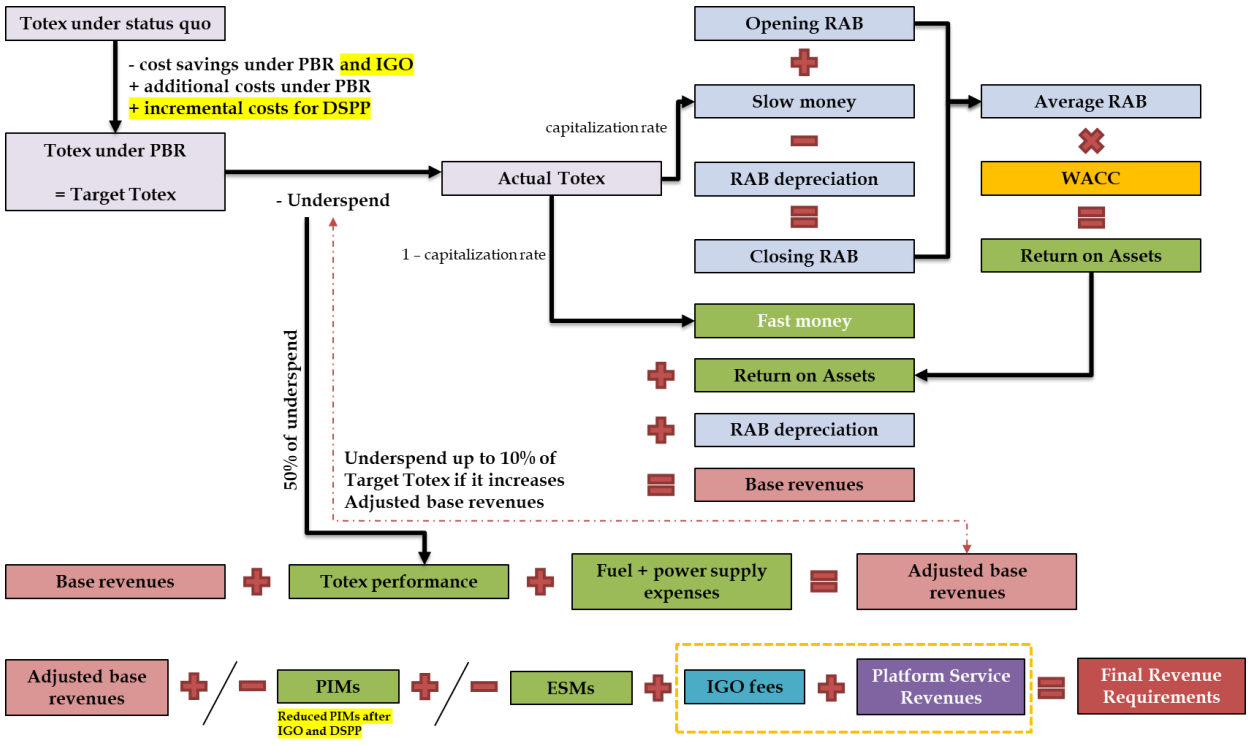
Once an IGO is operational, the Project Team assumes that the utilities no longer get rewarded or penalized for the Competitive procurement, RPS targets, and DER connection PIMs since the utilities do not fully control these functions once these responsibilities are undertaken by the IGO.

DSPP

The setup and operational costs of a distributed platform under this model are added to the target totex under the Outcomes-based PBR model. Furthermore, the utilities are expected to earn Platform Service Revenues ("PSRs") under this model. The final revenue requirements also incorporate the projected PSR revenues as an offset to the base revenues.

The approach to calculating revenue requirements under the Hybrid model is largely similar to that under the Outcomes-based PBR model; the differences between the two models are highlighted in Figure 12.

Figure 12. Revenue requirements calculations under the Hybrid model



3.1.2 Co-op

As described previously in the reports for Tasks 1.4.2 and 1.6.1/1.6.3, an electric co-op's revenue requirements are determined using a Times Interest Earned Ratio ("TIER") level. The ratio measures how many times a co-op can cover its interest expenses from its pre-tax earnings. Although the United States Department of Agriculture's ("USDA") Rural Utilities Service ("RUS") loan agreements require a minimum TIER of 1.25 for distribution utilities, the PUC sets

the TIER level for KIUC at 2.00.[8] Revenue requirements for a co-op are calculated using the following formula:

$$Revenue\ Requirement = Interest\ Expense * TIER + Operating\ Expense$$

Besides the TIER-based calculation, costs for co-ops also differ from IOUs on the following items:

- **Cost of equity**: co-ops raise equity from their members in the form of patronage capital. Therefore, the cost of equity for co-ops is effectively zero.

- **Cost of debt**: co-ops receive loans from RUS and other entities such as the Cooperative Finance Corporation ("CFC") at below-market rates.

- **Taxes**: co-ops have a tax-exempt status federally and are only required to pay state income taxes on their revenues.

This underlying calculation mechanism will apply to all the regulatory models considered for Kauai County, with slight adjustments for each model.

i) **Lighter PUC Regulation –** a "softer touch" regulatory approach to KIUC is assumed to lower the regulatory expenses for KIUC by 75% from its current levels by reducing their regulatory burden.

ii) **HERA –** a surcharge for HERA is added to the final revenue requirements for KIUC calculated using the status quo approach.

iii) **IGO –** KIUC's system operations and dispatch costs are removed from the calculation of their operating expenses under the status quo. An IGO fee is added to the final revenue requirements for KIUC. For simplification, the Project Team assumed that this fee is set at the level required to recover the IGO's funding requirements which would have been collected from both KIUC and other generators and ultimately passed through to ratepayers.

[8] Kauai Island Utility Cooperative. Docket No. 2009-0050. *Application of Kauai Island Utility Cooperative for Approval of Rate Changes and Increases, Revised Rate Schedules and Rules, and Other Ratemaking Matters. Volume 1.* June 2009.

3.2 Assumptions used for revenue requirement calculations

This section provides a summary of the assumptions used to estimate the key components of revenue requirements under each model for each county. They have been sourced from the utilities' public filings where possible and supplemented with data collected from other publicly available research and filings from other jurisdictions.

3.2.1.1 Status Quo – HECO/MECO/HELCO

Parameter	Assumptions
Capital structure and cost of capital	The HECO Companies are capitalized with a combination of: - short-term debt - long-term debt - hybrids - preferred stock - common stock The proportion and rate of return for each instrument were obtained from the current or most recent HECO/MECO/HELCO rate cases (Docket No. 2016-0328, Docket No. 2017-0150, Docket No. 2015-0170).
Effective income tax rate	For 2017, the effective state and federal income tax rates, including the effect of state income tax on federal tax rate, were obtained from HECO, MECO, and HELCO rate cases. From 2018 onwards, the analysis assumed gross federal income tax rate of 21% to be consistent with the current tax rate.
Taxes other than income taxes (revenue taxes)	The rates for public service tax, PUC fees, and franchise tax were obtained from the IOU rate cases. The payroll tax was estimated as a % of O&M labor expense.
Hawaii cost index (vs. the overall United States)	The Project Team created an index to scale the US-wide levelized costs of energy forecasts from NREL to Hawaii-specific forecasts, based on EIA – State Energy Data System 2016 (motor gasoline average price, all sectors). This was applied to forecasts of technology costs to ensure that they reflected the higher costs in Hawaii relative to the mainland.
Power plant life (years)	The useful service lives of power plant assets by technology (solar, wind, hydro) were assumed based on industry standards used by EIA.
Plant depreciation rates	The Project Team obtained depreciation rates from rate cases for the following asset categories: - Production - T&D - General - Vehicles
Regular plant retirements	The Project Team estimated plant retirements as a % of beginning-of-year plant balances from rate cases, based on an average of 2011-2015 data.

Inflation rate	2%
Annual plant O&M cost escalation above and beyond the generic 2% inflation	Estimated at 0.25% based on industry standards.
Annual capacity factor decrease	Estimated at 1% for renewables and 5% for thermal, to align generation by fuel type with HECO's projections in the PSIP.
Thermal plant efficiency loss	Estimated at 2% every five years, to align generation by fuel type with HECO's projections in the PSIP.

3.2.1.2 Outcomes-based PBR

Parameter	Assumptions
Regulatory period	5 years
Start year	2020 based on the Hawaii Ratepayer Protection Act
PBR transition costs	Annual amount was estimated in Task 2.3.1 using Alberta Utility Commission costs and applied for 2018 and 2019, assuming a two-year transition period.
Utility capital cost and structure	Same as status quo and assumed to remain constant throughout the forecast horizon. The fixed capital costs and structure approach was used for simplification and was based on the assumption that the design and implementation of PBR, especially in terms of feasibility of metrics and size of rewards and penalties, are conducted with regard to minimizing the impact on financial markets.
Capitalization rate (for totex)	Historical average ratio of Capex/(Capex+Opex) between 2017 and 2019 (3 years preceding the PBR regime). Opex excludes fuel costs and PPA expenses.
Consultants' fees for PBR	Consultants' fees for PBR proceedings of 3 Alberta utilities in 2013 CAD, converted and inflated to 2017 USD; based on LEI's experience
PIMs administration costs for utility	Average of three categories of administrative costs for HECO from its rate case filings (used as an indication of utilities' program administration costs): - administer business plans - manage safety program and training - DC Fast Charger operations
Costs to develop capital and asset management plan	HECO's costs to develop business plans, according to details on its O&M cost categories from its rate case filing.
PIMs rewards/penalties	Rewards and penalty levels based on current PIMs in Hawaii for reliability, service quality, demand response implementation, and cost savings in renewable procurement. See Section 3.2.1.6
Cost savings for utility	3% reductions for the following cost categories (based on efficiency gains from competition used for Single Buyer):

	- cost of final delivered energy to customers - total cost per customer - total cost of wires
Target totex	Totex under status quo, adjusted for changes in costs under PBR.
Additional totex savings	Utilities may also make additional totex savings if it improves their revenue requirements. Project Team assumes that underspends are due to efficiencies and therefore, the utilities could keep half of the underspend below the target totex. It is assumed that the utility would not underspend by more than 10% of the target totex to provide essential functions.
ESM	Deadband is +/- 100 basis points. Sharing of excess or insufficient earnings with customers is 50%. Note: the deadband and earnings sharing levels are the Project Team's assumptions based on a review of other jurisdictions with PBR. Excess/insufficient earnings from one regulatory period are included in the next regulatory period, spread evenly across the number of years.

3.2.1.3 Conventional PBR + Light HERA

Parameter	Assumptions
Light HERA costs	HERA funding requirements were estimated in Task 2.2.1. Startup costs and annual funding requirement (on a $/kWh basis) obtained from other reliability entities and scaled to Hawaii. Light HERA funding requirement assumed to be half of that of a full HERA.
Start year	2020
Conventional PBR	
Regulatory period	3 years
Start year	2020 based on the Hawaii Ratepayer Protection Act
PBR transition costs	Same as for Outcomes-based PBR
I	Five-year (2013-2017) average growth rate of implicit price deflator for GDP for Hawaii from DBEDT's 2017 State of Hawaii Data Book – 2.10%
X	Multifactor productivity growth between 2008 and 2014 for 86 US power distributors, from a study by US DOE's Grid Modernization Consortium – 0.22%
Utility WACC	Same as status quo
Capitalization rate (for totex)	Capex/(Capex+Opex) between 2017 and 2019 (3 years preceding the PBR regime). Opex excludes fuel costs and PPA expenses.
Consultants' fees for PBR	Consultants' fees for PBR proceedings of 3 Alberta utilities in 2013 CAD, converted and inflated to 2017 USD.
PIMs administration costs for utility	Average of three categories of administrative costs for HECO from its rate case filings (used as an indication of utilities' program administration costs): - administer business plans

	- manage safety program and training - DC Fast Charger operations
PIMs rewards/penalties	PIMs rewards/penalties are the same as Outcomes-based PBR. See Section 3.2.1.6
Cost savings for utility	3% reductions for the following cost categories (based on efficiency gains from competition used for Single Buyer): - cost of final delivered energy to customers - total cost per customer - total cost of wires
Target totex	Totex under status quo and adjusted for changes in costs PBR.
Additional totex savings	Utilities may also make additional totex savings if it improves their revenue requirements. Project Team assumes that utilities can keep 50% of the underspend below the target totex. The utility cannot (or will not) underspend by more than 10% of the target totex to provide essential functions.
ESM	Deadband is +/- 100 basis points. Sharing of excess or insufficient earnings with customers is 50%. Note: the deadband and earnings sharing levels are the Project Team's assumptions based on a review of other jurisdictions with PBR. Excess/insufficient earnings from one regulatory period are included in the next regulatory period, spread evenly.

3.2.1.4 Hybrid

Parameter	Assumptions
Outcomes-based PBR	Same as standalone Outcomes-based PBR (see above)
IGO costs	Startup and annual operating costs (on a $/MWh basis) from 2004 FERC report on RTOs and adjusted for inflation. Lower expenses from greater technical knowledge and improved technology assumed to be offset by smaller scale of Hawaii.
IGO start year	2023 For Maui County, the Project Team assumed that an IGO is only established on Maui island, due to the small size of the other two islands in the county
Utility cost reductions	Planning and dispatch operations costs for utility assumed to be 0 after IGO is functional. Power supply expenses assumed to decrease by 3% yearly from efficiency gains through increased competition.
DSPP start year	2028
DSPP costs	Costs for National Grid's DSP REV demonstration project at Buffalo Niagara Medical Campus scaled to Hawaii based on DER capacity.
Platform Service Revenues	Year 1 = 2020 PIMs under Outcomes-based PBR Revenues doubling time = 5 years

	Source – summary of staff white paper for NY REV (http://projects.exeter.ac.uk/igov/wp-content/uploads/2016/05/IGov-Introduction-to-DSO-vs-DSP.pdf)

3.2.1.5 KIUC

Parameter	Assumptions
Lighter PUC Regulation	
Lighter regulation start year	2020 based on the legal requirements needed.
Current regulatory expenses	From KIUC's 2017 Annual Report to the PUC.
Reduction in regulatory expenses	75% based on the Team's assumption of lower filing requirements.
HERA	
HERA start year	2020 based on the requirements needed to set up the HERA.
Startup costs and annual funding requirement	HERA funding requirements were estimated in Task 2.2.1. Startup costs and annual funding requirement (on a $/kWh basis) obtained from other reliability entities and scaled to Hawaii.
IGO	
IGO start year	2023 based on requirements needed to set up the IGO.
IGO costs	Startup and annual operating costs (on a $/MWh basis) from 2004 FERC report on RTOs. Lower expenses from greater technical knowledge and improved technology assumed to be offset by smaller scale of Hawaii.
Utility cost reductions	Planning and dispatch expenses for utility assumed to be 0 after IGO is functional since IGO would take over these functions.

3.2.1.6 PIMs

The Project Team has proposed a potential list of PIMs for the PBR models. As the table below indicates, the list of PIMs is more extensive for the Outcomes-based PBR model. Independent entities like IGO in the hybrid model take on some of the responsibilities of overseeing the functions relevant to the PIMs for operations and interconnection. Since the utilities do not fully control performance under those categories, they are no longer rewarded or penalized for those metrics once the IGO is active. The rewards and penalties for the PIMs are set based on the current PIMs in Hawaii for reliability, service quality, demand response implementation, and cost savings in renewable procurement. For each additional PIM proposed for the recommended models, the Project Team assigned the reward and penalty levels based on its comparability to an existing PIM.

There are three categories of reward and penalty levels:

- **Benchmarked to rate base –** for any given year, the reward or penalty level for a performance metric is set as a certain percentage of the equity's share of rate base for that year. Since the capital structure is assumed to be constant throughout the forecast horizon, the reward and penalty levels are essentially a fixed percentage of the RAB in that year. Currently, this type of rewards/penalties is used for reliability and service quality PIMs.

- **Shared savings –** for performance metrics that are tied to reducing a certain category of costs, shared savings allow the utility to earn back a fixed percentage of the actual cost reductions achieved. This mechanism incents the utility to achieve larger cost reductions since their rewards will be correspondingly greater. The existing PIM for cost savings in renewable generation procurement utilizes this approach.

- **One-time incentive payment –** the utility receives a one-time incentive payment to implement a certain program or achieve particular targets. In Hawaii, this approach is used for demand response implementation.

PIM	Reward/Penalty	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Generation availability	- no reward - 0.20% of common equity share of rate base	✓	✓	✓
Equivalent forced outage factor	- no reward - 0.20% of common equity share of rate base	✓	✓	✓

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Equivalent forced outage factor demand	- no reward - 0.20% of common equity share of rate base	✓	✓	✓
SAIFI	- no reward - 0.20% of common equity share of rate base	✓	✓	✓
SAIDI	- no reward - 0.20% of common equity share of rate base	✓	✓	✓
Number of interruptions	- no reward - 0.20% of common equity share of rate base	✓	✓	✓
Cost of final delivered energy	- 20% shared savings - no penalty	✓	✓	✓
Total cost per customer	- 20% shared savings - no penalty	✓	✓	✓
Total cost of wires	- 20% shared savings - no penalty	✓	✓	✓
Telephone calls answered on time	- reward and penalty both 0.08% of common equity share of rate base	✓	✓	✓
New customers connected on time	- reward and penalty both 0.08% of common equity share of rate base	✓	✓	✓
Number of consultations conducted	- reward and penalty both 0.08% of common equity share of rate base	✓	✓	✓
Timely conduct of competitive procurement	- no reward - 0.20% of common equity share of rate base	✓	✓	✓ (before IGO starts)
Cost savings in renewable generation procurement	- 20% shared savings - no penalty	✓	✓	✓ (before IGO starts)

Percentage of renewables relative to total energy	- no reward - 0.20% of common equity share of rate base	✓	✓	✓ (before IGO starts)
Number of renewables connected on time	- reward and penalty both 0.08% of common equity share of rate base	✓	✓	✓ (before IGO starts)
Billing accuracy	- reward and penalty both 0.08% of common equity share of rate base	✓	×	✓
First contact resolution	- reward and penalty both 0.08% of common equity share of rate base	✓	×	✓
Number of general public incidents	- no reward - 0.20% of common equity share of rate base	✓	×	✓
Transmission plan implementation progress	- reward and penalty both 0.08% of common equity share of rate base	✓	×	✓
Distribution plan implementation progress	- reward and penalty both 0.08% of common equity share of rate base	✓	×	✓
Timely processing of DER interconnection applications	- one-time incentive payment of $500,000 - no penalty	✓	×	✓ (before IGO starts)
Amount of demand response implemented	- one-time incentive payment of $500,000 - no penalty	✓	×	✓
Leverage: total debt to equity ratio	- no reward - 0.20% of common equity share of rate base	✓	×	✓
Liquidity: current ratio	- no reward - 0.20% of common equity share of rate base	✓	×	✓

3.3 Revenue requirements results

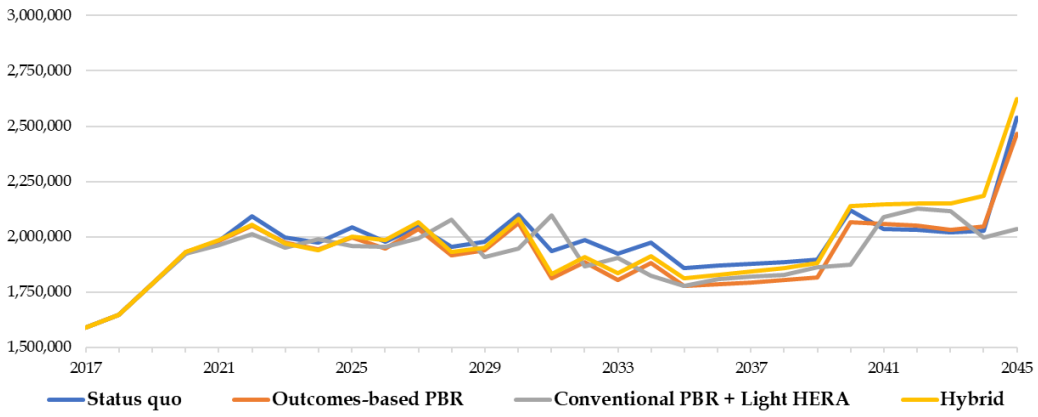
This section summarizes the projections of revenue requirements under various regulatory models in each county, including a discussion of the drivers of projected increases and decreases. The Project Team also conducted sensitivity analyses to evaluate the impact of changing underlying assumptions on overall projections.

A change in regulatory model results in savings relative to the status quo, in Net Present Value ("NPV") terms, on Honolulu, Hawaii, and Maui Counties. The status quo model results in the highest revenue requirements for Hawaii County. For Kauai County, Lighter PUC Regulation results in the lowest revenue requirements while the HERA model is the highest. The subsequent subsections will discuss these in detail.

3.3.1 HECO

The Outcomes-based PBR model has the lowest projected revenue requirements over the forecast horizon, in Net Present Value ("NPV") terms, and the status quo has the highest. The annual growth rate of revenue requirements between 2018 and 2045 under the Conventional PBR + Light HERA model is about half of that under the status quo. Relative to the status quo, all three recommended models are expected to generate savings to ratepayers: $399 million under the standalone Outcomes-based PBR model, $387 million under the Conventional PBR + Light HERA model, and $153 million under the Hybrid model. Projected revenue requirements are highest under the status quo for a majority of years in the 2020s and 2030s; from 2040, forecasted revenue requirements are highest under the Hybrid model.

Figure 13. Honolulu County revenue requirements by regulatory model ($000s, nominal)

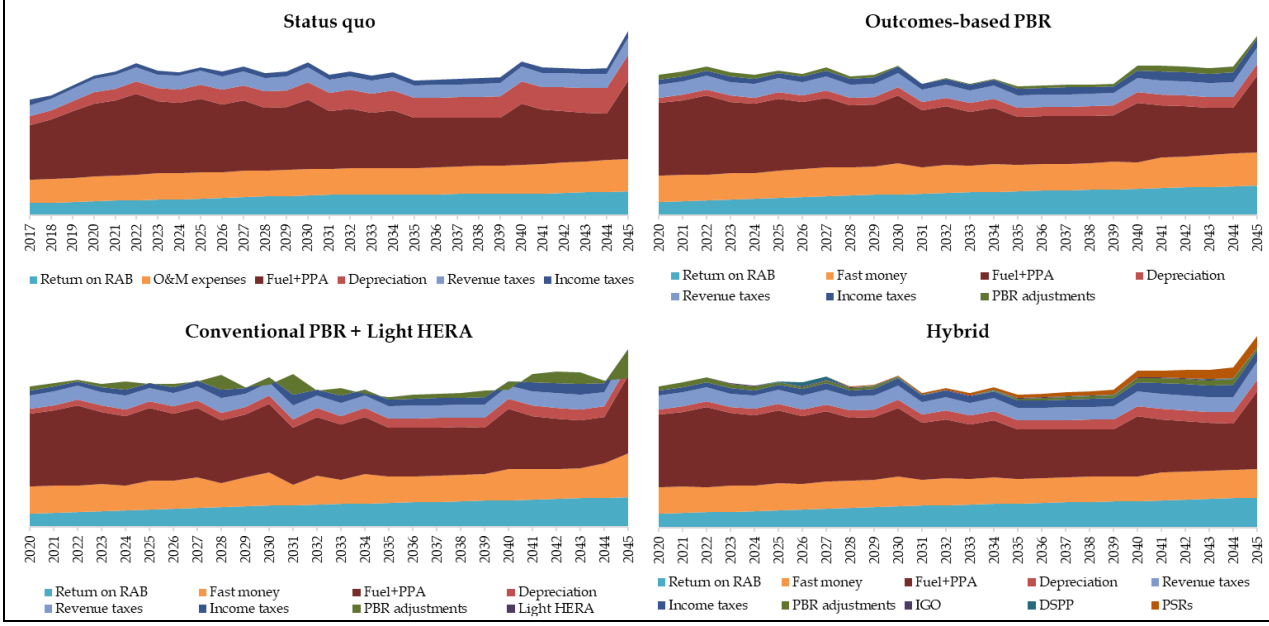


Status quo	Outcomes-based PBR	Conventional PBR+Light HERA	Hybrid
NPV (2018-2045) at 7.57% - $ millions			
$22,410	$22,011	$22,023	$22,257
Revenue requirements growth (CAGR): 2018 - 2045			
1.61%	1.50%	0.78%	1.73%

Compared to the status quo, return on RAB is projected to be higher under the other three models due to the faster growth of RAB under the totex approach. The fast money under the three PBR-based models is also expected to be lower than the O&M expense under the status quo due to anticipated efficiencies. Of the three potential models studied, fast money is expected to be

highest under the standalone Outcomes-based PBR model because it includes additional administrative costs to the utility compared to a Conventional PBR model; in the Hybrid model, these costs are offset by the transfer of the utility's system planning and dispatch functions to an IGO. PBR adjustments, which includes totex performance, PIMs, ESM, and revenue cap (for Conventional PBR), are also projected to be higher under the Outcomes-based PBR model because they are more extensive than under the other models. Rewards and penalties under some PIMs are phased out under the Hybrid model once the IGO and DSPP become operational. Conventional PBR includes fewer PIMs as well as a revenue cap which restricts the growth of revenues. For the Hybrid model, DSPP-related investment and operating costs are not expected to be significant compared to overall revenue requirements, but platform service revenues are forecast to be an important component of revenue requirements from 2035 onwards.

Figure 14. Composition of revenue requirements forecast – Honolulu County



The Project Team conducted sensitivity analyses with respect to a change in the WACC or totex capitalization rate, as shown in Figure 15 and Figure 16. A change in WACC has a much lower impact in the medium and long runs on revenue requirements under the PBR-based models, especially both models with Outcomes-based PBR. A 1 percentage-point increase in WACC would increase the projected annual revenue requirements by, on average, $51 million under the status quo model, $9 million under the Outcomes-based PBR model, $29 million under the Conventional-PBR + Light HERA model, and $9 million under the Hybrid model.

The totex approach is heavily dependent on the capitalization rate used to categorize expenses as slow money and fast money. The projected impact of a change in the totex capitalization rate is similar for both Outcomes-based PBR and Hybrid models. A 3 percentage-point increase in totex capitalization rate would increase the projected annual revenue requirements by, on average, $29 million under the Outcomes-based PBR model, $20 million under the Conventional-PBR + Light HERA model, and $29 million under the Hybrid model.

Figure 15. Sensitivities to change in WACC – Honolulu County revenue requirements forecast ($000s, nominal)

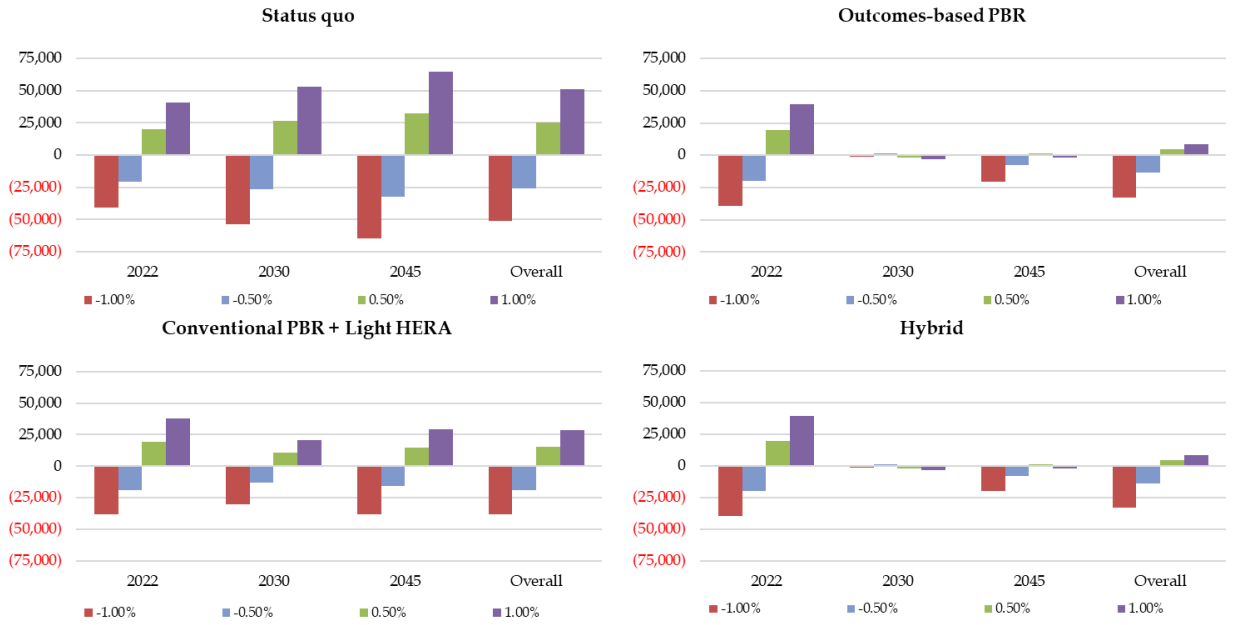
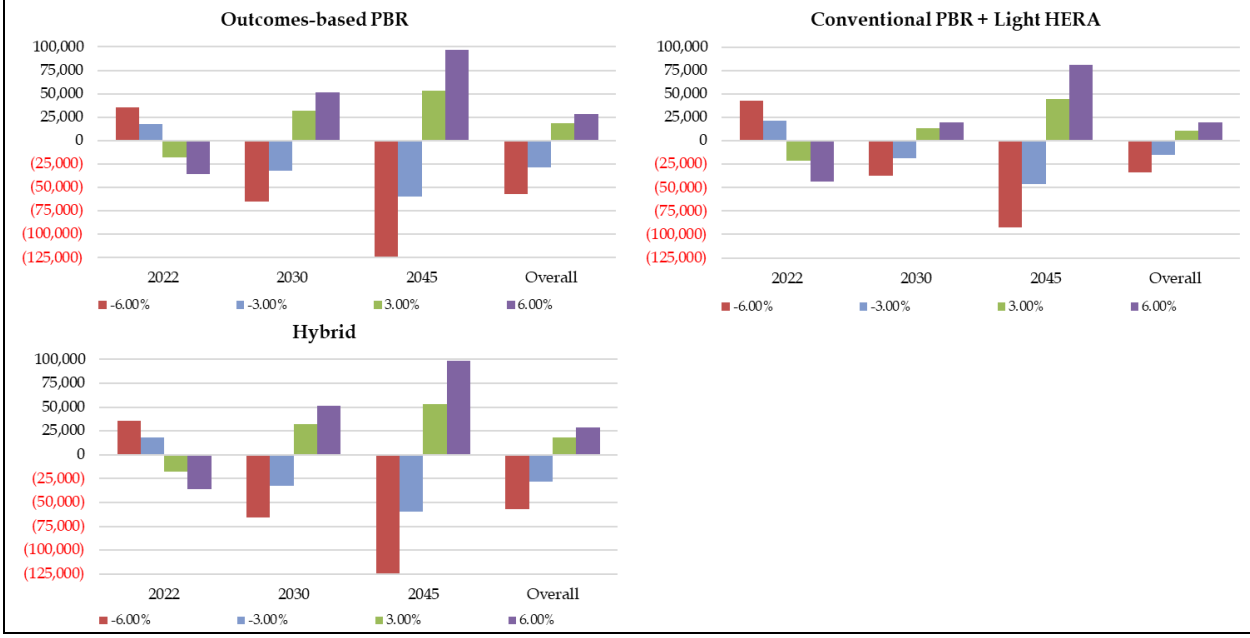


Figure 16. Sensitivities to change in totex capitalization rate – Honolulu County revenue requirements forecast ($000s, nominal)

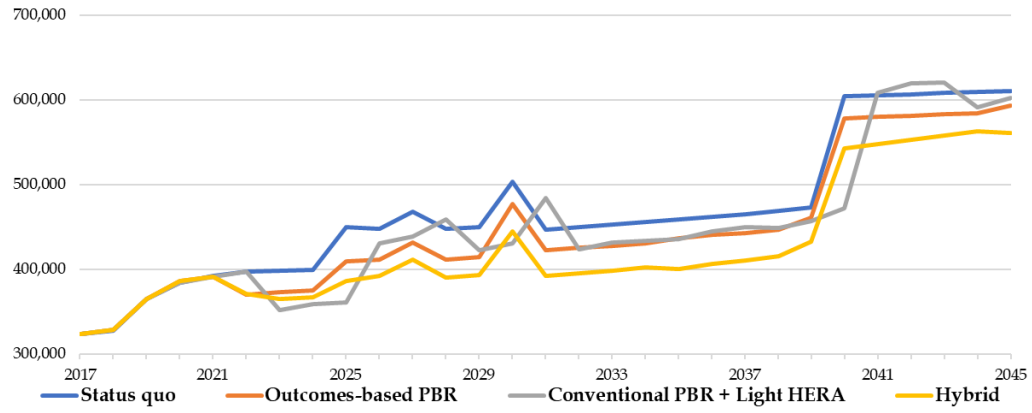


The direction of the impact is inverted over time. Increasing the totex capitalization rate decreases revenue requirements initially but eventually results in higher revenue requirements in the longer term. This change occurs because a higher totex capitalization rate implies lower fast money for the present but a larger asset base on which to earn a return over the long term.

3.3.2 HELCO

Revenue requirements under the three PBR-based models are expected to be substantially lower that the status quo. Over the entire forecast horizon, the Hybrid model has the lowest projected revenue requirements, in Net Present Value ("NPV") terms, and the status quo model has the highest. Relative to the status quo, The standalone Outcomes-based PBR saves $341 million, the Conventional PBR + Light HERA model saves $329 million, and the Hybrid model saves $506 million in NPV terms over the forecast horizon.

Figure 17. Hawaii County revenue requirements forecast by regulatory model ($000s, nominal)



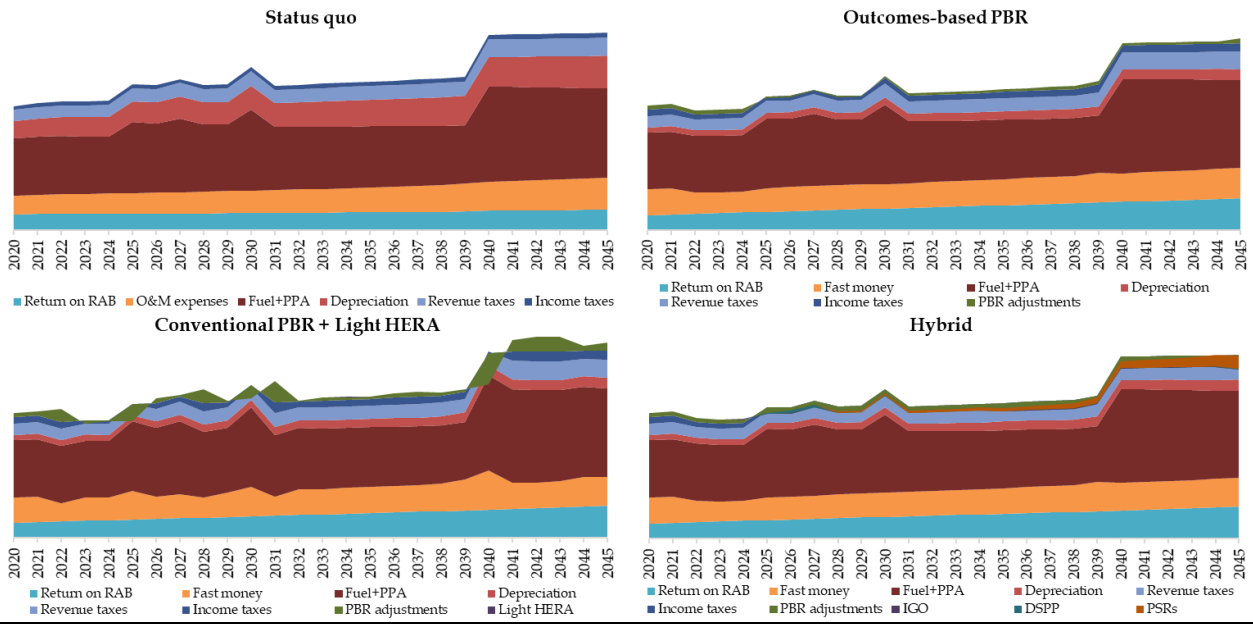
Status quo	Outcomes-based PBR	Conventional PBR+Light HERA	Hybrid
NPV (2018-2045) at 7.79% - $ millions			
$4,870	$4,650	$4,659	$4,477
Revenue requirements growth (CAGR): 2018 - 2045			
2.33%	2.22%	2.27%	2.00%

As on Honolulu County, the projected return on RAB is lower whereas the O&M expenses, relative to the fast money component under the PBR models, are higher under the status quo because RAB is expected to grow faster due to the totex approach and efficiency improvements through PBR lower some operating expenses. Projected reductions in fuel and PPA costs under the recommended models average $4 million a year from 2020 onwards or an NPV of $39 million.

All three recommended models are also expected to substantially reduce totex over the forecast horizon. The estimated reductions in totex relative to the status quo, in NPV terms, was $263 million under the Outcomes-based PBR model, $267 million under the Conventional PBR + Light HERA, and $309 million under the Hybrid model.

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Figure 18. Composition of revenue requirements – Hawaii County



The sensitivity analyses in Figure 19 and Figure 20 show that the impact of a change in WACC is different for the four regulatory models, especially in the long run. For the status quo and Conventional PBR + Light HERA models, the change in revenue requirements is proportionate to the change in WACC. For Outcomes-based PBR and Hybrid models, this is true for the short-term; in the medium- and long-term, forecasted revenue requirements in 2030 and 2045 were lower even with an increase in WACC. Over time, the impact of the ESM offset the incremental revenue requirements from a higher WACC.

With a one percentage-point increase in WACC, the annual revenue requirements are expected to increase by, on average, $10 million under the status quo model, $2 million under the Outcomes-based PBR model, $6 million under the Conventional-PBR + Light HERA model, and $2 million under the Hybrid model.

Increasing the totex capitalization rate decreases revenue requirements initially but eventually results in higher revenue requirements in the longer term because a higher capitalization rate results in lower fast money and a higher RAB; over time, the returns on a larger RAB more than offset the decrease in slow money. A 3 percentage-point increase in capitalization rate would increase the projected average annual revenue requirements by $6 million under the Outcomes-based PBR model, $3 million under the Conventional-PBR + Light HERA model, and $6 million under the Hybrid model.

Figure 19. Sensitivities to change in WACC – Honolulu County revenue requirements forecast ($000s, nominal)

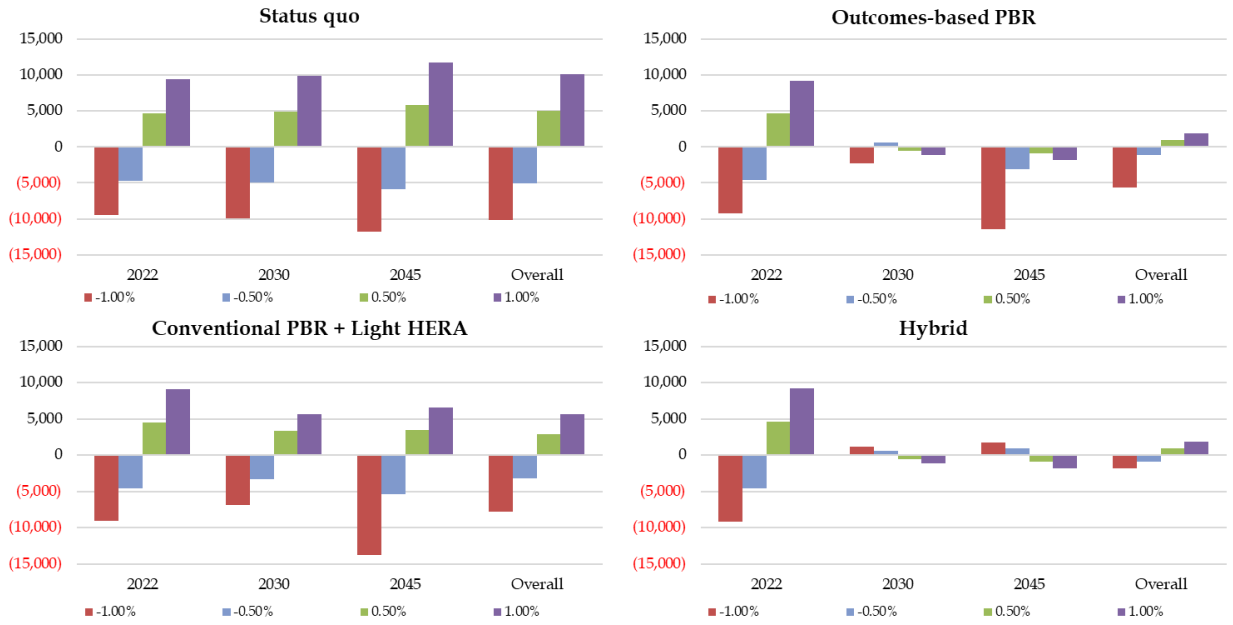
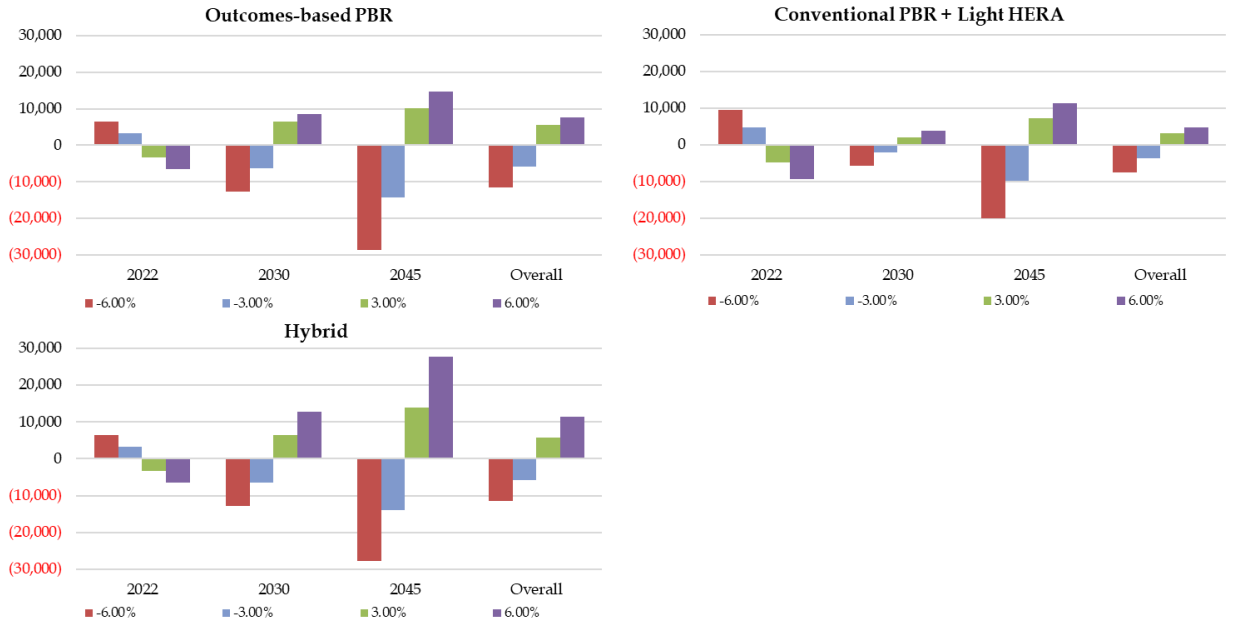


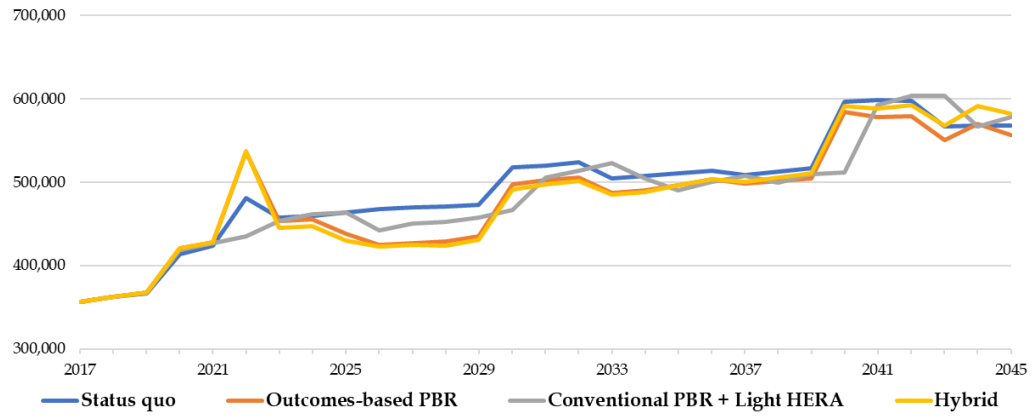
Figure 20. Sensitivities to change in totex capitalization rate – Hawaii County revenue requirements forecast ($000s, nominal)



3.3.3 MECO

Compared to the status quo, all three recommended models have lower forecasted revenue requirements. Overall, the Hybrid model has the lowest projected revenue requirements over the forecast horizon, in NPV terms, driven by lower fuel and PPA expenses. Relative to the status quo, the standalone Outcomes-based PBR saves $108 million, the Conventional PBR + Light HERA model saves $112 million, and the Hybrid model saves $119 million in revenue requirements over the forecast horizon (in NPV terms).

Figure 21. Maui County revenue requirements forecast by regulatory model ($000s, nominal)

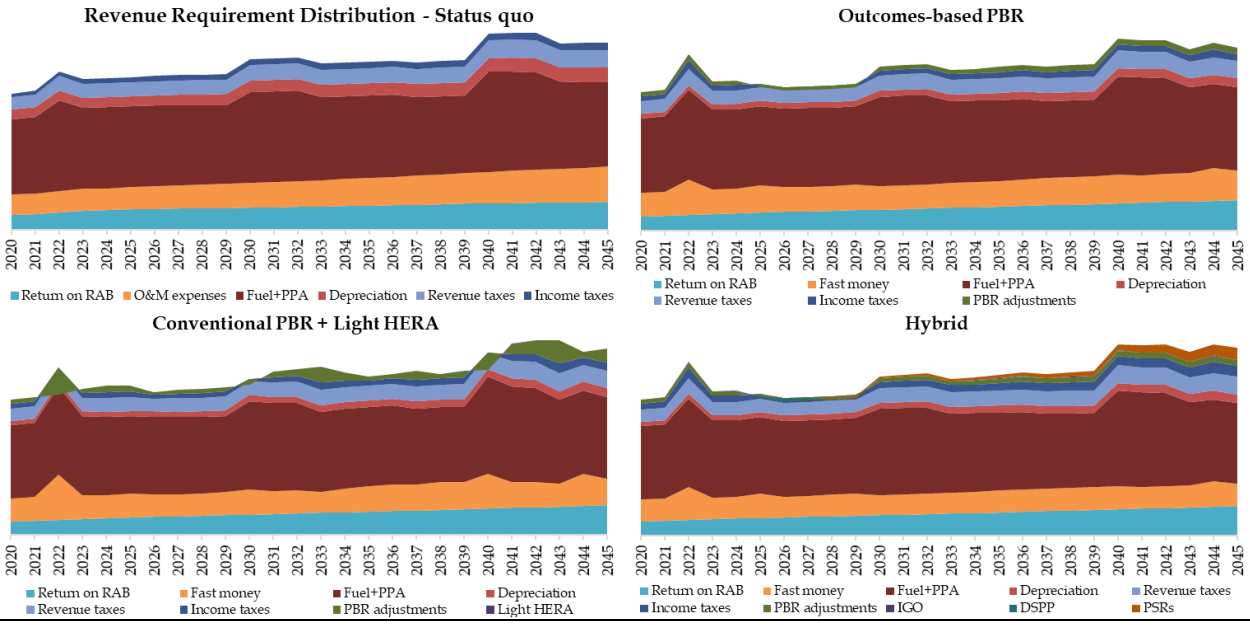


Status quo	Outcomes-based PBR	Conventional PBR+Light HERA	Hybrid
NPV (2018-2045) at 7.43% - $ millions			
$5,438	$5,330	$5,326	$5,319
Revenue requirements growth (CAGR): 2018 - 2045			
1.68%	1.59%	1.74%	1.77%

The composition of revenue requirements as shown in the graphs in Figure 22 is similar to those for Honolulu and Hawaii Counties. Return on the RAB is projected to be a growing component under the PBR models. The fast money component under the three PBR models is initially higher than O&M expenses under the status quo; over the forecast horizon, fast money is lowest under the hybrid model. Projected reductions in fuel and PPA costs under the recommended models average $4 million a year from 2020 onwards or an NPV of $37 million. Compared to the status quo, the recommended models are expected to lower totex by $271 million under the Outcomes-based PBR model, $276 million under the Conventional PBR + Light HERA, and $311 million under the Hybrid model.

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Figure 22. Composition of revenue requirements forecast – Maui County



The sensitivity analyses in Figure 23 show that a change in WACC has a more significant impact on the status quo model than the three PBR models because the ESM component of PBR offsets the additional revenue from a higher WACC. A 1 percentage-point increase in WACC is expected to increase the average annual revenue requirements by $13 million under the status quo model, compared to $8 million under the Outcomes-based PBR model, $9 million under the Conventional-PBR + Light HERA model, and $8 million under the Hybrid model. A 3 percentage-point increase in capitalization rate would increase the projected average annual revenue requirements by $2 million under all three recommended regulatory models.

Figure 23. Sensitivities to change in WACC – Maui County revenue requirements forecast ($000s, nominal)

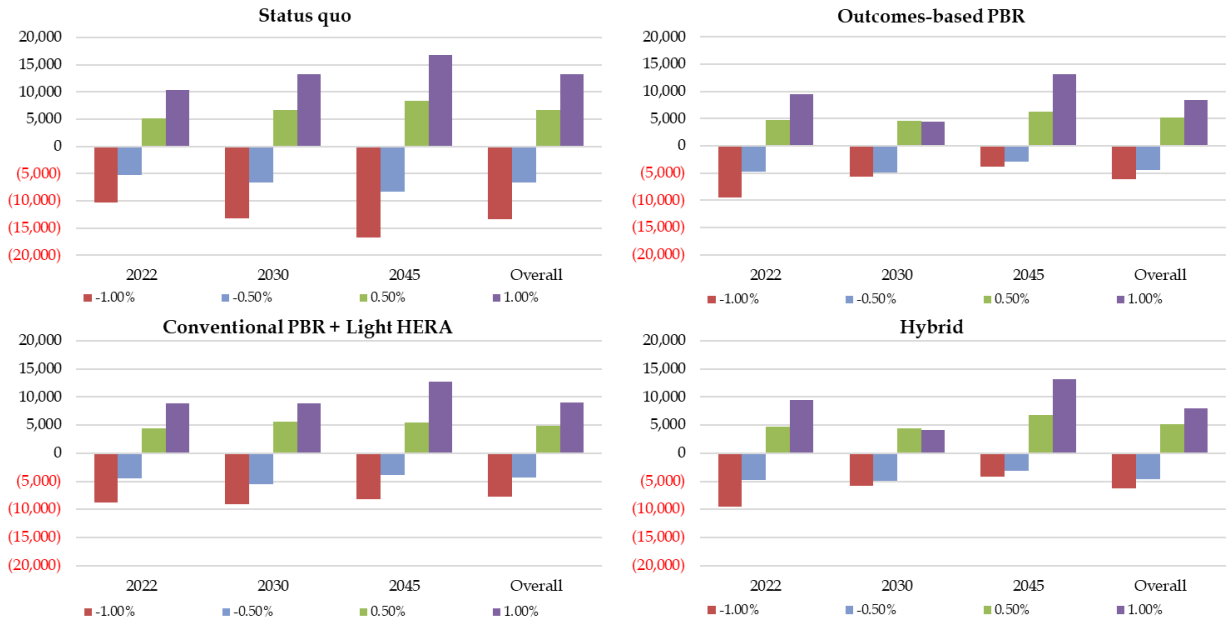
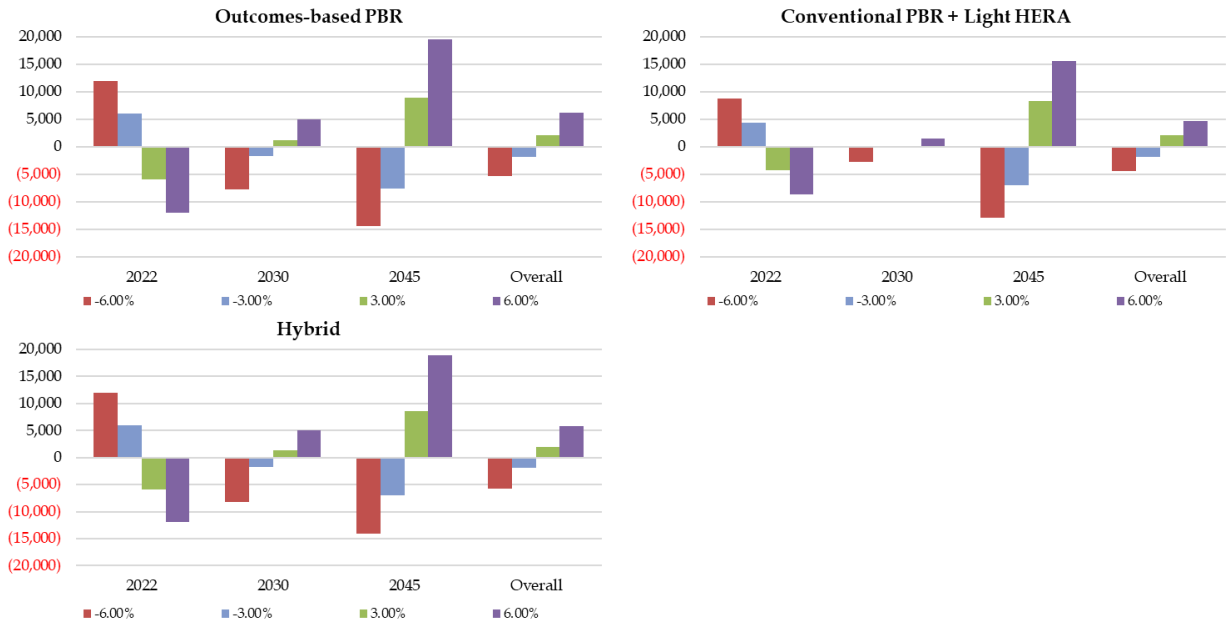


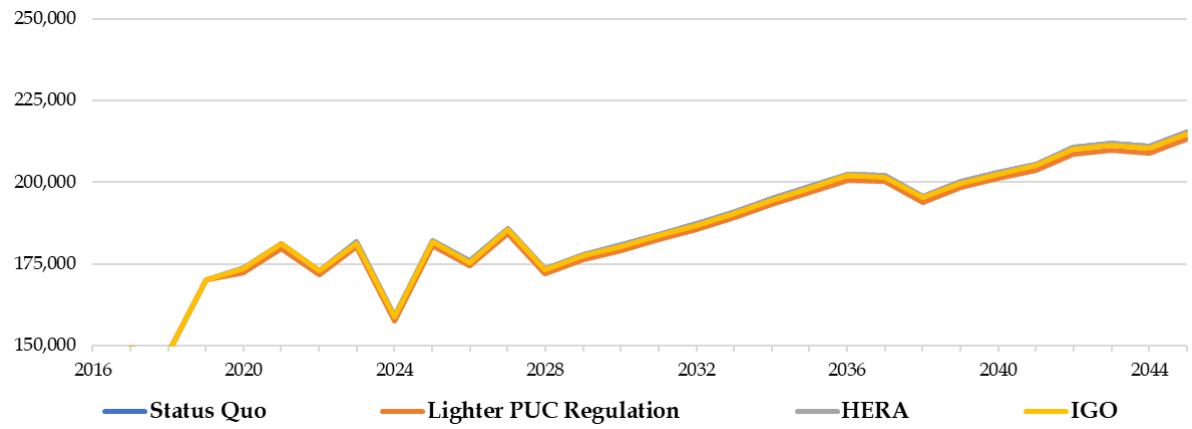
Figure 24. Sensitivities to change in totex capitalization rate – Maui County revenue requirements forecast ($000s, nominal)



3.3.4 KIUC

The revenue requirements in Kauai County are projected to be very similar under all regulatory models. Ratepayer savings under the Lighter PUC Regulation model relative to the status quo is expected to grow gradually from 0.7% in 2021 to 1% in 2045. The HERA and IGO models have an insignificant impact on revenue requirements: after the initial expenditure, projected revenue requirements are 0.01% higher under the HERA model and 0.05% lower under the IGO model. Over the forecast horizon and at 5% discount rate, the Lighter PUC Regulation model is expected to generate $21 million in savings relative to the current model; the additional costs of the HERA model and the savings from an IGO model are both forecast to be under $0.7 million.

Figure 25. Kauai County revenue requirements forecast by regulatory model ($000s, nominal)

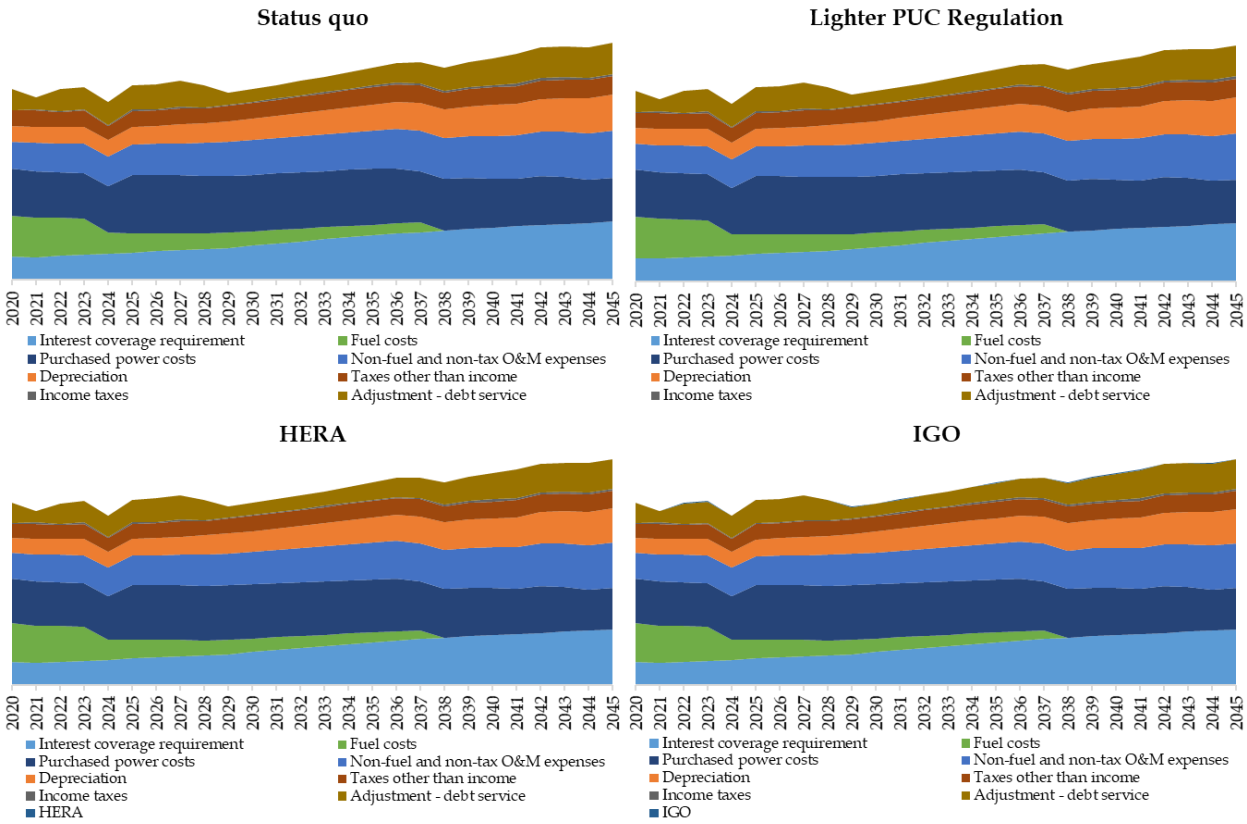


Status quo	Lighter PUC Regulation	HERA	IGO
NPV (2018-2045) at 5% - $ millions			
$2,722	$2,701	$2,722	$2,717
Revenue requirements growth (CAGR): 2018 - 2045			
1.40%	1.36%	1.40%	1.39%

The composition of revenue requirements is virtually identical under all four regulatory models considered for Kauai County; the impact of lower regulatory expenses, HERA, and IGO is barely discernible. Regulatory expenses were only about 1% of total revenue requirements in the status quo model in 2017 and therefore have a small impact. Overall, the projected near-term increase in revenue requirements is driven largely by anticipated increases in purchased power costs as new capacity comes online, as shown in Figure 26.

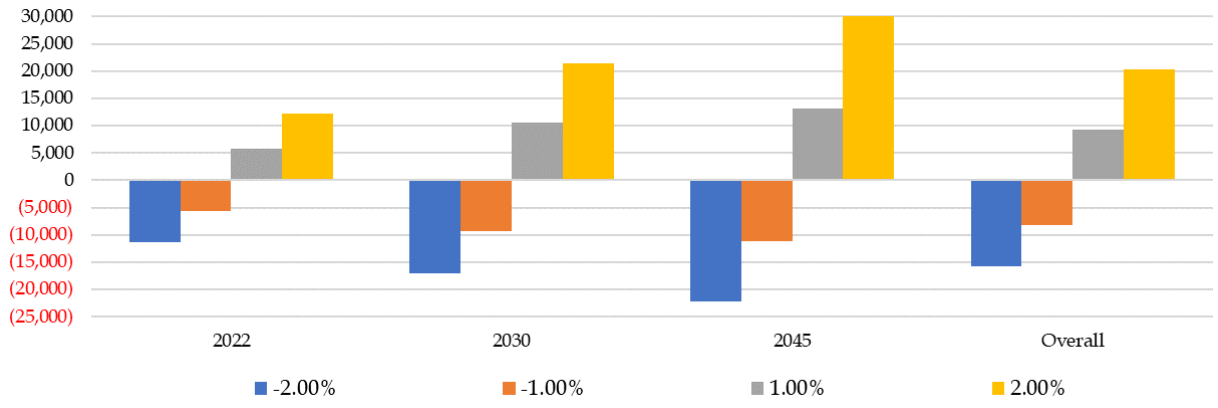
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Figure 26. Composition of revenue requirements forecast – Kauai County



The Project Team's sensitivity analyses conducted for Kauai County assessed the impact of a change in interest rate on long-term debt on the co-op revenue requirements. The results were identical across all four regulatory models. A 1 percentage-point decrease in the interest rate on the long-term debt will lower projected revenue requirements by $8 million per year, on average.

Figure 27. Sensitivities to change in WACC – Kauai County revenue requirements forecast ($000s, nominal)



4 Appendix A: Scope of work to which this deliverable responds

2.5.1 Estimated annual revenue requirement for each of the remaining regulatory models, including major costs by category; graphics comparing the three regulatory model outcomes. CONTRACTOR shall provide the expected annual revenue requirement for operation under each regulatory model through 2045, including the identification of all major cost elements.

DELIVERABLE FOR TASK 2.5.1. CONTRACTOR shall provide its conclusions and all work related to developing an estimated annual revenue requirement for each of the recommended regulatory models. CONTRACTOR shall develop an estimate of the major costs by category (essentially regulated asset base, operations and maintenance costs, cost of capital, depreciation, and tax). CONTRACTOR shall include a written summary of the findings in MS Word, an MS Excel file, which shall detail the estimated revenue requirements through 2045 under each of the regulatory models and graphics that compare the three regulatory model outcomes. CONTRACTOR shall submit deliverable for TASK 2.5.1 to the STATE for approval.

2.5.3 Analysis of how costs differ under each regulatory model as well as an explanation of the revenue requirement calculation under each model. CONTRACTOR shall provide an overview of how costs differ and how the revenue requirement is calculated under each regulatory model.

DELIVERABLE FOR TASK 2.5.3. CONTRACTOR shall provide its conclusions and all work related to an analysis of how costs differ under each regulatory model as well as an explanation of the revenue requirement calculation under each model. CONTRACTOR shall present the analysis conducted in Task 2.5.2. as well as discussion of the major differences in the drivers affecting costs and revenue, and the build-up to the revenue requirement. CONTRACTOR shall include a written summary of the findings in MS Word and Power Point. CONTRACTOR shall submit deliverable for TASK 2.5.3 to the STATE for approval.

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Assessment of projected average retail rates under each regulatory model

prepared for the Hawaii Department of Business, Economic Development & Tourism ("DBEDT") by London Economics International LLC

December 28, 2018

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This document, Task 2.5.2, is one of several working papers issued as part of this engagement. It provides a matrix comparing the projected system average retail rates under each regulatory model through 2045 for an average residential, commercial, and industrial customer. In general, the estimated rates follow the pattern of growth in overall revenue requirement for each utility and regulatory model; however, the rates do not increase as fast as the revenue requirement considering the moderate growth in load. Put differently, the increased revenue requirement is also spread over a larger number of customers throughout the forecast period. In summary, the alternative regulatory models are expected to provide lower average electricity rates with respect to the status quo across all the customer classes in all the counties, except for Lanai.

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List of acronyms

AED	Average-Excess Demand
DBEDT	Hawaii Department of Business Economic Development and Tourism
DSPP	Distributed System Platform Provider
HECO	Hawaiian Electric Company
HELCO	Hawaii Electric Light Company
HERA	Hawaii Electric Reliability Administrator
IGO	Independent Grid Operator
LEI	London Economics International LLC
MECO	Maui Electric Company
NARUC	National Association of Regulatory Utility Commissioners
NCD	Non-Coincident Demand
PBR	Performance-Based Regulation
PR	Peak Responsibility
PUC	Public Utilities Commission
TOU	Time-of-Use

1 Executive Summary

London Economics International LLC, together with Meister Consultants Group (the "Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which corresponds to Task 2.5.2 in the project scope of work, compares the estimated system average retail rates under each regulatory model through 2045 for an average residential, commercial, and industrial customer. Furthermore, this memo illustrates the projected average consumption level for the different customer classes and demonstrates how the average system rate and the aggregate bill may change through 2045 for each regulatory model.

1.1 Rate structure for utilities in the State of Hawaii

In the State of Hawaii, as is typical of the electricity industry, electricity rates vary among different customer classes. Hawaiian Electric Company, Inc. ("HECO"), Hawaiian Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Ltd. ("MECO"), collectively known as the "HECO Companies" in this memo, as well as the Kauai Island Utility Cooperative ("KIUC") have similar ratemaking procedures, including functionalization, classification, and allocation of costs necessary to render service, which then inform how rates are calculated for each customer class from the overall revenue requirement. Customer classes include residential, commercial (or general service), large power service, and other (street lighting, electric vehicles, etc.), and each class may include sub-classes. This memo focuses on the residential, commercial, and large power customer classes.

1.2 Rate estimates for all utilities and regulatory models per customer class

In order to estimate electricity rates under the various regulatory models through to 2045, the Project Team relied on the load forecast for each county (or for each island for Maui County) in the State (Task 1.5.2) as well as the revenue requirement forecast for each county (or island) under the different regulatory models (Task 2.5.1). Furthermore, the Project Team used the historical cost allocation factors, reflected in historical average rates for each utility and customer class, in order to estimate future rates for typical residential, commercial, and large power users.

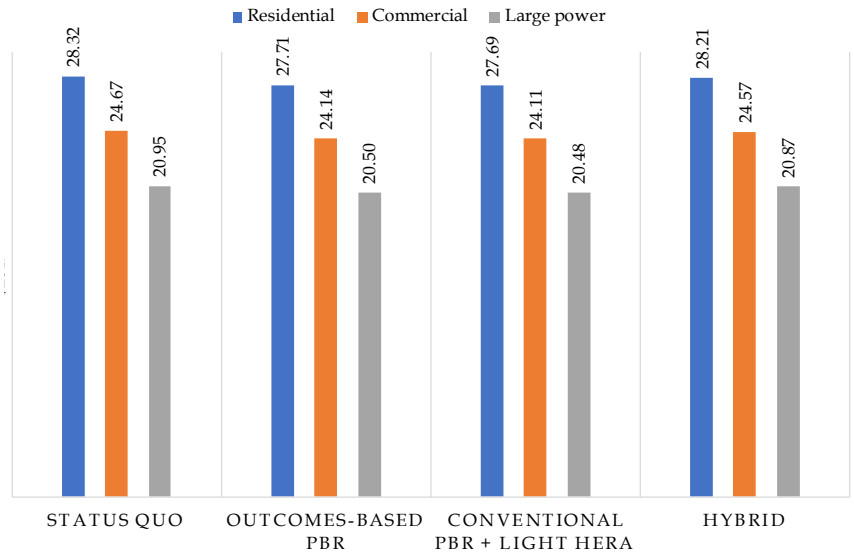
The Project Team notes that the rates mimic primarily the growth pattern of overall revenue requirements for each utility and regulatory model, but do not grow as fast as revenue requirement considering the moderate growth in load. The Project Team also notes that the differences in rates between regulatory models are predominantly driven by their differences in revenue requirements (as discussed in Task 2.5.1), as load forecasts do not vary between the models.

Furthermore, the average rates presented in this section correspond to the average over the forecast horizon of annual rates, converted from nominal dollars into constant 2017 dollars.

1.2.1 HECO projected average rates

Over the forecast horizon, average rates for HECO residential customers in Honolulu County are anticipated to range from 27.7 cents/kWh under the Outcomes-based performance-based regulation ("PBR") and Conventional PBR with Light Hawaii Electricity Reliability Administrator ("HERA") models, to 28.2 and 28.3 cents/kWh respectively for the Hybrid[1] and status quo models. In addition, the average rates across all the classes are expected to be lower under the alternative regulatory models than the status quo. Commercial and large power rates are similarly impacted, with the Outcomes-based PBR and Conventional PBR with Light HERA models showing lower than average rates relative to the other models, and the status quo resulting in the highest rates. These results are illustrated in Figure 1.

Figure 1. Projected average rates over forecast horizon in Honolulu County for each regulatory model (2017 cents/kWh)

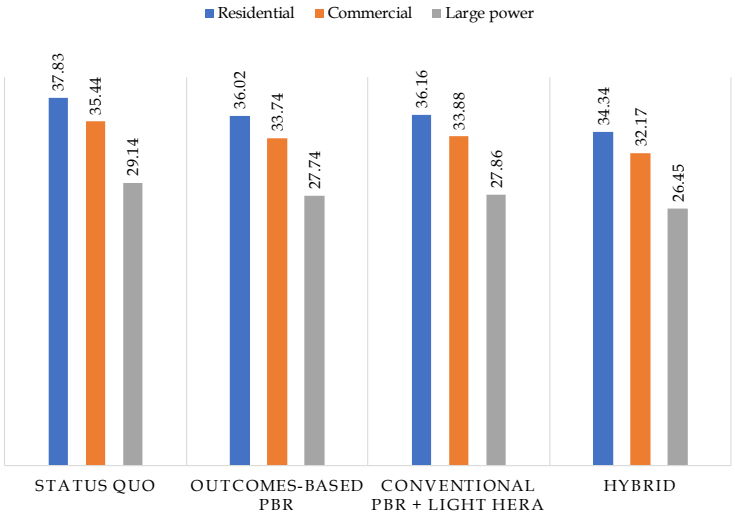


1.2.2 HELCO projected average rates

For Hawaii County residential customers, the HELCO average rates over the forecast horizon are projected to be lower under the three alternative regulatory models than the status quo. The average rates are anticipated to be approximately equivalent under the Outcomes-based PBR and Conventional PBR with Light HERA models at around 36.0 and 36.2 cents/kWh, respectively. The average rates are expected to be lowest under the Hybrid model and highest under the status quo, or approximately 34.3 cents/kWh and 37.8 cents/kWh, respectively. Commercial and large power rates are similarly impacted; these results are illustrated in Figure 2.

[1] As discussed in previous working papers, the Hybrid model comprises of the Outcomes-based PBR, distribution system platform provider ("DSPP") and Independent Grid Operator ("IGO").

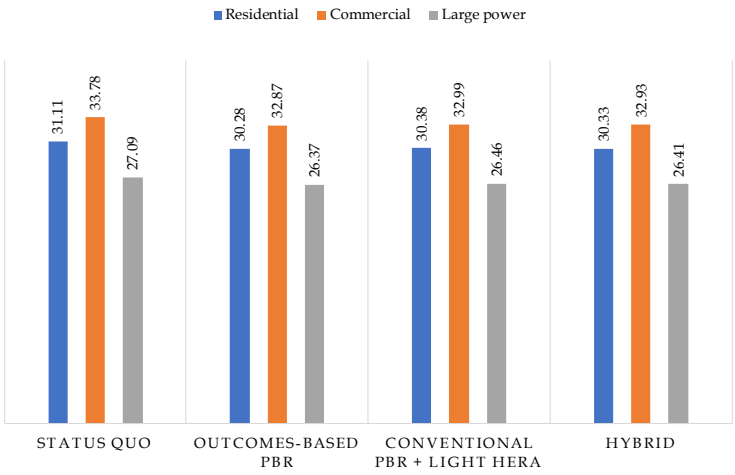
Figure 2. Projected average rates over forecast horizon in Hawaii County for each regulatory model (2017 cents/kWh)



1.2.3 MECO projected average rates

For Maui County residential customers on the island of Maui, the three alternative regulatory models are expected to provide lower average rates than the status quo. More specifically, the MECO average rates over the forecast horizon are anticipated to be similar under the Outcomes-based PBR and Hybrid models at around 30.3 cents/kWh. The average residential rates are expected to be slightly higher under the Conventional PBR with Light HERA model at approximately 30.4 cents/kWh, followed by the status quo at approximately 31.1 cents/kWh. Commercial and large power rates are similarly impacted, with results shown in Figure 3.

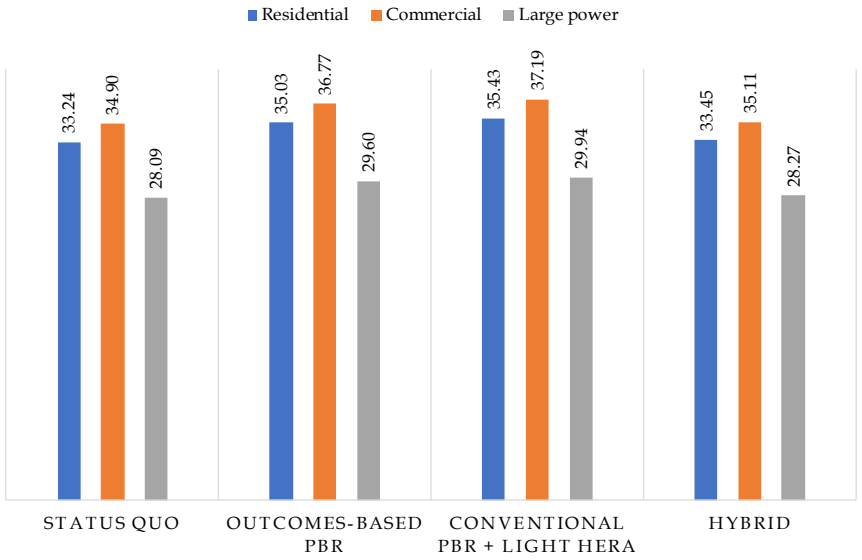
Figure 3. Projected average rates over forecast horizon on the island of Maui for each regulatory model (2017 cents/kWh)



On the island of Lanai, projected average rates over the forecast horizon are slightly higher than on the island of Maui. The three alternative regulatory models are expected to have higher

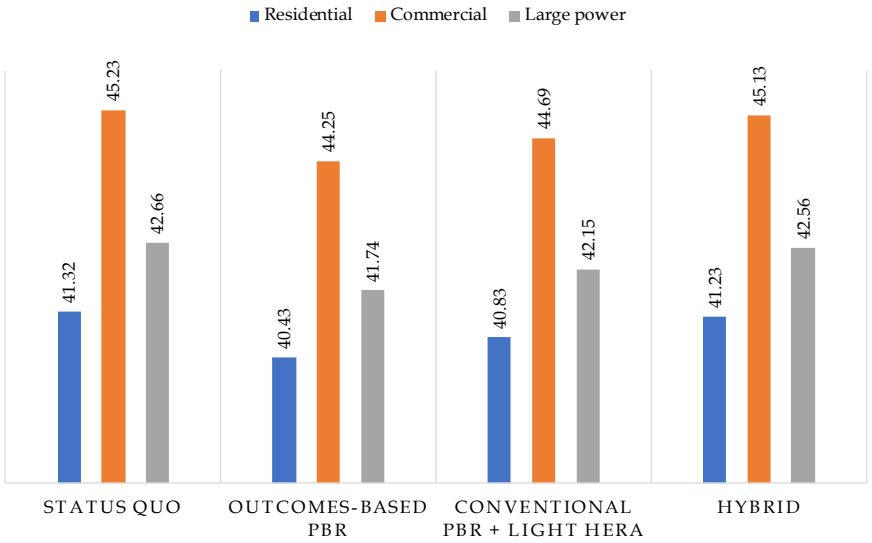
average rates than the status quo across all the classes. The highest projected average rates over the forecast horizon are found under the Conventional PBR with Light HERA model at around 35.4 cents/kWh, followed by the Outcomes-based PBR model at around 35.0 cents/kWh, the Hybrid model at about 33.4 cents/kWh, and lastly, the lowest projected average rates under the status quo at approximately 33.2 cents/kWh. Commercial and large power customers are similarly impacted. Results are depicted in Figure 4.

Figure 4. Projected average rates over forecast horizon on the island of Lanai for each regulatory model (2017 cents/kWh)



On the island of Molokai, projected average rates over the forecast horizon for MECO customers are the highest among the three Maui County islands. Historically, both Molokai and Lanai have featured higher rates than Maui. The three alternative models are expected to provide lower average rates than the status quo, with the Outcomes-based PBR resulting in the lowest average rates among the different classes of customers. Residential rates are anticipated to average approximately 41.3 cents/kWh and 41.2 cents/kWh under the status quo and Hybrid models, respectively. Projected average rates over the forecast horizon are slightly lower under the Conventional PBR with Light HERA and Outcomes-based PBR models at approximately 40.8 cents/kWh and 40.4 cents/kWh, respectively. While higher than both residential and large power rates, commercial rates are similarly impacted; commercial rates range from 44.2 cents/kWh to 45.2 cents/kWh. Large power rates, too, mimic the trends of residential and commercial rates, ranging from 41.7 cents/kWh to 42.7 cents/kWh. These rates are reflected in Figure 5.

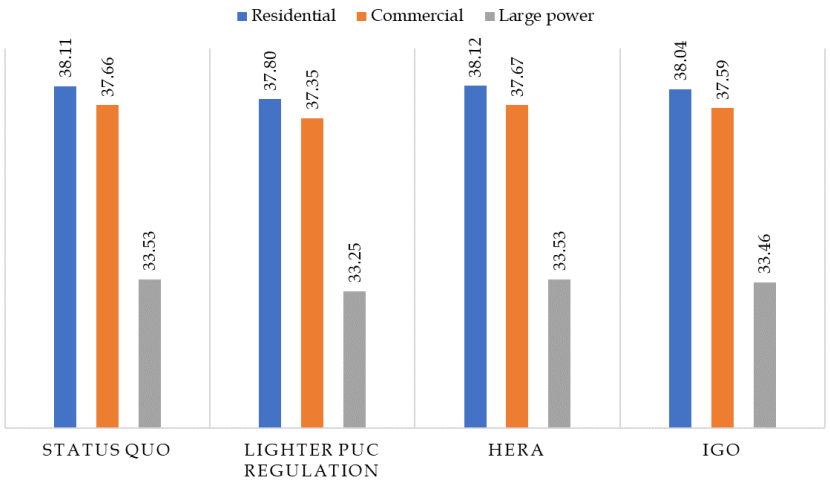
Figure 5. Projected average rates over forecast horizon on the island of Molokai for each regulatory model (2017 cents/kWh)



1.2.4 KIUC projected average rates

Lastly, for Kauai County, average rates over the forecast horizon for KIUC residential customers are anticipated to be slightly lower than the status quo at approximately 37.8 cents/kWh and 38.0 cents/kWh under the Lighter PUC regulation and IGO models, respectively. The HERA model has almost the same projected average rate as the status quo (around 38.1 cents/kWh). Commercial and large power rates are similarly impacted, with the lowest expected average rates found under the Lighter PUC regulation model, and higher rates under the other three regulatory models. These results are depicted in Figure 6.

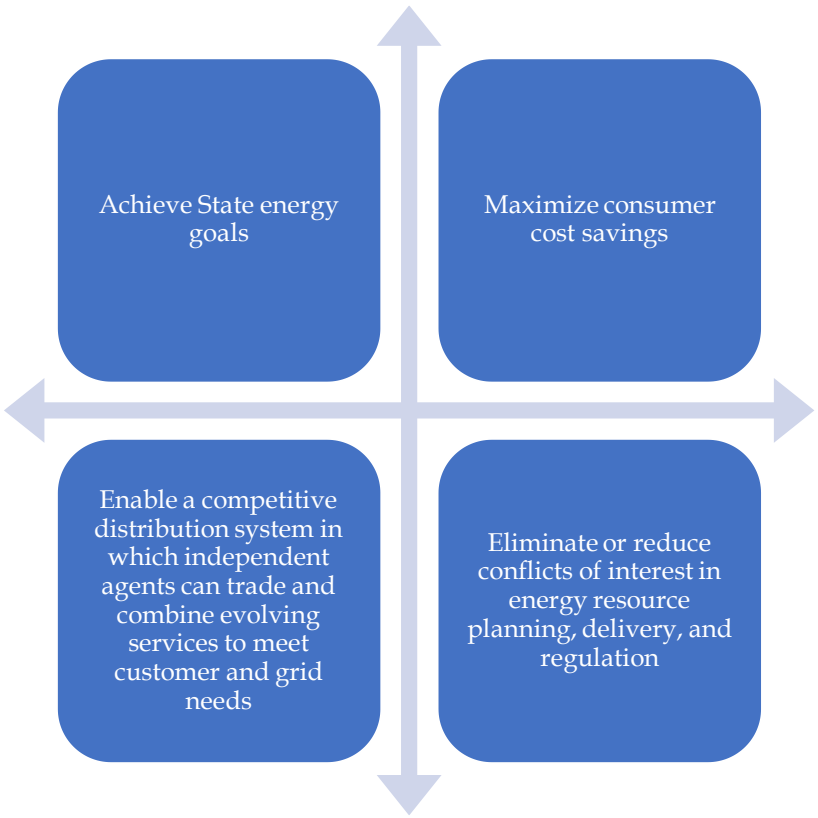
Figure 6. Projected average rates over forecast horizon in Kauai County for each regulatory model (2017 cents/kWh)



2 Introduction and scope

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the State legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. LEI, through a competitive sealed proposals procurement,[2] was contracted to perform this study.[3]

Figure 7. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

The goal of the project is to evaluate the different utility ownership and regulatory models for the State of Hawaii and the ability of each model to achieve the State's key criteria[4] listed in Figure 7. The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the State. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms

[2] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[3] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[4] House Bill No. 1700 Relating to the State Budget.

of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[5]

This deliverable corresponds to Task 2.5.2 in the project scope of work. It includes forecasted system average retail rates through 2045 using the revenue requirement from Task 2.5.1 (Estimated annual revenue requirement for each of the selected regulatory models). For the HECO Companies, the three alternative regulatory models to the status quo are comprised of the Outcomes-based PBR, Conventional PBR with Light HERA, and Hybrid (i.e., Outcomes-based PBR with DSPP and IGO) models. For KIUC, on the other hand, the three alternative regulatory models to the status quo are comprised of the Lighter Public Utilities Commission ("PUC") regulation, HERA, and IGO models. This document also includes a matrix comparing the projected system average retail rates under each regulatory model for an average residential, commercial, and industrial customer. Overall, this memo illustrates the average consumption level for the different customer classes and shows how average system rates and the aggregate bill may change through 2045 for each regulatory model.

[5] Hawaii Contract No. 65595. Scope of Services.

3 Current electricity rates in the State of Hawaii

As is common in the electricity industry, electricity rates vary by customer classes in the State of Hawaii. In this regard, both the HECO Companies and KIUC employ similar ratemaking procedures to inform how rates are calculated for each applicable rate schedule. The rate structure, the HECO Companies' and KIUC's calculation methodologies, and the role of the Hawaii PUC in ratemaking are discussed in detail in Task 1.6.4 (Comparison of projected average retail rates under each ownership model) and summarized in the sections below.

3.1 Rate structure

HELCO and MECO both have five rate classes, namely "R" Residential, "G" Small Power Use Business, "J" Medium Power Use Business, "P" Large Power Use Business, and "F" Street Lighting. HECO, in addition to the five rate classes, has an additional rate class called "DS" Large Power Directly Served Services. Descriptions of the applicability of each rate class under the HECO Companies have been provided in Task 1.6.4.

Similarly, KIUC has eight rate classes, namely Schedule "D" Residential, Schedule "G" Small Commercial, Schedule "J" Large Commercial, Schedule "L" Large Power (Primary), Schedule "P" Large Power (Secondary), Schedule "NEM PILOT", Schedule "Q" Modified – Cogenerators, and Schedule "SL" Street Lighting. Of these, Schedule "NEM PILOT" and Schedule "Q" are energy credit payment rates to customers ($ per kWh). The thresholds KIUC uses to separate commercial rate classes are different from those of the HECO Companies and are described in detail in Task 1.6.4.

The HECO Companies' and KIUC's average rates for each rate class in 2017 are shown in Figure 8 and Figure 9. Cost components (e.g., energy consumption, customer charge, Green Infrastructure Fee, demand charges, etc.) within the current rates are discussed in Task 1.6.4.

Figure 8. HECO Companies: average price of electricity (2017 average cents/kWh)

Rate Schedule	HECO	HELCO	MECO			Average
			Maui	Molokai	Lanai	
"R" Residential	28.22	34.2	30.64	35.57	35.87	32.90
"G" Small Power Use Business	29.33	39.24	34.12	42.70	40.98	37.27
"J" Medium Power Use Business	24.31	30.39	29.35	34.52	38.60	31.43
"P" Large Power Use Business	22.18	26.76	26.83	27.23	34.02	27.40
"DS" Large Power Use Business, Directly Served	20.73					20.73
"F" Street and Park Lighting	25.26	33.41	27.57	33.07	35.05	30.87

Note: These numbers are derived by dividing the total revenue by the total kWh sold for each category during the year.
Source: HECO Companies. Rates and Regulations – Average price of electricity. Website. <https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/average-price-of-electricity>. Access Date: October 12, 2018.

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Figure 9. KIUC: average price of electricity (2017 average cents/kWh)

Rate Schedule	KIUC
Residential	34.52
Commercial	34.19
Large Power	30.70
Street Lighting	80.59
Irrigation	15.98

Note: These figures are derived by dividing the total revenue by the total kWh sold for each category during the year.
Source: KIUC. "KIUC Miscellaneous Data 2013-2017." Annual Report to the PUC (December 31, 2017). PDF page 47.

3.2 The HECO Companies' and KIUC's rate calculation methodologies

The PUC is responsible for determining total annual revenues required by the HECO Companies to cover both expenses and the opportunity to earn a fair return on its investments. Each of the determined cost components of the revenue requirement are then allocated amongst customer classes as a function of cost to provide services to said customer classes.

To determine the costs borne by the different rate classes, the HECO Companies utilize a cost of service study tool. Specifically, the HECO Companies rely on an embedded cost of service study (as opposed to a marginal cost study). The embedded cost of service study methodology is comprised of three major steps: functionalization of costs into generation, transmission, and distribution functions; classification of functionalized costs into energy-related, demand-related, and customer-related costs; and the allocation of cost components to the different rate classes. KIUC also uses a similar embedded cost approach for the cost of service analysis (including functionalization, classification, and allocation). Further details on each of these steps taken by the HECO Companies and KIUC are provided in Task 1.6.4.

3.3 Role of PUC in ratemaking

All rates, schedules, rules, and practices made or changed by public utilities are subsequently filed with the PUC. According to the Hawaii Revised Statutes ("HRS") Chapter 269-16, the PUC is required to issue its decision within nine months from the date the application is filed by the utility.[6] The PUC has adopted a cost of service mechanism, a decoupling mechanism, and earnings sharing mechanism as part of the regulatory framework explained further in Task 2.1.1 (Review of potential regulatory models that could be applied in Hawaii State) and Task 3 (Additional Analyses). The rate design methodology described above has also been approved by the PUC in recent rate cases for KIUC (Docket 2009-0050), HECO (Docket 2016-0328), and HELCO (Docket 2015-0170).[7]

[6] HRS 269-16.

[7] Interim rate order approved for HELCO. Revised one step interim rate increase authorized, effective 2/16/18 for HECO.

4 Forecast of electricity rates under various regulatory models

In order to calculate the electricity rates under the various regulatory models through to 2045, the Project Team relied on the load forecast for the various counties and islands (Task 1.5.2), as well as the revenue requirement forecast for each county and island under the different regulatory models (Task 2.5.1). Furthermore, the Project Team used the historical cost allocation factors, reflected in historical average rates for each utility and customer class, to estimate future rates for typical residential, commercial, and large power users.

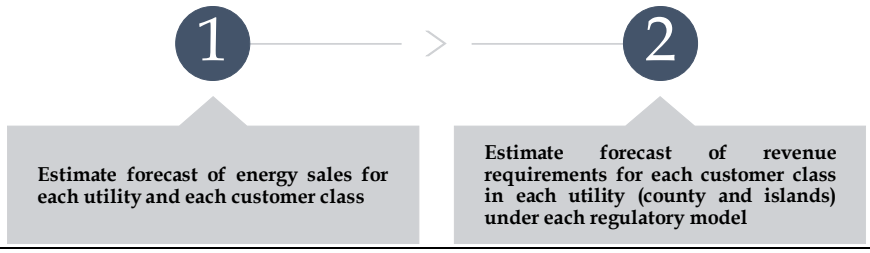
4.1 Methodology to estimate future rates

The methodology employed to determine future rates is similar to the methodology used in Task 1.6.4. The Project Team first used historical 2016[8] data from the utilities' annual reports to the PUC to calculate the ratios of electricity sales, electricity revenues, and number of customers per customer class for each of the utilities in the State of Hawaii, as illustrated in Figure 11.

- The electricity sales ratio represents the share of electricity sales (in MWh) for each customer class;
- The electricity revenues ratio represents the share of electricity revenues (in dollars) for each customer class; and
- The average number of customers ratio represents the ratio of customers for each customer class.

As a first step, the Project Team divided the load forecast for each utility into an estimate of energy sales for each class of customer. To do this, the Project Team applied the historical electricity sales ratios per customer class illustrated in Figure 11 to the load forecast for each utility that was created as part of Task 1.5.2. As a second step, the Project team divided the forecast of revenue requirements for each county and island, as well as for each regulatory model, into revenue requirements for each class of customer. For this task, the Project Team used the electricity revenues ratios illustrated in Figure 11.

Figure 10. Elements of estimated projected rates



[8] In this case the Project Team relied on 2016 data even though 2017 data is available so that the methodology is consistent with, and results comparable to, Task 1.6.4. Nonetheless, 2017 and 2016 ratios are comparable, with differences in energy sales, revenue, and customer ratios ranging from -1.0% to 1.2%.

Figure 11. Historical distribution of electricity sales, electricity revenues, and the average number of customers per customer classes for utilities in the State of Hawaii

Customer class	HECO			HELCO		
	Electricity sales ratio	Electricity revenues ratio	Avg. nb. of customers ratio	Electricity sales ratio	Electricity revenues ratio	Avg. nb. of customers ratio
Residential	23.7%	28.1%	88.9%	36.2%	39.3%	84.5%
Commercial	32.0%	33.0%	10.6%	39.3%	40.1%	15.1%
Large Power	43.7%	38.3%	0.1%	24.2%	20.3%	0.1%
Other	0.5%	0.6%	0.4%	0.3%	0.3%	0.2%

Customer class	MECO - Maui Island			MECO - Lanai Island		
	Electricity sales ratio	Electricity revenues ratio	Avg. nb. of customers ratio	Electricity sales ratio	Electricity revenues ratio	Avg. nb. of customers ratio
Residential	32.9%	33.6%	85.5%	25.2%	26.7%	85.6%
Commercial	31.8%	35.2%	14.0%	29.4%	32.7%	14.0%
Large Power	34.8%	30.9%	0.2%	45.0%	40.3%	0.2%
Other	0.5%	0.4%	0.3%	0.4%	0.3%	0.2%

Customer class	MECO - Molokai Island			KIUC		
	Electricity sales ratio	Electricity revenues ratio	Avg. nb. of customers ratio	Electricity sales ratio	Electricity revenues ratio	Avg. nb. of customers ratio
Residential	35.5%	34.1%	83.2%	37.3%	39.1%	77.2%
Commercial	43.3%	45.5%	16.2%	25.8%	26.7%	12.5%
Large Power	19.2%	19.1%	0.3%	36.3%	33.4%	0.3%
Other	2.0%	1.3%	0.3%	0.6%	0.9%	9.9%

Notes: The electricity sales, electricity revenues, and average number of customers ratios are based on 2016 values for the HECO Companies and KIUC, except for MECO revenue ratios by island due to unavailability of information. Consequently, the electricity revenues ratios for the three islands (i.e., Maui, Lanai, Molokai) were estimated based on 2018 electric revenues by island at present rates. Therefore, it is assumed that 2016 revenue ratios by rate class were approximately equivalent to the revenue ratios by rate class in 2018; Nb = Number.

Source: HECO, HELCO, MECO, and KIUC annual reports to the PUC; MECO 313, 402 Docket No. 2017-0150.

4.2 Forecast of rates

Using the annual revenue requirement per customer class calculated in step one, divided by the annual electricity sales per customer class derived in step two, the Project Team created estimates of average electricity rates per customer class for each utility and each regulatory model. The resulting rates are illustrated in Figure 26 through Figure 29 for HECO, HELCO, MECO, and KIUC.

Of note is that the trend of rates over time follows the growth pattern in overall revenue requirement for each utility and regulatory model, but do not grow as fast as the revenue requirement given the moderate increase in load. The Project Team also notes that the differences in rates among regulatory models are predominantly driven by their differences in revenue requirements (as discussed in Task 1.6.3), as load forecasts do not vary between the models.

Finally, to illustrate the impact of rate changes on the customers, the Project Team calculated average customer charges for each customer class, county, island, and regulatory model by dividing the appropriate revenue requirement by the average number of customers in each class. Of note is that rates under regulatory models employing combinations of two or more regulatory mechanisms (i.e., Conventional PBR with Light HERA and the Hybrid models) are all-inclusive, thereby bundling the costs for the utility, HERA, and IGO, where applicable.

4.2.1 HECO

The alternative regulatory models are expected to result in lower average electricity prices than the status quo across all the customer classes in Honolulu County. Projected average rates over the forecast horizon for HECO residential customers are anticipated to range from 27.7 cents/kWh under the Outcomes-based PBR and Conventional PBR with Light HERA models, to 28.2 and 28.3 cents/kWh under the Hybrid and status quo models, respectively. Commercial and large power rates are similarly impacted, with the Outcomes-based PBR and Conventional PBR with Light HERA models showing lower average rates than the other models. These results are depicted in Figure 12.

The Project Team notes that to calculate the average rates over the forecast horizon, the forecasted rates were converted from nominal dollars into constant 2017 dollars before averaging all values over the forecast horizon.

Figure 12. Projected average rates over forecast horizon in Honolulu County for each regulatory model

2017 cents/kWh	Status quo	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Residential	28.3	27.7	27.7	28.2
Commercial	24.7	24.1	24.1	24.6
Large power	21.0	20.5	20.5	20.9

Similarly, Figure 13 illustrates the average impact that the regulatory models would have on monthly customer bills[9] over the forecast horizon while considering the average consumption of each customer class. The table shows that the average monthly bills for the alternative models are projected to be lower than the status quo across all the customer classes. These figures are also shown in constant 2017 dollars.

Figure 13. Projected average monthly bill over forecast horizon in Honolulu County for each regulatory model

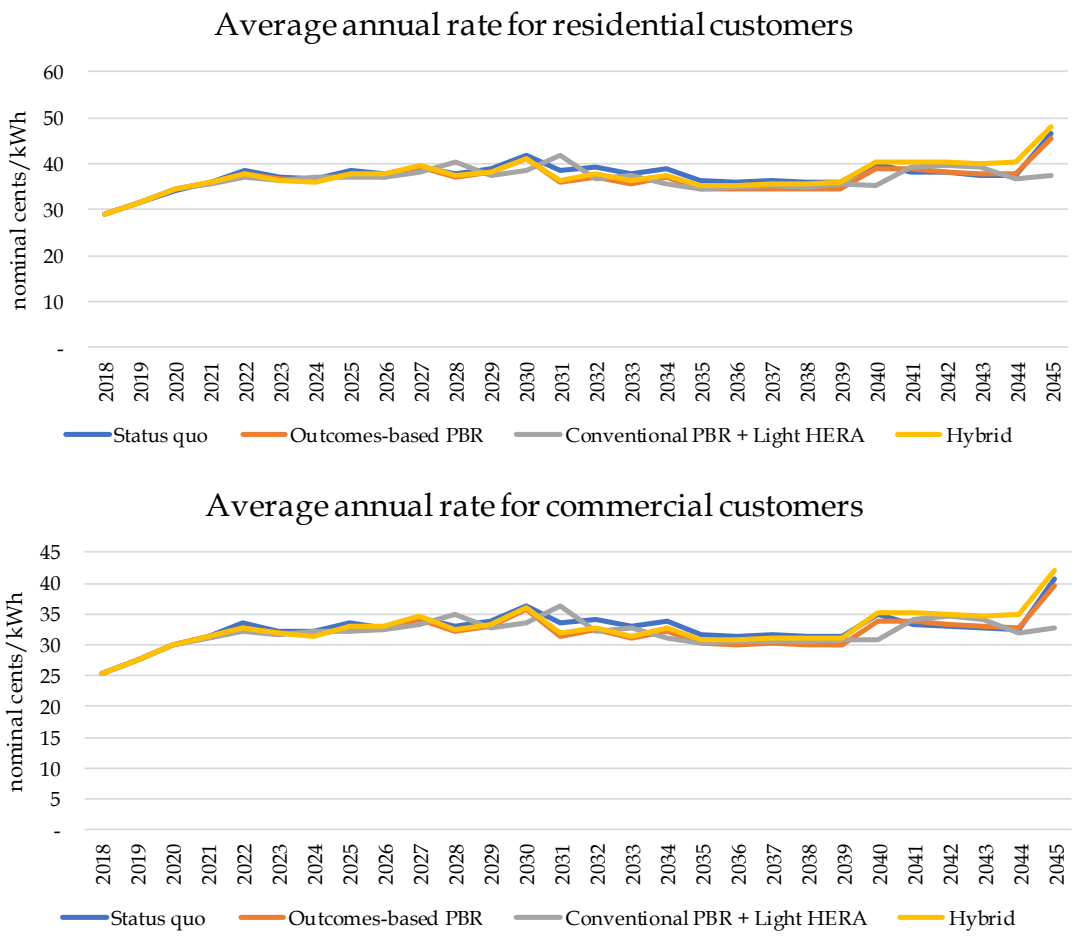
2017 dollars	Status quo	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Residential	$ 121	$ 118	$ 118	$ 120
Commercial	$ 1,188	$ 1,163	$ 1,162	$ 1,183
Large power	$ 102,588	$ 100,465	$ 100,357	$ 102,199

The trends in projected average annual rates under various regulatory models are similar across the customer classes in Honolulu County in that they show a generally increasing trend through 2045. The average year-over-year growth in forecasted average annual rates for all three customer types from 2018 to 2045 is 2.0%, 1.8%, 1.1%, and 2.1% for the status quo, Outcomes-based PBR,

[9] Customers bills are comprised of energy charges, based on kilowatt-hours used and the price of electricity, in addition to fixed monthly customer charges and other adjustments. (Source: "Understanding Your Bill." *Hawaiian Electric.* Web. October 17, 2018. < https://www.hawaiianelectric.com/billing-and-payment/understanding-your-bill>

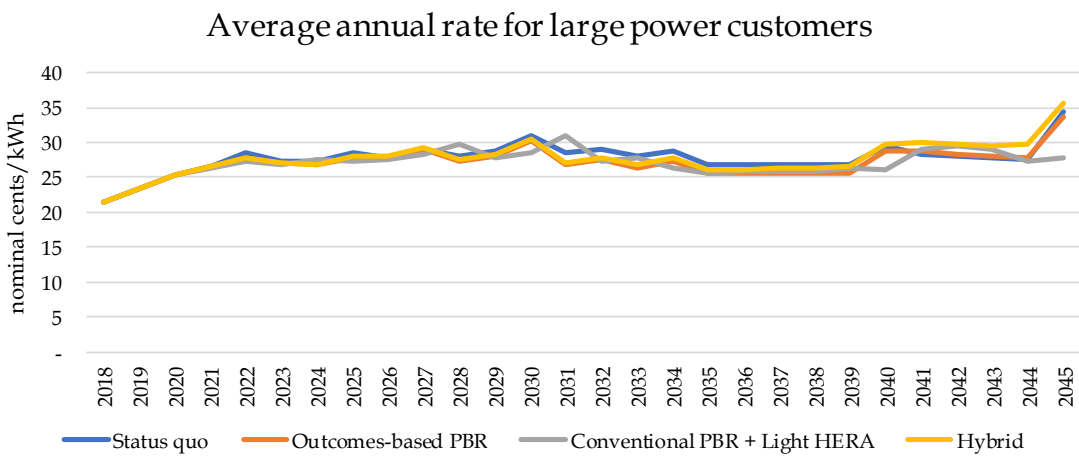
Conventional PBR with Light HERA, and Hybrid models, respectively.[10] Furthermore, the graphs below show that the status quo is projected to feature the highest annual rates for most years across the forecasted horizon for all the customer classes. On the other hand, the Conventional PBR with Light HERA model is anticipated to have the lowest annual rates in most of the years for all the customer classes. The revenue cap mechanism included in this model helps to limit sudden increases in rates following large expenditures. For instance, under most models the rates are projected to increase sharply in 2045 due to the conversion of existing oil-fired generation plants to bio-diesel, whereas the rate increase under the Conventional PBR + Light HERA model is expected to be more gradual because the "I – X" formula[11] limits revenue growth. Figure 14 illustrates the trends in rates for residential, commercial, and large power customers in Honolulu County (values are in nominal dollars).

Figure 14. Projected average annual rates forecast for HECO under various regulatory models



[10] Note that in order to calculate these average growth rates over the forecast horizon, the Project Team calculated the annual growth rates between all years through to 2045, before averaging all values over the forecast horizon.

[11] Revenue growth under the Conventional PBR model is capped using an indexing formula: inflation (I) less productivity factor (X), or commonly referred to as I – X. This is described in more detail in Task 2.1.1.



4.2.2 HELCO

Projected average rates over the forecast horizon for HELCO residential customers are anticipated to be approximately 34.3 cents/kWh under the Hybrid model, 36.0cents/kWh under the Outcomes-based PBR model, 36.2 cents/kWh under the Conventional PBR with Light HERA model, and 37.8 cents/kWh under the status quo. Commercial and large power rates are also similarly impacted, in that the Hybrid model has the lowest projected average rates and the status quo has the highest. These results are illustrated in Figure 15.

Note that to calculate these average rates over the forecast horizon, the Project Team converted the forecasted rates from nominal dollars to constant 2017 dollars before averaging the values over the forecast horizon.

Figure 15. Projected average rates over forecast horizon in Hawaii County for each regulatory model

2017 cents/kWh	Status quo	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Residential	37.8	36.0	36.2	34.3
Commercial	35.4	33.7	33.9	32.2
Large power	29.1	27.7	27.9	26.5

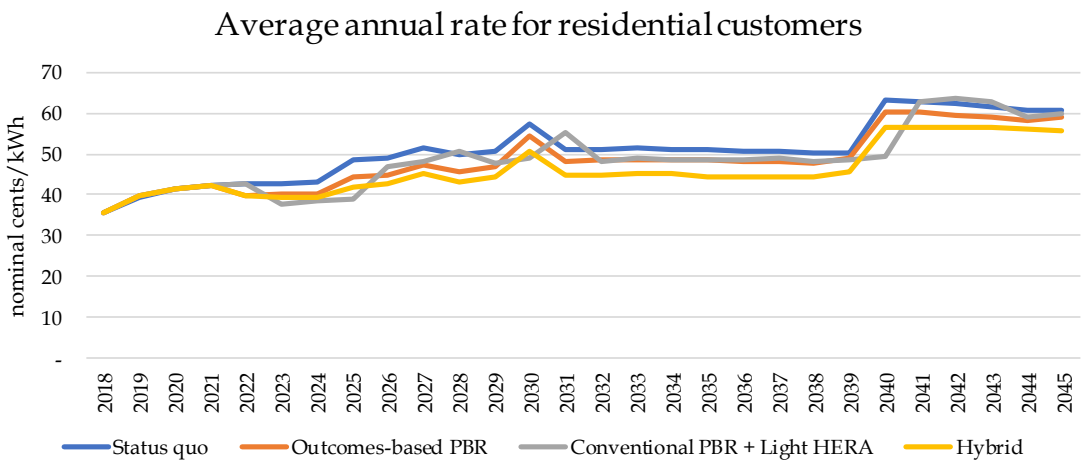
Similarly, Figure 16 illustrates the average impact that the regulatory models would have on the monthly customer bills over the forecast horizon while considering the average consumption of each customer class. For residential, commercial, and large power customers, the alternative regulatory models are anticipated to result in lower monthly bills than the status quo. These figures are also in constant 2017 dollars.

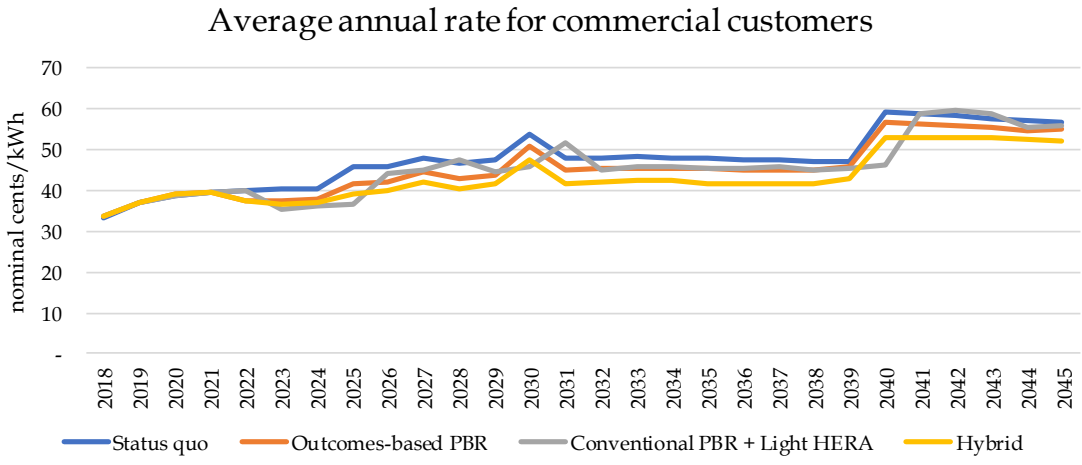
Figure 16. Projected average monthly bill over forecast horizon in Hawaii County for each regulatory model

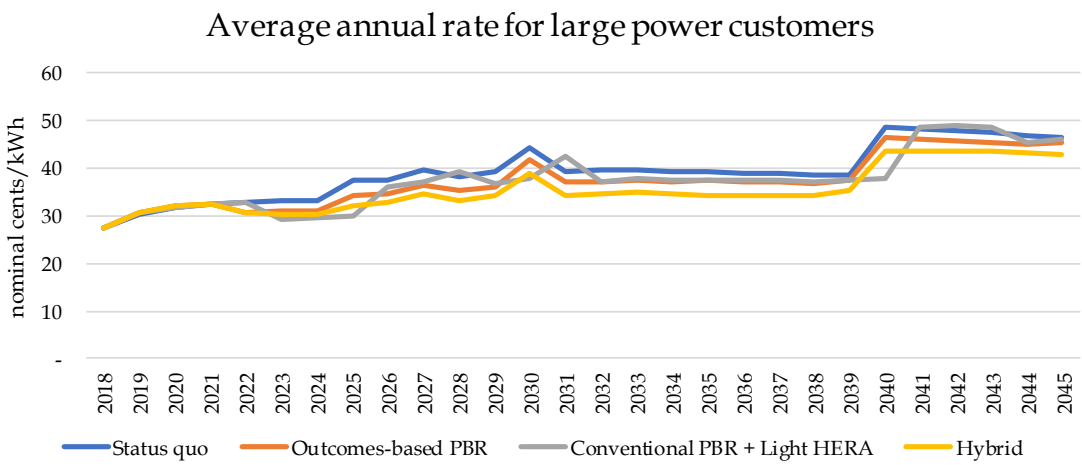
2017 dollars	Status quo	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Residential	$ 139	$ 133	$ 133	$ 127
Commercial	$ 791	$ 753	$ 756	$ 719
Large power	$ 56,406	$ 53,728	$ 53,924	$ 51,315

Furthermore, similar to other counties, the expected rates of the alternative regulatory models are lower on average as compared to the status quo. The trends in projected average annual rates under various regulatory models are similar for residential, commercial, and large power customers in that they demonstrate a general upwards growth trend throughout the forecast horizon. The average year-over-year growth in forecasted annual rates for all three customer classes from 2018 to 2045 is similar among the regulatory models, ranging between 1.8% and 2.2% with status quo being the highest.. Lastly, the graphs below show that the status quo is projected to have the highest annual rates in most of the years across the forecasted horizon for all the customer classes. On the other hand, the Hybrid model is anticipated to have the lowest annual rates in most of the years for all the customer classes. Figure 17 illustrates the forecasted annual rates for residential, commercial, and large power customers in Hawaii County (values are in nominal dollars).

Figure 17. Projected average annual rates forecast for HELCO under various regulatory models







4.2.3 MECO

4.2.3.1 Maui

Over the forecast horizon, projected average rates for the alternative regulatory models are lower than the status quo on Maui island. MECO residential customers' average rates on the island are anticipated to be around 30.3 cents/kWh under the Outcomes-based PBR and Hybrid models, and respectively 30.4 cents/kWh and 31.1 cents/kWh under the Conventional PBR with Light HERA model and the status quo. Commercial and large power rates feature a similar trend where the Outcomes-based and Hybrid models have the lowest projected average rates through to 2045, the Conventional PBR with Light HERA model results in a slightly higher average rate, and the status quo results in the highest average rate. These results are shown in Figure 18.

Note that to calculate the average rates over the forecast horizon, the Project Team first converted the forecasted rates from nominal dollars to 2017 dollars before averaging values over the forecast horizon.

Figure 18. Projected average rates over forecast horizon on the island of Maui for each regulatory model

2017 cents/kWh	Status quo	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Residential	31.1	30.3	30.4	30.3
Commercial	33.8	32.9	33.0	32.9
Large power	27.1	26.4	26.5	26.4

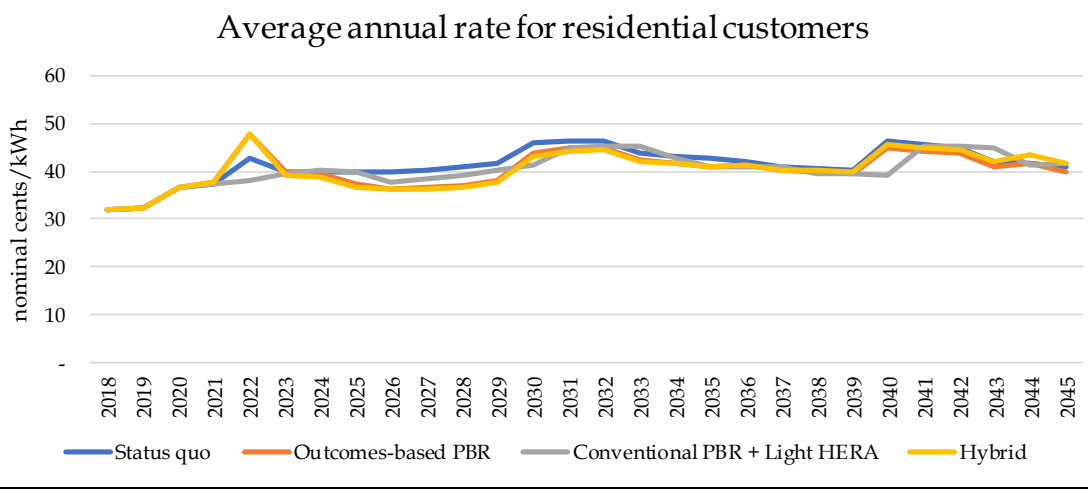
Figure 19 illustrates the average impact that the regulatory models would have on the monthly customer bills through to 2045 while considering the average consumption within each customer class. These figures are also presented in constant 2017 dollars.

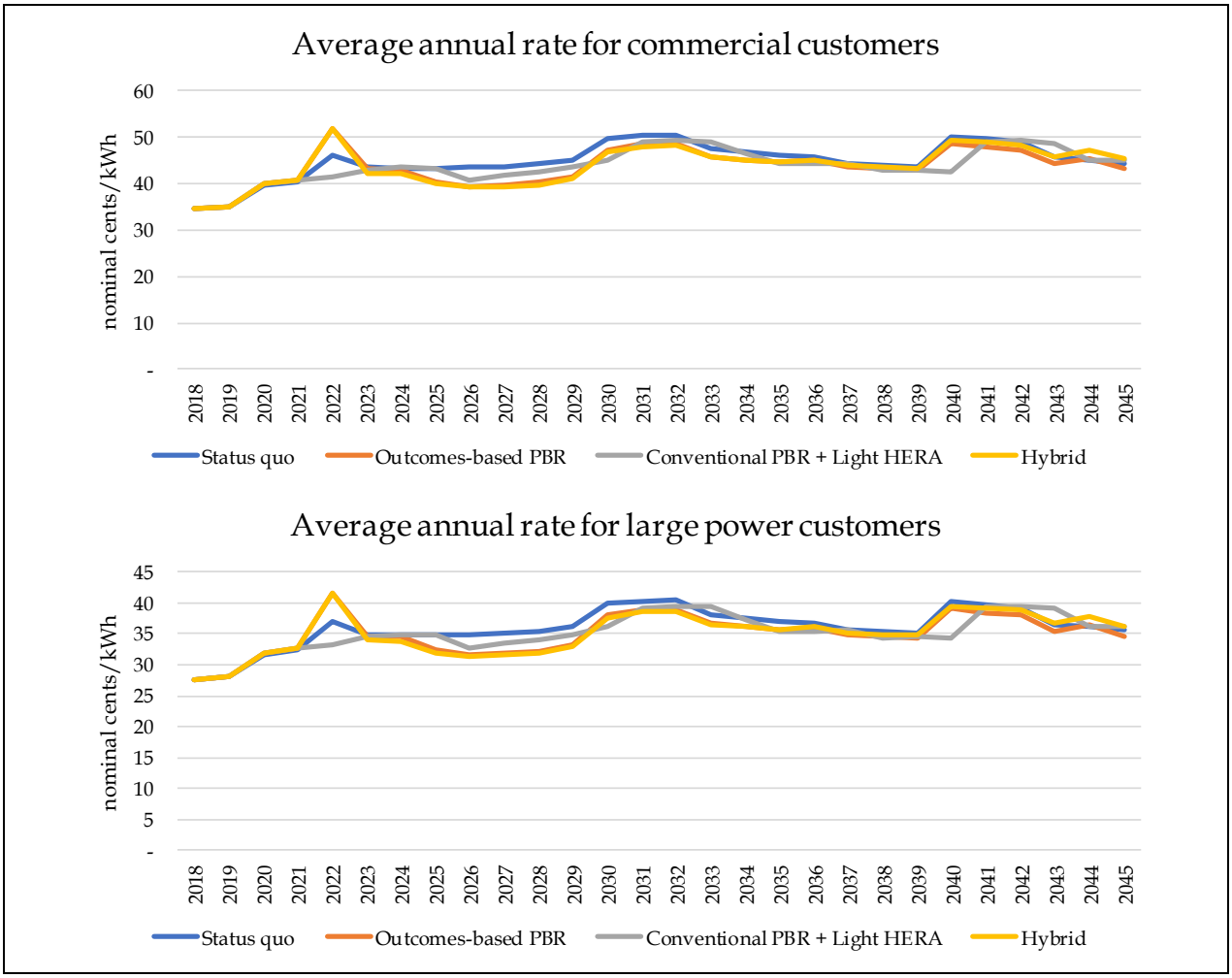
Figure 19. Projected average monthly bill over forecast horizon on the island of Maui for each regulatory model

2017 dollars	Status quo	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Residential	$ 158	$ 154	$ 154	$ 154
Commercial	$ 1,012	$ 985	$ 988	$ 987
Large power	$ 59,246	$ 57,679	$ 57,872	$ 57,796

The trends in projected average annual rates under various regulatory models are similar for residential, commercial, and large power customers in that they demonstrate a general increasing trend throughout the forecast horizon. The average year-over-year growth in forecasted average annual rates for all three customer types from 2018 to 2045 is similar across all the regulatory models, ranging from 1.1% to 1.3% with the Hybrid model featuring the highest growth. Furthermore, the graphs below show that the status quo is projected to have the highest annual rates in most of the years across the forecast horizon for all the customer classes, while the Outcomes-based PBR model is anticipated to have the lowest annual rates in most of the years for all the customer classes. Figure ***20*** illustrates the trend in rates for residential, commercial, and large power customers on the island of Maui (values shown are in nominal dollars).

Figure 20. Projected average annual rates forecast for the island of Maui under various regulatory models





4.2.3.2 Lanai

Over the forecast horizon, projected average rates for MECO residential customers on the island of Lanai are anticipated to be around 33.2 cents/kWh under the status quo, slightly higher at 33.4 cents/kWh under the Hybrid model, approximately 35.0 cents/kWh under the Outcomes-based PBR model, and the highest at 35.4 cents/kWh under the Conventional PBR with Light HERA model. Projected average commercial rates are slightly higher than the expected average residential rates. Large power rates also mimic the trends exhibited within residential and commercial rates in that they are lowest under the status quo and highest under the Conventional PBR with Light HERA model. These results are illustrated in Figure 21.

Note that to calculate the average rates over the forecast horizon, the Project Team first converted the forecasted rates from nominal dollars to 2017 dollars prior to averaging values over the forecast horizon.

Figure 21. Projected average rates over forecast horizon on the island of Lanai for each regulatory model

2017 cents/kWh	Status quo	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Residential	33.2	35.0	35.4	33.4
Commercial	34.9	36.8	37.2	35.1
Large power	28.1	29.6	29.9	28.3

Figure 22 illustrates the average impact that the regulatory models would have on monthly customer bills throughout the forecast horizon while considering the average consumption within each customer class. The three alternative regulatory models are projected to have higher average monthly bills than the status quo. These figures are also in constant 2017 dollars.

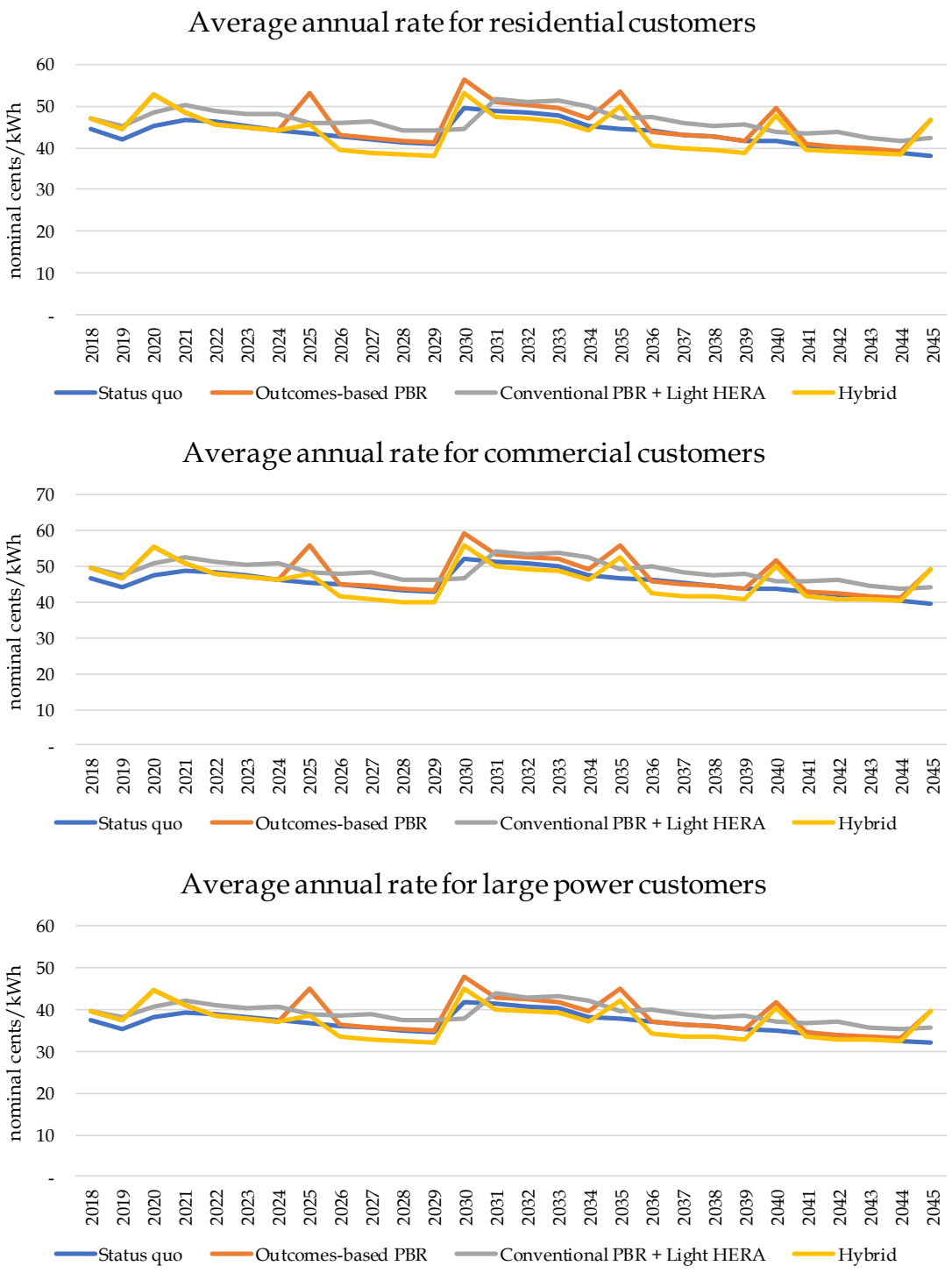
Figure 22. Projected average monthly bill over forecast horizon on the island of Lanai for each regulatory model

2017 dollars	Status quo	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Residential	$ 129	$ 136	$ 138	$ 130
Commercial	$ 963	$ 1,015	$ 1,026	$ 969
Large power	$ 96,276	$ 101,462	$ 102,603	$ 96,872

The trends in projected average annual rates under various regulatory models are similar for residential, commercial, and large power customers in that they demonstrate a general decreasing trend throughout the forecast horizon. The average year-over-year growth in forecasted average annual rates for all three customer types from 2018 to 2045 are respectively 0.5%, 0.7%, -0.3%, and 0.7% under the status quo, Outcomes-based PBR, Conventional PBR with Light HERA, and hybrid models.

Furthermore, the graphs below show that the Conventional PBR with Light HERA is projected to have the highest annual rates in most of the years across the forecast horizon for all the customer classes. On the other hand, the Hybrid model is anticipated to have the lowest annual rates in most of the years for all the customer classes. Figure 23 illustrates the annual rates for residential, commercial, and large power customers on the island of Lanai (values are shown in nominal dollars).

Figure 23. Projected average annual rates forecast for the island of Lanai under various regulatory models



Of note is that, unlike the other two islands in Maui County, the alternative regulatory models would result in higher average rates across all the customer classes on Lanai versus the status

quo. This is because of the higher revenue requirements under the three alternative models than under the status quo over the forecast horizon (Task 2.5.1).

Since Lanai and Molokai are smaller markets than Maui, additional PBR costs for the two islands are higher relative to the overall costs of implementing the regulatory models. As per MECO's most recent 2017 rate case, the rate of returns ("RoRs") have been adjusted for the three islands to produce their combined weighted average cost of capital ("WACC"); the RoRs are approximately 8.60% (pre-tax cut, currently around 7.5%), 6.01% and -2.49% for Maui, Lanai, and Molokai, respectively.[12] Additionally, based on historical data, Lanai and Molokai both have low totex capitalization rates (3.63% and 4.38%, respectively) compared to Maui (26.79%).[13] Combined, the smaller market sizes and lower capitalization rates lead to higher revenue requirements under the three alternative regulatory models for Lanai and Molokai. Nonetheless, due to Molokai's negative WACC, its revenue requirements are lower than for Lanai.

4.2.3.3 Molokai

Similar to Maui, the alternative regulatory models are expected to provide lower average rates than the status quo across all the customer classes. Over the forecast horizon, projected average rates for MECO residential customers on the island of Molokai are anticipated to be approximately 40.4 cents/kWh under the Outcomes-based PBR model, 40.8 cents/kWh under the Conventional PBR with Light HERA model, 41.2 cents/kWh under the Hybrid model, and 41.3 cents/kWh under the status quo. Commercial and large power rates, too, mimic the residential rates trend in that the lowest rates are found under the Outcomes-based PBR model, and the highest rates are found under the status quo. These results are shown in Figure 24.

Note that to calculate average rates over the forecast horizon, the Project Team converted the forecasted rates from nominal dollars to 2017 dollars before averaging values over the forecast horizon.

Figure 24. Projected average rates over forecast horizon on the island of Molokai for each regulatory model

2017 cents/kWh	Status quo	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Residential	41.3	40.4	40.8	41.2
Commercial	45.2	44.3	44.7	45.1
Large power	42.7	41.7	42.2	42.6

Moreover, Figure 25 illustrates the expected average impact that the regulatory models would have on monthly customer bills through to 2045, taking into account the average consumption within each customer class. These figures have been presented in constant 2017 dollars, as well.

[12] MECO. *2018 Test Year Rate Case (Docket 2017-0150).*

[13] Ibid.

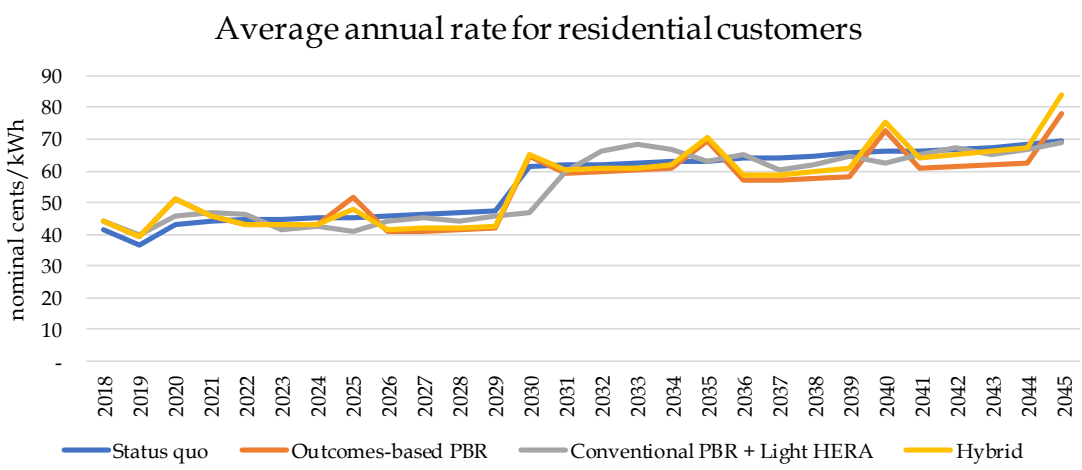
Figure 25. Projected average monthly bill over forecast horizon on the island of Molokai for each regulatory model

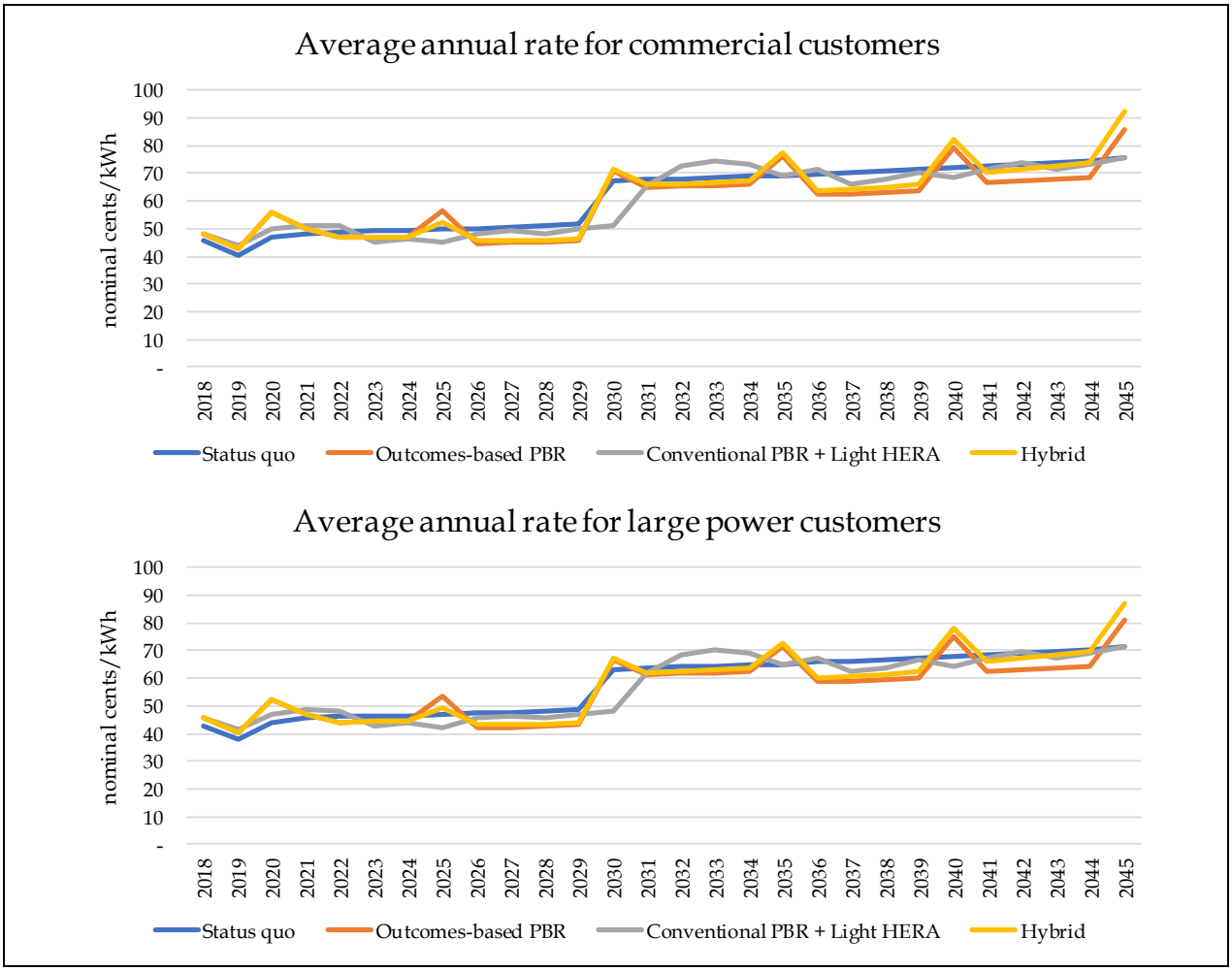
2017 dollars	Status quo	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Residential	$ 94	$ 92	$ 93	$ 94
Commercial	$ 642	$ 630	$ 635	$ 640
Large power	$ 15,579	$ 15,295	$ 15,412	$ 15,547

The trends in projected average annual rates under the various regulatory models are similar for residential, commercial, and large power customers in that they show a general upwards trend through to 2045. Compared to the other islands, the average year-over-year growth in forecasted average annual rates for all three customer types throughout the forecast horizon is more varied. The average growth in rates represents respectively 2.1%, 3.2%, 1.9%, and 3.4% under the status quo, Outcomes-based PBR, Conventional PBR with Light HERA, and Hybrid models.

Furthermore, the graphs below show that the status quo is projected to result in the highest annual rates for most years across the forecasted horizon for all the customer classes. On the other hand, the Outcomes-based PBR model is anticipated to result in the lowest annual rates for most years for all the customer classes. Figure 26 illustrates the residential, commercial, and large power rates on the island of Molokai (values shown in are nominal dollars).

Figure 26. Projected average annual rates forecast for the island of Molokai under various regulatory models





4.2.4 KIUC

On Kauai island, the alternative regulatory models are anticipated to provide slightly lower average rates than the status quo across all the customer classes. Projected average rates for KIUC residential customers over the forecast horizon are expected to be around 37.8 cents/kWh with Lighter PUC regulation, around 38.0 cents/kWh under the IGO model, and about 38.1 cents/kWh under both the status quo and HERA models. Commercial and large power rates are also impacted similarly; the lowest projected average rates are found under the Lighter PUC regulation model. These results are depicted in Figure 27.

Note that to calculate the average rates over the forecast horizon, the Project Team first converted the forecasted rates from nominal dollars into constant 2017 dollars, before averaging values over the forecast horizon.

Figure 27. Projected average rates over forecast horizon in Kauai County for each regulatory model

2017 cents/kWh	Status Quo	Lighter PUC Regulation	HERA	IGO
Residential	38.1	37.8	38.1	38.0
Commercial	37.7	37.4	37.7	37.6
Large power	33.5	33.3	33.5	33.5
Other	54.1	53.6	54.1	54.0

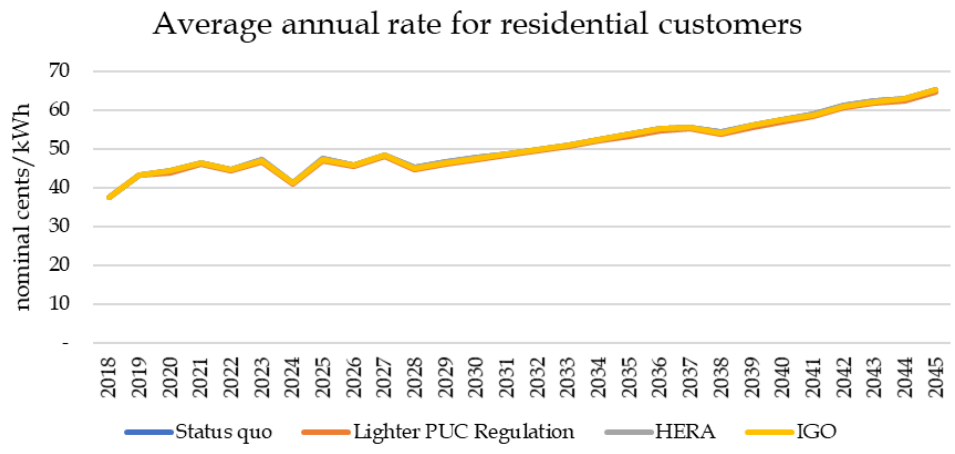
Similarly, Figure 28 illustrates the average impact over the forecast horizon that the regulatory models would have on monthly customer bills considering the average consumption within each custom class. The table shows that monthly bills are lower for Lighter PUC Regulation model and the IGO model across all customer classes while slightly higher for HERA. This is because of the overall higher revenue requirements under the HERA model. These values, too, are presented in constant 2017 dollars.

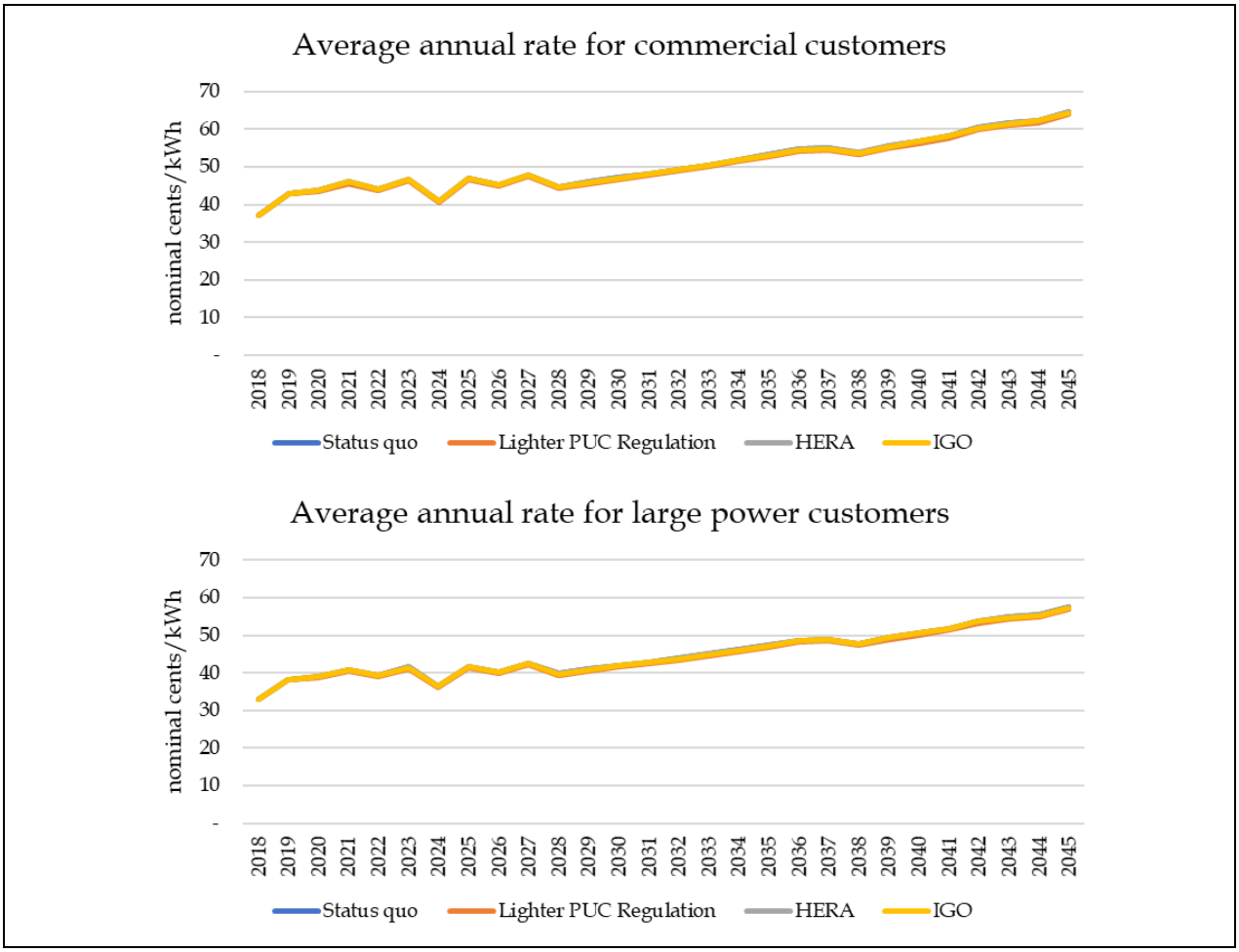
Figure 28. Projected average monthly bill over forecast horizon in Kauai County for each regulatory model

2017 dollars	Status Quo	Lighter PUC Regulation	HERA	IGO
Residential	$ 156	$ 155	$ 156	$ 156
Commercial	$ 659	$ 653	$ 659	$ 657
Large power	$ 31,644	$ 31,386	$ 31,648	$ 31,583
Other	$ 28	$ 28	$ 28	$ 28

Overall, the trends in projected average annual rates under various regulatory models are similar across the three customer classes in Kauai County as they show a general increasing trend throughout the forecast horizon. The average year-over-year growth in forecasted average annual rates for all three customer types from 2018 to 2045 is 2.2% for all status quo and alternative models. Figure 29 illustrates the rates for residential, commercial, and large power customers in Kauai County (values are in nominal dollars).

Figure 29. Projected average annual rates forecast for KIUC under various regulatory models




Average annual rate for commercial customers
nominal cents/kWh
70
60
50
40
30
20
10
-
2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
Status quo
Lighter PUC Regulation
HERA
IGO
Average annual rate for large power customers
nominal cents/kWh
70
60
50
40
30
20
10
-
2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
Status quo
Lighter PUC Regulation
HERA
IGO

5 Appendix A: Scope of work to which this deliverable responds

2.5.2. Assessment of system average retail rates for each regulatory model for an average residential, commercial, and industrial customer through 2045. CONTRACTOR shall forecast system average retail rates through 2045 using the revenue requirement from TASK 2.5.1. CONTRACTOR shall provide comparison of forecasted retail rates for each regulatory model.

DELIVERABLE FOR TASK 2.5.2. CONTRACTOR shall include its conclusions and all work to develop system average retail rates for each regulatory model. CONTRACTOR shall use the current rate structure in Hawaii as a baseline and focus on assessing the impact that the regulatory model has on average customer rates. CONTRACTOR shall include conversion of the revenue requirement each year into a fixed and variable rate component that is consistent with Hawaii's current rate, assume an average level of consumption for each category of customer, and calculate how their average system rate or aggregate bill may change through 2045 under each of the recommended regulatory models. CONTRACTOR shall provide a written summary of the findings in MS Word and an MS Excel file with rates under each regulatory model for an average residential, commercial, and industrial customer through 2045. CONTRACTOR shall submit deliverable for TASK 2.5.2 to the STATE for approval.

6 Appendix B: List of works consulted

"Cost of Service Studies." *HECO.* HECO 2017 Test Year: Direct Testimonies and Exhibits Book 10. Page 7-8.

"Energy Rate Adjustment Clause: Rate Data Sheet." *KIUC.* Effective Date: March 1, 2018. Website. <http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/rates/2018%20Rate%20Data.pdf>.

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MECO. *Annual Report of Maui Electric Company to the Public Utilities Commission State of Hawaii for the year ending December 31, 2016.* < https://puc.hawaii.gov/wp-content/uploads/2014/06/AFR-MECO-2016.pdf>

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Potential risks to utility valuation under each regulatory model

working paper prepared by London Economics International LLC for the State of Hawaii with support from Meister Consultants Group

October 9, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals; this document, which responds to Task 2.5.4, is one of several working papers associated with that engagement. It identifies potential risks to utility valuation of the different regulatory models as well as discusses the Project Team's approach to estimating the magnitude of the risks and rationale for certain assumptions. The estimates were based on previous models forecasting revenue requirements.

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List of acronyms

Capex	Capital Expenditures
CFC	Cooperative Finance Corporation
COS	Cost of Service
DBEDT	Hawaii Department of Business, Economic Development, and Tourism
DSPP	Distributed System Platform Provider
ESM	Earnings Sharing Mechanism
HECO	Hawaiian Electric Company
HELCO	Hawaii Electric Light Company
HERA	Hawaii Electricity Reliability Administrator
IGO	Integrated Grid Operator
IOU	Investor-Owned Utility
IPP	Independent Power Producer
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company
O&M	Operations and Maintenance
Opex	Operating expenditures
PBR	Performance-based Regulation
PIM	Performance Incentive Mechanism
PPA	Power Purchase Agreement
PSIP	Power Supply Improvement Plan
PSR	Platform Service Revenue
PUC	Hawaii Public Utilities Commission
RAB	Regulatory Asset Base
ROE	Return on Equity
RPS	Renewable Portfolio Standards
RUS	Rural Utilities Service
T&D	Transmission and Distribution
TIER	Times Interest Earned Ratio
Totex	Total expenditures
USDA	United States Department of Agriculture
WACC	Weighted Average Cost of Capital

1 Executive summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. The various regulatory models considered were described in previous working papers[1] and included increased oversight from a Hawaii Electricity Reliability Administrator ("HERA"), different variants of Performance-Based Regulation ("PBR"), Independent Grid Operator ("IGO"), Distributed System Platform Provider ("DSPP"), and Lighter regulation of the Kauai Island Utility Cooperative ("KIUC") by the Hawaii Public Utilities Commission ("PUC").

This working paper, which responds to Task 2.5.4 in the project scope of work, provides an estimate of the risks to utility valuations under the recommended regulatory models. It describes the Project Team's approach to estimating the value of the utilities in Hawaii.

Based on previous analyses conducted for Task 2.2.6, the recommended regulatory models analyzed for Honolulu, Hawaii, and Maui Counties were:

- status quo or the current Cost-of-Service ("COS") model for an Investor-Owned Utility ("IOU") (this is the reference case),
- an Outcomes-based PBR model,
- a Conventional PBR + Light HERA model, and
- a Hybrid model combining Outcomes-based PBR, IGO, and DSPP.

This report focuses on the three IOUs operating in Hawaii – Hawaiian Electric Company ("HECO") on Honolulu County, Hawaii Electric Light Company ("HELCO") on Hawaii County, and Maui Electric Company ("MECO") on Maui County. The three utilities are jointly referred to as "the HECO Companies" in this report. The Project Team's preliminary analysis for Kauai County indicated that KIUC's valuation was not meaningfully different under the four regulatory models for Kauai County, namely, the status quo (COS under co-op), Lighter PUC Regulation, HERA, and IGO models and therefore, an analysis of the potential risks for KIUC was not performed.

The document summarizes various categories of potential risks that were discussed in more detail in the Task 1.3.1 report. For this analysis, the Project Team focused on three categories of potential risks related to utility valuation, namely:

- financial risk, especially in terms of the risk of a credit rating downgrade,
- business risks in terms of lower electricity sales than forecast, and

[1] Such as Tasks 2.1.1, 2.2.1, and 2.2.6.

- regulatory risks based on a rate freeze during the first three years of PBR implementation and the level of rewards that the utility can earn from meeting performance targets.

The Project Team used the Discounted Cash Flow ("DCF") approach to calculate the utility valuations for each regulatory model. In the base scenario, the Team projected cash flows using the same assumptions in forecasting revenue requirements under Task 2.5.1 and estimated utility valuation by calculating the Net Present Value ("NPV") of those cash flows. The risks described above were then estimated using sensitivity analyses. Each risk was modeled as a change in an input to the DCF calculations; the resulting decrease in NPV (in percentage terms) represented the Team's estimated magnitude of that risk.

It is also important to note that there are other potential risks discussed in this report or Task 1.3.1. Some risks were not analyzed for their impact on utility valuation because they either exist in all regulatory models, or depend on particular aspects of regulatory design, or can be more easily mitigated if they arise. Since this analysis compares risks to utility valuations between the recommended regulatory models, the Project Team focused on the three categories or risks mentioned above.

In summary, the Hybrid model is riskier[2] (in terms of the three risks mentioned above) than the other models because of the uncertainty regarding Platform Service Revenues ("PSRs")[3] and its potentially major impact on utility valuation.[4] If PSRs double every ten years instead of 5, utility valuations could decrease by 2.0% to 6.4%. A rate freeze of three years is also likely to substantially depress valuation by 0.8% to 4.9%. The analysis does offer some evidence that a transition to PBR models could align utility incentives better with those of ratepayers and policymakers: lower than expected electricity sales are a smaller risk to utility valuation than lower levels of performance incentives under PBR (0.1% to 0.2% vs. 0.2% to 1.9%).

Figure 1 below provides the estimated potential decrease in valuation for the assessed regulatory models.

[2] Riskier here means higher potential magnitude of the risk – or a larger potential decline in the NPV of projected cash flows. Additional details on the risks are discussed in Section 4.

[3] Platform service revenues are earning opportunities for utility under a new business model, in which the distribution grid functions as a platform where utilities, customers, and third-party providers can transact energy and services. Utilities can take advantage of their position as the distribution service provider to generate additional revenues from services like bundled products, information sharing with DER providers, or partnering with third parties to finance home energy technologies. (Bade, Gavin. *Little less talk: With new revenue models, New York starts to put REV into action.* Utility Dive, June 2016.)

[4] All utility valuations are as of 2018 and reflect a 27-year horizon (2018-2045).

Figure 1. Potential decrease in valuations by utility, risk category, and regulatory model

($000s)	Conventional PBR + Light HERA	Outcomes-based PBR	Hybrid
Financial Risk			
Credit risk			
HECO	-	-	-
HELCO	-	-	-
MECO	-	0.8%	-
Business Risk			
Lower than expected sales			
HECO	0.1%	0.1%	0.1%
HELCO	0.1%	0.2%	0.2%
MECO	-	-	-
Slower growth of platform revenues			
HECO	N/A	N/A	2.4%
HELCO	N/A	N/A	2.0%
MECO	N/A	N/A	6.4%
Regulatory Risk			
Rate freeze for the first three years			
HECO	2.1%	2.4%	1.9%
HELCO	1.0%	0.8%	0.8%
MECO	3.1%	4.9%	3.7%
Actual rewards = half of maximum available rewards			
HECO	0.9%	0.8%	0.3%
HELCO	0.6%	0.3%	0.2%
MECO	1.2%	1.9%	0.9%

Note – valuation as of 2018 with a 27-year horizon; discount rate of 7.57%, 7.79%, and 7.43% used for HECO, HELCO, and MECO respectively.

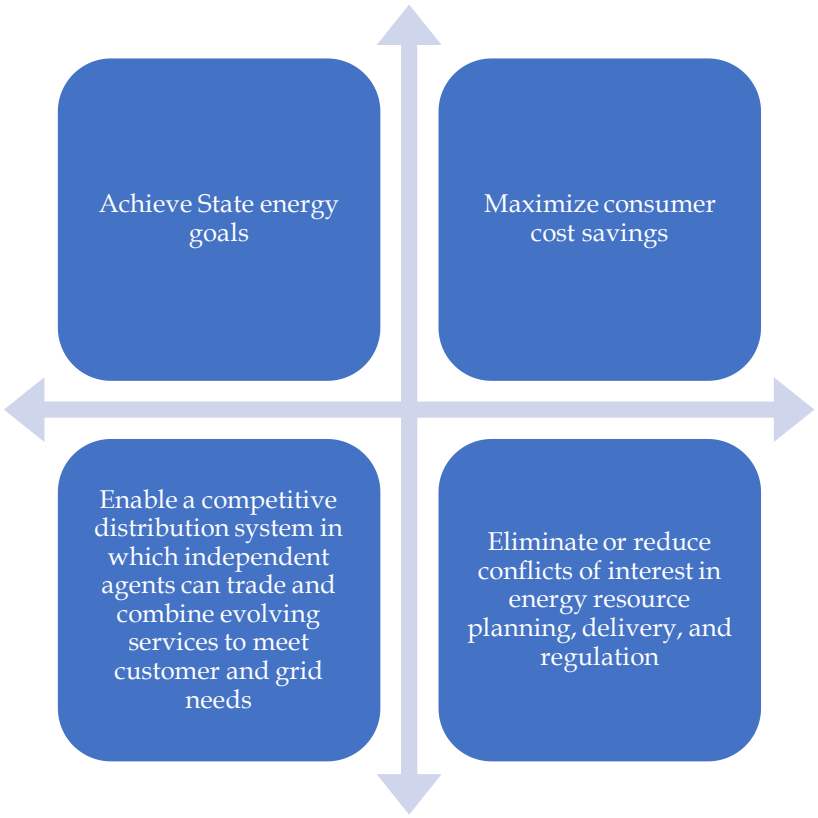
2 Introduction and scope

2.1 Project description

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission on a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[5] was contracted to perform this study.[6]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[7] listed in Figure 2.

Figure 2. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

[5] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[6] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[7] House Bill No. 1700 Relating to the State Budget.

The study will help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[8]

2.2 Role of this deliverable relative to others in the project

This deliverable is responsive to Task 2.5.4 in the project scope of work. It analyzes risks to utility valuations for the three IOUs in the State of Hawaii under four regulatory models:

- status quo – the COS model,
- an Outcomes-based PBR model,
- a Conventional PBR + Light HERA model, and
- a Hybrid model as described previously in Task 2.2.1.

Although the Project Team had evaluated four separate regulatory models for Kauai County, preliminary analysis indicated that differences in valuations of KIUC under the four models were insignificant. As mentioned in the Task 2.5.1/2.5.3 report, the differences in revenue requirements between the recommended regulatory models for Kauai County were under 1% for each year of the forecast horizon. This translated to estimates of valuation within 50 basis points for the different models. Furthermore, the risks considered for this report had nearly identical impacts on cash flows for all models because they only have minor differences in costs. This analysis, therefore, did not include KIUC and focused on the risks to valuation for the HECO Companies.

This memo discusses some of the potential risks (namely financial, business, and regulatory risks) identified and described in Task 2.3.3 in more quantitative terms and includes an approach to estimate the magnitude of the potential risks to utility valuations.

It is important to note that the analysis presented in this report is a mostly academic exercise. The Project Team's valuations and assessments of risk are based on the forecasts of revenues and expenses from revenue requirements modeling for Task 2.5.1, with assumptions of fixed capital costs and structures. All estimates also include the utilities' capital expenditures ("capex") plan from the Power Supply Improvement Plan report. In reality, capex planning and financing decisions occur in a more dynamic process. Companies may adjust the timing of investments, raise additional capital, or not pay out dividends to shareholders based on the cash available and planned usage. Given the assumptions made, the numbers should not be taken at face value. However, the analysis is useful as an indicator of potential risks in relative terms.

Furthermore, the risks and their impact on utility finances and rates can be addressed in rate case proceedings. The Project Team assumes a three-year rate cycle for the Conventional PBR model and a five-year rate cycle for the two Outcomes-based PBR models (standalone and hybrid).

[8] Hawaii Contract No. 65595. Scope of Services.

When the base rates are reset, the regulator may consider the changes in risks to the utility and authorize base revenue requirements that appropriately reflect the risk profile. The different rate cycle with various proposed models and the decisions taken by the regulators, therefore, affect risk and valuation for utilities.

3 Valuation

The valuation of a company is necessary to assess the appropriate current value or price during transactions as well as to make prudent decisions regarding investments in assets and financing those investments. The valuation analysis in Task 1.3.1 generated an estimate for the acquisition price during a change in ownership model – e.g., what price would a newly formed co-op have to pay HECO to acquire its assets. For the alternative regulatory models analyzed by the Project Team, a transfer of utility ownership from the HECO Companies or KIUC to a new entity would not be required. However, expected regulatory changes in the future can impact a utility's current value by altering its cash flows, creating uncertainty regarding earnings, and exposing it to specific business or market risks.

It is essential to understand how regulatory changes may affect a utility's value because capital flows towards investments that offer better returns, typically achieved by increases in value from the time of investment. Electric utilities and their regulators must recognize the impact of their decisions on investor returns and the utilities' risk profile. A regulatory environment that promotes value creation[9] is attractive for investors and also beneficial for all stakeholders in such a capital-intensive industry. Regulatory changes that deter investors from making investments result in higher financing costs for the utility and thus raise costs for all ratepayers. This is particularly true in Hawaii where the utilities face both a need to replace aging grid infrastructure and meet ambitious renewable energy targets. For the same reasons, "ensure utility's financial health" was a major criterion in ranking the various regulatory models in Task 2.2.6.

Common Financial Terms and Definitions

This text box outlines the key terms and definitions in the following financial analysis:

- **Discounting:** Discounting is the process of determining the present value of a future payment or a future stream of payments. Due to the time value of money, a dollar today is worth more than a dollar tomorrow. A discount factor, which is a function of time and interest rates, is applied to future dollars to determine their value today.

- **Earnings Before Interest and Tax ("EBIT"):** EBIT is simply revenues minus expenses, excluding tax and interest. It measures the profit a company generates from its operations. By ignoring tax and interest expenses, it focuses solely on a company's ability to make earnings from operations, while excluding variables such as tax burden and capital structure. EBIT is also referred to as operating earnings, operating profit, or profit before interest and taxes.

- **Earnings Before Interest, Taxes, Depreciation, and Amortization ("EBITDA"):** EBITDA is a measure of profitability. It indicates earnings prior to the impact of the tax

[9] Value creation for investors refers to factors or activities that lead to an increase in what their investment is worth. Generally, a company creates value for investors if it provides returns that are higher than the cost of capital is traditionally reflected in an appreciation of stock prices. While there are other aspects of value such as brand strength and innovation, this analysis focuses on the financial value to investors.

environment, financing decisions (or capital structure, in terms of debt versus equity), and depreciation of assets. It is calculated as the operating profit, plus the amortization expense and the depreciation expense. It is also calculated as the net profit plus interest, taxes, depreciation, and amortization.

- **Enterprise Value ("EV"):** EV indicates the total value of a firm or the total sum of all claims by both shareholders and debtholders. It is measured as market capitalization plus debt, preferred shares, and minority interest, minus total cash and cash equivalents. One common way of characterizing EV is the total value of purchasing the company in its entirety, based on share price and current debts. This is also the deal value of a merger or acquisition of the whole the target company.

- **Equity Value:** Equity value, or market capitalization, is the value of a company available to shareholders. This contrasts with EV, which also includes the value from debtholders. Relative to EV, Equity Value is EV plus total cash and cash equivalents, minus debt, preferred shares, and minority interest.

- **Free Cash Flow for the Firm ("FCFF"):** FCFF represents the cash available to investors after a company pays all its business costs, invests in current assets (e.g., inventory), and invests in long-term assets (e.g., equipment). FCFF includes bondholders and stockholders when considering the money left over for investors. FCFF is essentially a measurement of a company's profitability after all expenses and reinvestments.

- **Net Income:** Net income is the difference between revenues and cost of business, *including* all depreciation, amortization, interest, and taxes. It is not equivalent to EBITDA. It indicates the final profit that is available to shareholders.

- **Weighted Average Cost of Capital ("WACC"):** WACC is a calculation of a firm's cost of capital in which each category of capital is proportionately weighted. All sources of capital, including common stock, preferred stock, bonds, and any other long-term debt, are included in a WACC calculation. To calculate WACC, multiply the cost of each capital component by its proportional weight and take the sum of the results.

  $$WACC = (E/V) * Re + (D/V) * Rd * (1 - Tc)$$

  where,
  Re = cost of equity
  Rd = cost of debt
  E = market value of the firm's equity
  D = market value of the firm's debt
  V = E + D
  Tc = corporate tax rate

Source: Investopedia, Dictionary, see terms for "discounting," "enterprise value," "FCFF," "WACC" net income," "EBITDA," available at: https://www.investopedia.com/.

3.1 Valuation methodologies

There are several approaches to valuation commonly used in the industry, each of which is based on different assumptions about what drives value. Broadly, these approaches can be categorized into three methodologies: (i) DCF valuation, (ii) relative valuation, and (iii) contingent claim valuation.[10]

In **DCF valuation**, the company (or asset) is valued based on the present value of the cash flows it is expected to generate in the future. The future cash flows are discounted at a rate that reflects the level of risk associated with the projected cash flows. Intuitively, the DCF approach defines a company's value based on the level, timing, and volatility of cash flows that investors can expect. It can be used to value either the entire firm or just the equity stake (value to shareholders). It is based on company fundamentals such as current cash flows, the expected growth rate of those cash flows, and a company-specific discount rate. Since the fundamentals are derived from current operations, capital structure and costs, and reasonable future plans, the DCF methodology represents an estimate of the intrinsic value of a company.

In contrast, **relative valuation** estimates value based on how "comparables" (similar assets or companies, ideally in the same industry) are priced by the market. The target company is compared to the market valuations of a peer group of publicly traded companies based on standardized variables like earnings multiples, revenue multiples, or book value of assets. An alternate approach is to rely on the actual valuation of comparables reflected in recent merger and acquisition activity. Thus, instead of the fundamentals of the firm, relative valuation relies on the market's perception to determine value.

Recently, a third approach to valuation is gaining in popularity. **Contingent claim valuation** seeks to address a shortcoming in DCF valuation, which assumes a static operating strategy for the company to derive its cash flow projections. In reality, companies may change their operating strategy in response to market conditions to either take advantage of favorable developments or mitigate losses when risks materialize. The contingent claim valuation approach uses option pricing models to add an option premium to DCF valuation. A summary of the basics of option pricing theory is provided in the text box below.

Option Pricing Theory

An option is a contract that is valid for a pre-specified length of time which gives the buyer the right to buy or sell a pre-specified quantity of an underlying asset at a fixed price, called a ***strike price***. Since it is a right and not an obligation, the holder can choose to exercise the right when it is beneficial and let it expire otherwise. An option is a type of derivative security because its value is based on the underlying asset. Options can be either call or put options.

A ***call option*** gives the buyer the right to *buy* the underlying asset at the strike price. The holder would only exercise a call option when the actual asset value is higher than the strike price.

[10] Damodaran, Aswath. *Applied Corporate Finance*. New York: John Wiley & Sons, 1999. Print.

When the underlying asset's value grows, the difference between the actual asset value and the strike price also grows, increasing the value of a call option (call price).

A ***put option*** gives the buyer the right to *sell* the underlying asset at the strike price. Thus, the holder would only exercise a put option when the strike price is higher than the actual asset value. The value of a put option (put price) increases when the underlying asset's value falls.

Other factors that impact the value of an option are its strike price, the time to expiration, the risk-free interest rate, and the volatility of the underlying asset. The impact of the variables affecting call and put prices are summarized in the table below.

Factor	Call Value	Put Value
Increase in underlying asset's value	Increases	Decreases
Increase in strike price	Decreases	Increases
Increase in the variance of an underlying asset	Increases	Increases
Increase in time to expiration	Increases	Increases
Increase in interest rates	Increases	Decreases
Increase in dividends paid	Decreases	Increases

Source: Damodaran, Aswath. *Applied Corporate Finance*. New York: John Wiley & Sons, 1999. Print.

3.2 Chosen approach

The Project Team considered all three methods and selected DCF valuation for this analysis through a process of elimination. In Task 1.3.1, the Team considered both DCF and relative valuation. The analysis was more typical of valuations conducted for companies in all sectors because it considered a change in ownership. In Task 1.3.1, the Team used two types of relative valuation, trading comparables, and comparable transactions, and compared the results. The Team then verified the results of relative valuation approach after conducting a more detailed cash flow analysis for Task 1.6.2.

The Project Team believes that the limitations of the **relative valuation approach** are amplified in the context of this analysis, which involves changes in regulation rather than ownership and focuses on risks. The relative valuation approach relies on an unbiased selection of a peer group of comparables and how closely they resemble Hawaii's utilities. In Task 1.3.1, the trading comparables analysis for the HECO Companies was conducted using a peer group of 9 utilities. The initial list was narrowed down by defining the comparables as being vertically-integrated, publicly listed, and with similar levels of electricity sales and credit ratings. To estimate valuation and risks to valuation under the recommended regulatory models, even narrowing the list further to just the utilities that are subject to performance-based regulation ("PBR") regimes is not sufficient. The particular elements of PBR design such as performance targets, the magnitude of rewards and penalties in Performance Incentive Mechanisms ("PIMs"), and Earnings Sharing Mechanisms ("ESM") are key drivers of risks to utility valuation. Therefore, compiling an appropriate list of comparables is exceptionally challenging and limits the practicality of the relative valuation approach. Thus, relative valuation approach was not used.

The **contingent claims valuation approach** offers promise in its ability to incorporate the flexibility available to the utility as more information becomes available but is also hamstrung by the difficulty to obtain the data necessary for key inputs. As Hawaii moves to a 100% renewables future, utilities could adjust their resource plans if the costs of an existing technology decrease faster than expected currently or if a revolutionary new technology is developed in the future. The challenges of reliably operating a grid with a substantially higher penetration of intermittent resources may also differ from current expectations and require either higher or lower levels of investments than planned. Real options can estimate the value of the utility's ability to revise its resource or investment plans and thus improve its profitability and cash flows in the future. However, there is not sufficient information available to value them accurately given the length of the forecast horizon. Therefore, this approach was not utilized.

DCF valuation is widely used and easily accommodates sensitivity analyses. The Project Team adjusted the input parameters of its DCF models for each utility and regulatory model to reflect the risks under each recommended regulatory model and analyzed the impact on utility valuation. Section 4.1 provides a discussion of the risks and how they impact DCF models.

DCF analysis can be used to value either the entire firm (enterprise value) or just the equity's share of the company (equity value). Enterprise value ("EV") represents the value to all investors of the company – the lenders/bondholders who have fixed claims and the equity investors who have residual claims.[11] It is calculated by discounting the projected cash flows to the firm (what remains after covering operating expenses, investments, and taxes) using the company's WACC.

As a regulated utility, the HECO Companies' capital structure and rate of return to equity investors must be approved by the Public Utilities Commission ("PUC").[12] Unlike unregulated corporations, utilities cannot merely increase the company's leverage beyond a level that the PUC would allow or aggressively expand operating income to increase the value to shareholders. Utilities can benefit both their shareholders and their ratepayers by lowering risks and thus receiving more favorable terms on debt financing.[13] Therefore, this analysis estimates the various risks under the recommended regulatory models in terms of their impact on the utilities' EV to evaluate the risks to all investors. Utility valuations in this report are as of 2018 with a 27-year horizon.

3.3 Components of DCF valuation

There are three key input parameters in determining a company's value – the expected cash flows, the relevant discount rate, and an expected growth pattern. Over an extended period of time, they are also inter-related. Factors that impact the expected cash flows would likely also alter various

[11] Ibid.

[12] The Project Team assumed a fixed capital structure over the entire forecast horizon (2018-2045) for revenue requirements projections in Task 2.5.1 and the baseline valuations for this report.

[13] There is an inverse relationship between interest rates on debt and equity risk premium. See further explanations and calculations in HECO Supplemental Testimonies, Exhibits & Workpapers, Book 2, HECO ST-28, Docket No. 2016-0328, Appendix A, page 8.

profitability and liquidity ratios. If these ratios change significantly, rating agencies can revise their credit rating on the company's debt and thus impact the cost of debt. Changes in interest rate impact equity risk premium and consequently the cost of equity, as described in Section 4.1.1.

i) **Expected cash flows** in the future are discounted to estimate the utility's valuation. For an estimate of EV, the relevant cash flow metric is FCFF. It represents the cumulative cash flows to all investors, both bondholders and equity shareholders. It is calculated by subtracting tax expenses, capital expenditures ("capex"), and the change in working capital from EBIT, and adding back depreciation. These calculations are based on the projections of electricity sales, revenues, operations, and maintenance ("O&M") expenditures planned capex, depreciation, and working capital from revenue requirement calculations as discussed in Tasks 2.5.1 and 2.5.3.

ii) A **discount rate** is necessary to adjust the expected future cash flows to represent what they are worth today. The Project Team discounted the forecasted FCFF for future years up to 2045 using the utilities' WACC, as used in the revenue requirement calculations in Tasks 2.5.1/2.5.3. This discount rate is especially appropriate for this analysis since the Project Team assumed constant capital costs and structure throughout the forecast horizon in projecting revenue requirements in Tasks 2.5.1/2.5.3, as these projections formed the foundations of the analyses in this report.

iii) **Expected growth** is used to estimate cash flows beyond the forecast horizon. The Project Team's analysis includes forecasts of revenues and cash flows until 2045. Given the long useful life of utilities' physical infrastructure and a regulated natural monopoly business model, it can reasonably be expected that cash flows to the company will continue beyond 2045. Terminal value represents the value, in 2045, of the cash flows beyond the forecast horizon. An important component of estimating terminal value is the expected growth of cash flows beyond 2045. The Project Team used the growth rate estimated by JP Morgan for its valuation of the HECO Companies during the NextEra merger proceedings. JP Morgan's terminal growth rate range was 1.15% to 1.65%.[14] The Project Team used 1.40%, the average value of JP Morgan's range, in its analyses.

   Terminal value is obtained by dividing the estimated cash flow for the year after the last year of the forecast (in 2046 for this analysis) by the difference between WACC and the expected growth rate. The 2046 cash flow is calculated by multiplying the cash flow for 2045 by the growth rate.

Using the DCF approach and the same assumptions from Task 2.5.1, the Project Team estimated the NPV of FCFF as utility valuations under the base scenario. The Team then estimated the potential magnitude of some risks to utility valuation as the percentage change in the NPV of cash flows under the different scenarios reflecting each risk, as described more in Section 4.

[14] "NextEra Energy, Inc. Form S-4, Registration Statement under the Securities Act of 1993." *Securities and Exchange Commission. January 8, 2015.* Web. Accessed September 27, 2015. <https://www.sec.gov/Archives/edgar/data/753308/000119312515005172/d846219ds4.htm>

4 Risks to utility valuation

In any business and industry, companies face several risks that could impact their operations, profitability, and costs of financing. The risks could be due to macroeconomic variables that affect all companies in all industries, or new trends emerging within a particular industry, or even events that are likely to impact just a specific company. Changes in interest rates by the Federal Reserve will affect borrowing costs across the economy. Improvements in efficiency and costs for certain technologies like solar photovoltaic panels and batteries have a more focused impact on the power sector. Poor decisions by the company management regarding financing and capital investments may damage the company in question.

The risks that companies face can be thought of as having two dimensions – probability and magnitude. The likelihood of whether a particular scenario will actually become a reality is typically a qualitative assessment. The magnitude of risk has to do with the size of its impact if it does happen.

Also, the impact can be either positive or negative. For instance, there are two types of regulatory risks discussed in Section 4.1.5 – rate freezes and reward/penalty levels of PIMs. A potential rate freeze only has a downside impact, in that there is an adverse impact on cash flows and valuation from the utility's perspective. However, PIMs have both upside and downside potential, depending on whether they are symmetric or asymmetric in design. A symmetric PIM with high levels of penalties and rewards has a higher risk for the utility if it is not able to meet the performance targets; however, the potential rewards are also higher.

In contrast, lower levels of penalties and rewards imply lower downside risk for the utility but also lower upside potential. This report will only focus primarily on the potential downside of certain risks, in terms of magnitude. The qualitative assessments of these risks are provided in the Task 2.3.3 report. For this analysis, "riskier" refers to the higher potential downside in terms of magnitude – or a more significant potential decline in the NPV of projected cash flows.

4.1 Risk categories

As described in some detail in Task 1.3.1, the risks that companies face can be grouped into five categories. The risk categories along with a general example are detailed below.

Risk category	Example
Financial	A company with volatile FCFF that is not required to file audited financial statements.
Business	A company in an industry with low barriers to entry and threats to sales due to new trends in the industry.
Macroeconomic	Interest rate hikes by the Federal Reserve lead to higher borrowing costs for all companies.
Operational	The development of a new technology forces existing companies to change their business models.
Regulatory	Introduction of new regulations regarding environmental standards.

4.1.1 Financial risk

Financial risk pertains to the level of uncertainty regarding a company's cash flows. They are affected by a company's expected revenues, capital structure, costs of financing, ongoing operating expenses, and planned capital expenditures. Various financial ratios regarding profitability, leverage, and liquidity are monitored to evaluate this risk. In the base scenario, the utilities' capital structures and costs are assumed to be fixed throughout the forecast horizon. However, due to differences in revenues and expenditures under different regulatory models, profit margins and leverage ratios vary across different models. Financial risk evaluates several characteristics regarding cash flows, including the uncertainty, timing, dependence on the accounting method used, and the level of oversight (such as from an auditor, shareholders, or the US Securities and Exchange Commission).

Several measures can help address financial risk. Regulatory accounting allows utilities to defer some expenses and revenues to match the timing of their inclusion in revenue requirements and rates. This helps to smoothen out any volatility. Also, utilities can be shielded from risks regarding variation in fuel and purchased power costs by including adjustments in the final revenue requirements that allow them to fully recover these costs through rates. Finally, profitability and leverage analyses help to assess the level and volatility of cash flows. Rating agencies evaluate all factors for the company against its industry peers to evaluate financial risk. Higher levels of risk are typically reflected in lower credit ratings and higher costs of capital.

Financial risk, as reflected in a change in the cost of capital, could impact all three components of DCF valuation. The utility's expected cash flows are directly affected because the operating income component of revenues is obtained by multiplying the rate base by WACC. Depending on the timing of the change in WACC, it may justify using a different discount rate than the base WACC. While the growth rate would not change, a change in WACC would alter the terminal value used in the valuation.

The HECO Companies are currently rated BBB- by S&P and Baa2 by Moody's, indicating a medium credit quality.[15] Both ratings companies also have a "stable" outlook for HECO's credit ratings. Some of the financial metrics associated with the credit ratings as well as the corporate yields, or cost of debt, are shown in Figure 3. In estimating the financial risks to utility valuation, the Project Team compared the financial ratios of the HECO Companies over the forecast horizon under each regulatory model. If the ratios deteriorated, the Project Team assumed that the cost of debt would increase by a certain amount as shown in the last column in Figure 3.

[15] S&P Global Market Intelligence. *Corporate Issuance – Credit Ratings*. Accessed September 30, 2018.

Figure 3. Financial ratios and interest rates by credit rating

Credit Rating	EBITDA/Interest Expense	EBITDA Margin	Operating Margin	Interest Coverage	Interest rate on senior debt	Interest rate - Δ vs. Baa
Aaa	11.5	30.6%	25.4%	16.0	4.53%	0.74%
Aa	13.9	19.5%	17.4%	16.0	4.70%	0.57%
A	10.7	15.8%	14.9%	8.6	4.97%	0.30%
Baa	6.3	13.9%	12.0%	5.4	5.27%	0.00%
Ba	3.7	13.3%	11.5%	3.7	6.90%	(1.63%)
B	1.9	11.2%	9.0%	1.9	10.38%	(5.11%)
Caa-C	0.7	7.0%	4.6%	0.7	12.92%	(7.65%)
HECO	6.3	19.0%	10.8%	3.6	3.25% - 6.50%	
HELCO	7.1	25.3%	13.7%	3.9	3.10% - 6.50%	
MECO	6.5	19.1%	12.0%	4.1	3.10% - 5.65%	

Source: HECO Annual Financial Report to the PUC 2017. Moody's Data Report, September 2017. S&P Capital IQ.

A change in the cost of debt also leads to a change in the equity risk premium and hence the cost of equity. The relationship between equity risk premium and the cost of debt is denoted by the following equation:[16]

$$Equity\ Risk\ Premium = -0.5755 * Cost\ of\ debt + 0.0775$$

Based on the above formula and the assumption that the capital structure remains fixed, the cost of capital for each credit rating is shown in Figure 4.

Improvements in the risk profile and credit ratings result in relatively small decreases in WACC whereas a ratings downgrade has a much more significant and negative impact on WACC. The Project Team estimates that an "Aaa" credit rating would lower HECO's WACC by 47 basis points, but a downgrade to a "Ba" rating could increase its WACC by nearly 100 basis points. The downside risk is much higher than the upside because the HECO Companies' current rating is towards the lower end of the "Investment Grade" ratings. Investment grade indicates that the entity is likely to meet payment obligations on its debt issuances and includes ratings of BBB- or higher by S&P or Baa3 or higher by Moody's. As certain financial institutions are only allowed to invest in investment grade securities, it is important to ensure that the HECO Companies' credit rating does not fall into the "junk bond" category.

Figure 4. Cost of capital by credit rating - Indicative

Credit Rating	Corporate Yields - 30 year	Corporate Yields - Δ vs. Baa	ROE	WACC		
				HECO	HELCO	MECO
Aaa	4.53%	(0.74%)	9.19%	7.10%	7.32%	6.97%
Aa	4.70%	(0.57%)	9.26%	7.21%	7.43%	7.08%
A	4.97%	(0.30%)	9.37%	7.38%	7.60%	7.24%
Baa	5.27%	0.00%	9.50%	7.57%	7.79%	7.43%
Ba	6.90%	1.63%	10.19%	8.61%	8.84%	8.46%
B	10.38%	5.11%	11.67%	10.83%	11.08%	10.65%
Caa-C	12.92%	7.65%	12.75%	12.46%	12.71%	12.24%

[16] HECO. *Docket No. 2016-0328. Supplemental Testimonies, Exhibits & Workpapers – Book 2. HECO ST-28, Appendix A.* p8.

4.1.2 Business risk

Business risk pertains to factors affecting the utility's profits through either revenues or expenses. As a regulated monopoly, utilities are less exposed to business risks arising from competition or fluctuations in commodity prices than a typical company. However, utilities in many jurisdictions are increasingly facing the threat of flat or declining load (or sales). If actual electricity sales in Hawaii are lower than forecasted, it would also impact cash flows and valuation. There will be an impact even if a price cap or revenue cap is used.[17] In a price cap, a fall in overall sales would mean lower revenue requirements for the utilities. A revenue cap may protect the utility from falling electricity sales within a regulatory period because revenue requirements would escalate at a fixed rate from the going-in rate. However, the forecast horizon for this analysis is over 25 years so the rates for future regulatory periods would decline relative to the base scenario. Consequently, if there is a long-term decline in sales, the utilities' revenue requirements and cash flows would decrease. Furthermore, a decrease in revenues could also lead to financial risks if the profitability and liquidity ratios decline sufficiently to warrant a credit ratings downgrade.

The Hybrid model includes an additional business risk because the Team assumes that platform service revenues ("PSR") from the DSPP model will be a significant source of utility revenues under this model. In the base scenario, the Team assumes that PSRs would double every 5 years, based on a review of the analysis presented in New York's Reforming the Energy Vision proceedings. However, this expected growth is primarily based on the potential and observed increase of similar revenues in other industries. The utilities' revenues, cash flows, and valuation are exposed to the risk that actual growth rate of PSRs will be slower than current expectations.

As mentioned previously in Section 2.2, the regulator and the HECO Companies are likely to make adjustments at the end of each rate period as new business risks become apparent.

4.1.3 Macroeconomic risk

Macroeconomic risk refers to sovereign credit rating and interest rates in the US. S&P would only rate a US-based company higher than the US if it believed that the company had sufficient creditworthiness to withstand a sovereign default by the US.[18] Since this risk category is shared across all regulatory models, it is not considered for this analysis.

4.1.4 Operational risk

Operational risks reflect the threat to the utility business due to technology change, availability of skilled labor, and environmental risks. Again, the Project Team assumes that these risks are broadly shared across all three recommended regulatory models.

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[17] For more discussion about price vs. revenue cap, please refer to Task 2.1.1.

[18] S&P Global. *General Criteria: Ratings above the sovereign – Corporate and government ratings: Methodology and Assumptions.* November 19, 2013.

4.1.5 Regulatory risk

Regulatory risks arise if the market perceives that there is a risk of change in electricity rate regulation that could affect cash flow for utilities. Although the recommended models represent a shift from the current regulatory framework, the Project Team does not evaluate those scenarios as risks but as certain changes. Often, however, changes in utility regulation are accompanied by rate freezes as regulators seek to avoid volatility to consumers during the transition. Also, elements of PBR design such as the magnitude of rewards, penalties, and ESM are not yet fixed and will likely have a major impact on the utility's profitability and risk profile. Therefore, the Project Team's analysis includes evaluation of regulatory risks of a three-year rate freeze and actual rewards for PIMs at half of the maximum level under the base scenario.

A rate freeze is a commonly used regulatory tool. In a survey of 28 states in the US, 11 employed a rate freeze.[19] The Project Team assumes that the PUC would fix rates (and therefore utility revenues) for the first regulatory period of PBR. However, the length of the regulatory period varies across the different recommended regulatory models – 3 years for Conventional PBR and 5 years for the two Outcomes-based PBR models. For the sake of consistency across the models, the Team assumes a rate freeze during the first three years once PBR is implemented, i.e., 2020 to 2022, for all regulatory models.

The Project Team's base scenario from Tasks 2.5.1 and 2.5.3 also assumes that the utilities can achieve all their performance targets and earn the maximum reward amount under each PBR model. In reality, the actual rewards earned (or penalties received) by the utility may vary based on many factors, including the level of performance targets, the utility's investment plans, and costs of different technologies. For this report, the Project Team evaluated the sensitivity of utility valuations to incremental earnings from PIMs by comparing valuations under two scenarios:

i) actual rewards earned = maximum rewards possible (base scenario), and

ii) actual rewards earned = half of the maximum rewards.

[19] Zarakas et al. *Performance Based Regulation Plans – Goals, Incentives, and Alignment.* The Brattle Group, December 2017.

4.2 Risks by regulatory model

The Project Team identified several potential risks under each recommended regulatory model. The Team then categorized those risks as either financial or business risk and made a qualitative and quantitative assessment of their potential impact on the components of DCF valuation. The potential impact of the risk on utility valuation was estimated as the change in utility valuation with respect to the base valuation. The various risks and the possible fall in utility values are summarized below in Figure 5.

The Hybrid model contains an additional risk category due to the importance of PSRs for utility cash flows. PSRs not only constitute an additional risk category but in fact the largest one. A rate freeze is also a major risk to utilities – even with deferred cost recovery after the three-year rate freeze, utility valuations are substantially lowered. Interestingly, lower than expected electricity sales represent a smaller risk to utility valuation than lower levels of performance incentives under PBR.

Figure 5. Potential decrease in valuations by utility, risk category, and regulatory model

($000s)	Conventional PBR + Light HERA	Outcomes-based PBR	Hybrid
Financial Risk			
Credit risk			
HECO	-	-	-
HELCO	-	-	-
MECO	-	0.8%	-
Business Risk			
Lower than expected sales			
HECO	0.1%	0.1%	0.1%
HELCO	0.1%	0.2%	0.2%
MECO	-	-	-
Slower growth of platform revenues			
HECO	N/A	N/A	2.4%
HELCO	N/A	N/A	2.0%
MECO	N/A	N/A	6.4%
Regulatory Risk			
Rate freeze for the first three years			
HECO	2.1%	2.4%	1.9%
HELCO	1.0%	0.8%	0.8%
MECO	3.1%	4.9%	3.7%
Actual rewards = half of maximum available rewards			
HECO	0.9%	0.8%	0.3%
HELCO	0.6%	0.3%	0.2%
MECO	1.2%	1.9%	0.9%

Note – valuation as of 2018 with a 27-year horizon; discount rate of 7.57%, 7.79%, and 7.43% used for HECO, HELCO, and MECO respectively.

4.2.1 Outcomes-based PBR model

4.2.1.1 Financial risks

In the base scenario, the financial risks (or the risk related to the utility's cash flows) under the Outcomes-based PBR model are minimal for HECO and HELCO. Both utilities are expected to maintain consistent financial performance throughout the forecast horizon. In fact, financial risk is estimated to decrease for HELCO after 2030 and for HECO after 2038 due to improving operating margins and interest coverage ratios.

For MECO, there are some financial risks between 2025 and 2030 as financial ratios deteriorate. The risk arises due to ESM – excess earnings between 2020 and 2025 are returned to ratepayers between 2025 and 2030, constraining MECO's cash flows. There is a risk of a credit downgrade during this time.

Nevertheless, since the profit margins and interest coverage ratio recover after 2030, the overall financial impact is limited. The Project Team expects a 1.63 percentage-point increase in interest rates for MECO between 2025 and 2030, also impacting the discount rate for DCF valuation. With these changes in parameters, the Team estimates that the financial risk due to ESM could lower MECO's valuation by about 0.8%.

4.2.1.2 Business risk

A potential business risk is lower electricity sales. The Project Team estimated this impact of weaker sales on utility valuation. The Team analyzed the risk to utility valuation if actual electricity sales after 2025 were 5% lower than the HECO Companies' forecast. If future sales are lower than expected, the Project Team estimates that utility valuation would decrease by 0.1% for HECO and 0.2% for HELCO but not be affected significantly for MECO. In MECO's case, lower revenues from this level of sales decline are offset by decreases in O&M and tax expenses. This difference relative to HECO and HELCO is driven by the particular mix of revenues, expenses, and planned capex.

4.2.1.3 Regulatory risk

As described in Section 4.1.5, the Project Team considered two types of regulatory risks: rate freezes and the level of rewards and penalties under the PIMs.

The impact of a rate freeze on utility valuation was substantial. If the PUC imposed a three-year rate freeze during the first PBR generation (or between 2020 and 2022) with no provisions for the utility to recover expenses in the interim, the utilities could lose over 10% of their value. Even if the utilities are allowed to recover the difference between frozen rates and actual revenue requirements throughout 5 years after the rate freeze, there is still a significant regulatory risk. With a delayed cost recovery, a three-year rate freeze could lower utility valuation by about 2.4% for HECO, 0.8% for HELCO, and 4.9% for MECO. In practice, utilities would adjust expenditures and capex plans in response to a rate freeze and the impact on cash flows and valuation would be more limited.

Another regulatory risk considered in this analysis is the level of rewards and penalties in PIMs. It is not sufficient to merely set performance targets that are achievable – the corresponding

rewards and penalties must also be high enough to incent the utility to manage its operations such that those targets are indeed achieved. Over the course of time, even small changes in incentive levels can have a significant impact on the utilities' valuations. If the utilities are only able to earn half of the available incentives, utility valuations would decline by $26.8 million for HECO, $3.0 million for HELCO, and $12.3 million for MECO.

4.2.2 Conventional PBR + Light HERA model

4.2.2.1 Financial risks

Compared to the two Outcomes-based PBR models, the impact of ESM is typically more limited under Conventional PBR because the revenue cap mechanism helps to limit excess utility earnings. The profitability and leverage ratios deteriorate for some isolated years but recover immediately after. As a result, the Project Team does not expect additional financial risks or a need to adjust the costs of capital under this model. Therefore, the Project Team does not assume financial risks to significantly impact utility valuations under the Conventional PBR + Light HERA model.

4.2.2.2 Business risk

If electricity sales after 2025 are 5% lower than expected, utility valuation would decrease by 0.1% for both HECO and HELCO but not be affected significantly for MECO. In MECO's case, lower revenues from this level of sales decline are offset by decreases in O&M and tax expenses. Furthermore, business risk is lower under the Conventional PBR + Light HERA model compared to the Outcomes-based PBR model because it already includes a revenue cap mechanism that limits revenues and cash flows regardless of load growth.

4.2.2.3 Regulatory risk

Again, a three-year rate freeze with no provisions for deferred cost recovery could lower the utilities' valuation by 10%. If deferred cost recovery is allowed, a three-year rate freeze could lower utilities' valuation by about 2.1% for HECO, 1.0% for HELCO, and 3.1% for MECO. Generally, the risk of a rate freeze is lower under this regulatory model compared to the two Outcomes-based PBR models because it includes a revenue cap mechanism that limits the increase in customer rates.

If actual earnings from performance incentives are only 50% of the maximum available rewards, utility valuations decline by 0.9% for HECO, 0.6% for HELCO, and 1.2% for MECO.

4.2.3 Hybrid model

4.2.3.1 Financial risks

Financial risks under the Hybrid model are minimal in the base scenario for HECO and HELCO. The utilities' profitability and leverage ratios generally improve under this regulatory model with respect to the status quo. The reduction in costs associated with system operations and dispatch as well as additional infrastructure investments to enable the DSPP result in additional positive cash flows.

4.2.3.2 Business risk

If electricity sales after 2025 are 5% lower than expected, utility valuation would decrease by 0.1% for HECO and by 0.2% for HELCO but not be affected significantly for MECO. Another business risk under the Hybrid model is the assumed growth of PSRs. In the base case, PSRs are assumed to double every 5 years after the DSPP component is introduced. If PSRs only grow half as fast, the Project Team expects valuations to decrease by about 2.4% for HECO, 2.0% for HELCO, and 6.4% for MECO. This indicates a need to carefully craft the PIMs and transition to the DSPP component after the potential of platform-based markets and associated revenues to the utility is more fully understood. However, it is also important to note that the utility and regulators can adapt their responses to actual growth in PSRs relative to the current expectations.

4.2.3.3 Regulatory risk

A three-year rate freeze with no provisions for deferred cost recovery could lower the utilities' value by about 15%. If deferred cost recovery is allowed, a three-year rate freeze could reduce utility valuation by about 1.9% for HECO, 0.8% for HELCO, and 3.7% for MECO.

50 % lower earnings from performance incentives compared to the base scenario would lower utility valuations by 0.3% for HECO, 0.2% for HELCO, and 0.9% for MECO.

5 Appendix A: Scope of work to which this deliverable responds

2.5.4 Analysis of any issues in the regulatory model that could impact the valuation of an electric utility and identify key risks to utility valuations for each regulatory model. CONTRACTOR shall provide an analysis of any variation to the valuation of an electric utility caused by a change in regulatory model.

DELIVERABLE FOR TASK 2.5.4. CONTRACTOR shall provide its conclusions and all work related to an analysis of issues in the regulatory model that could impact the valuation of an electric utility. CONTRACTOR shall assess key risks to utility valuations for each recommended regulatory model and develop an approach to estimate the magnitude of these risks. CONTRACTOR shall include a written summary of the findings in MS Word and Power Point. CONTRACTOR shall submit deliverable for TASK 2.5.4 to the STATE for approval.

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Identification of funding mechanisms for each regulatory model

prepared for the Hawaii Department of Business, Economic Development & Tourism ("DBEDT") by London Economics International LLC

September 28, 2018

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This document, Task 2.5.5, is one of several working papers issued as part of this engagement. It provides an overview of the funding mechanisms for three alternative regulatory models to the status quo: Outcomes-based performance-based regulation ("PBR"), Conventional PBR with Light Hawaii Electric Reliability Administrator ("HERA"), and Outcomes-based PBR with the Distributed System Platform Provider ("DSPP") and Independent Grid Operator ("IGO").

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List of acronyms

BQDM	Brooklyn-Queens Demand Management
CAISO	California ISO
Capex	Capital expenditure
CFC	Capital Funding Chart
ConEd	Consolidated Edison
DBEDT	Hawaii Department of Business Economic Development and Tourism
DCA	Division of Consumer Advocacy
DER	Distributed energy resource
DSO	Distribution system operator
DSP	Distributed System Platform
DSPP	Distributed System Platform Provider
EAC	Early Amortization Charge
EAM	Earnings Adjustment Mechanism
EAS	Energy Administration Service
EAWCC	Early Amortization Working Capital Charge
EPSFC	Early Payment Shortfall Funding Charge
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
HECO	Hawaiian Electric Company
HEI	Hawaiian Electric Industries
HELCO	Hawaii Electric Light Company
HERA	Hawaii Electric Reliability Administrator
IGO	Independent Grid Operator
ISO	Independent system operator
ISO Tariff	ISO New England Inc. Transmission, Markets, and Services Tariff
ISO-NE	ISO New England
LEI	London Economics International LLC
LSE	Load Serving Entity
MECO	Maui Electric Company
MPIR	Major Project Interim Recovery
MS	Market Support
NERC	North American Reliability Corporation
NY PSC	State of New York Public Service Commission
NYISO	New York ISO
O&M	Operating and maintenance
OATT	Open Access Transmission Tariff
Opex	Operating expenditure
PBR	Performance-based regulation
PIM	Performance incentive mechanisms

PJM	PJM Interconnection
PSR	Platform Service Revenue
PUC	Public Utilities Commission
PUCT	Public Utilities Commission of Texas
RAA	Reliability Assurance Agreement
RAM	Rate Adjustment Mechanism
RAS	Reliability Administration Service
RBA	Revenue Balancing Account
RE	Reliability Entity
REV	Reforming the Energy Vision
RIIO	Revenue = Incentives + Innovation + Outputs
Totex	Total expenditure
UK	United Kingdom

1 Executive Summary

London Economics International LLC, together with Meister Consultants Group (the "Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which corresponds to Task 2.5.5 in the project scope of work, provides an evaluation of the potential funding mechanisms for three alternative regulatory models to the status quo, namely the Outcomes-based performance-based regulation ("PBR") model, the Conventional PBR with Light Hawaii Electric Reliability Administrator ("HERA") model, and the Outcomes-based PBR with the Distributed System Platform Provider ("DSPP") and Independent Grid Operator ("IGO"), or the Hybrid model. It also includes an overview of the direct and indirect cost to customers for each model.

1.1 Outcomes-based PBR

Under the Outcomes-based PBR model, the means by which utilities fund their costs would be no different than the way by which utilities recover costs under the status quo. In other words, utilities would continue to employ private financing mechanisms (i.e., short- and long-term debt, and equity), as well as cost recovery through revenue requirements. Hawaii's existing legal framework also has a series of further mechanisms in place that utilities employ to recover capital expenditures ("capex"), such as the Major Project Interim Recovery ("MPIR") adjustment mechanism, as introduced through the 2017 Decoupling Order. As such, utilities would continue to fund capex through capital markets and recover operational and financing costs through rate cases. Despite little change with regards to utilities' funding mechanisms, there would be specific impacts to cost categories that a change in the regulatory model (i.e., to the Outcomes-based PBR model) would bring. This includes a potential increase in administrative costs to utilities due to increased data gathering brought upon by Performance Incentive Mechanisms ("PIMs") and a potential increase in savings due to reduced rate cases. Further details regarding the impacts on costs can be found in Task 2.5.3 (Analysis of how costs differ under each regulatory model).

1.2 Conventional PBR with Light HERA

Under the Conventional PBR component of the proposed Conventional PBR with Light HERA model, utilities would continue to source funding as under the status quo and Outcomes-based PBR approach. With respect to the HERA component of the model, utilities would fund the change in the proposed regulatory model through a surcharge, separate from the revenue requirement of the utility, as enabled by the existing legal framework in the State of Hawaii. More specifically, under the provisions of Chapter 269 of the Hawaii Revised Statutes ("HRS"), utilities would be able to create a surcharge to be collected to fund the entity elected to be HERA.

1.3 Outcomes-based PBR with DSPP and IGO

Similar to the earlier alternative regulatory models, the utility funding mechanisms under the Outcomes-based PBR component of the Hybrid model would be no different than under the status quo. Nonetheless, under the DSPP model, utilities would be able to fund investments

related to the adoption of grid platform infrastructure and technology through including these investments in the utilities' revenue requirements. In other words, these costs would ultimately appear on the end-consumers' monthly electricity bills. That being said, the DSPP model does introduce other revenue streams for utilities aside from the traditional revenues that come with the sale of electricity. For instance, as DSPPs, utilities would also be able to earn Platform Service Revenues ("PSRs") for providing market-facing platform activities for market participants. Further, under the IGO component of the Hybrid model, additional costs would be recovered similarly to Independent System Operators ("ISOs"). Like ISOs such as ISO New England, New York ISO, and PJM Interconnection, the IGO could fund its operating expenditure ("opex") and capex through a combination of private financing and fees to market participants (which would trickle down to retail customer bills).

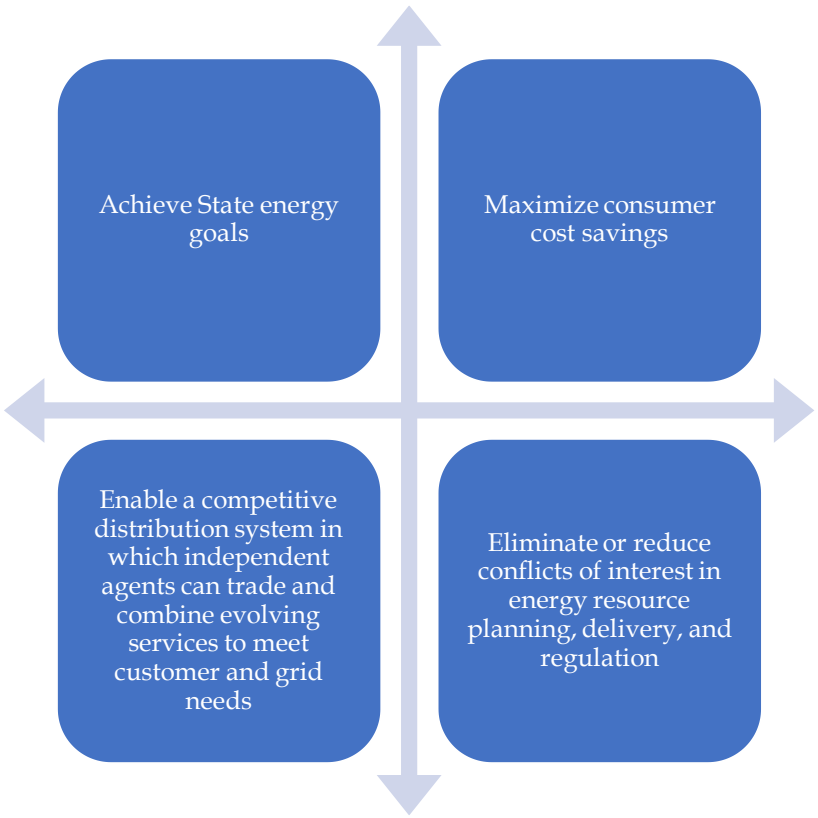
Figure 1. Summary of regulatory models' respective funding and recovery mechanisms

Regulatory model		Funding mechanism
1) Status quo		• Private financing (short- and long-term debt and equity) • Recovery through rates from customers (revenue requirements)
2) Outcomes-based PBR		• Private financing (short- and long-term debt and equity) • Major Project Interim Recovery adjustment mechanism • Recovery through rates from customers (revenue requirements)
3) Conventional PBR with Light HERA	**Conventional PBR**	• Private financing (short- and long-term debt and equity) • Recovery through rates from customers (revenue requirements)
	HERA	• Surcharge to customers (separate from revenue requirements)
4) Hybrid	**Outcomes-based PBR**	• Private financing (short- and long-term debt and equity) • Recovery through rates from customers (revenue requirements)
	DSPP	• Recovery through rates from customers (revenue requirements) and earnings from market-facing platform activities for market participants
	IGO	• Recovery through fees to market participants

2 Introduction and scope

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. LEI, through a competitive sealed proposals procurement,[1] was contracted to perform this study.[2]

Figure 2. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

The goal of the project is to assess the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[3] listed in Figure 2. The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory

[1] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[2] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[3] House Bill No. 1700 Relating to the State Budget.

models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[4]

This deliverable corresponds to Task 2.5.5 in the project scope of work. It identifies potential funding mechanisms for three alternative regulatory models to the status quo, which are Outcomes-based PBR, Conventional PBR with Light HERA, and Outcomes-based PBR with DSPP and IGO. This document also includes a brief overview of the nature of potential direct and indirect cost to customers for each model.

[4] Hawaii Contract No. 65595. Scope of Services.

3 Major cost components of electric utilities

As introduced in the Task 1.4.2 report, major cost components for an electric utility are comprised of capital costs and operating and maintenance ("O&M") costs. Since utilities need to raise capital to pay for capex, these costs can be further subdivided into the utility's expenditure on purchasing or replacing assets, and the cost of financing this spending.

Capex can take many forms. For instance, the acquisition by a utility or parent company of assets from another entity needs to be financed. The purchase price would depend on a mutually agreed-upon valuation of the assets and transaction costs. Additionally, the purchase price and terms would need to be approved by the PUC. Financing the acquisition is typically dependent on financing mechanisms available to the acquiring party (which can be an IOU, cooperative, or other entity, each with different ways of raising money), and independent of the ownership structure of the former asset owners.

Capex can also accrue without a change in ownership of utility assets. For instance, through investments in:

- new electric plant infrastructure (production, transmission, or distribution);
- fuel, materials, or supplies inventory;
- various regulatory assets; or
- any other type of investment that is amortized over multiple years.

On the other hand, O&M costs are expenses for day-to-day operations of the utility and comprised of costs associated for instance to:

- the operations and maintenance of assets;
- employee compensation and benefits;
- fuel and purchased power;
- administrative expenses; or
- taxes.

O&M expenditures are not financed. These costs are passed directly on to consumers so that they are paid for on an annual basis from revenues from power sales. In a rate case, the PUC typically determines and authorizes parameters such as the total annual revenues required by the utility to cover expenses and obtain a fair return on equity, such that the revenue requirement forms the basis to determine rates. This is discussed in detail in Task 1.6.1 working paper.

Rate cases typically include allowances for working capital, in addition to the valuation, to ensure sufficient liquidity for the financing of day-to-day operations. Working capital refers to the difference between current assets and current reliabilities; the value represents the capital that is required for short-term items (e.g., cash, inventories) needed on a day-to-day basis. The calculation is based on the average lag between accounts payable, or expenditures (e.g., employee

compensation, fuel costs, maintenance, etc.), and accounts receivable, or the number of sales billed to customers (i.e., payments that have yet to be made).

State of Hawaii Public Utilities Commission funding mechanisms

The State of Hawaii Public Utilities Commission ("PUC") was established in 1913 to "*protect the public interest by overseeing and regulating public utilities*," ensuring that the service provided is reliable and the rates charged are reasonable. In Hawaii, the PUC regulates electricity, gas, telecommunications, water carriers, and motor carriers' transportation, as well as water and wastewater service entities. While the implementation of all three regulatory models, namely the Outcomes-based PBR, Conventional PBR with Light HERA, and Outcomes-based PBR with DSPP and IGO models, will affect the Hawaii PUC's costs, the funding mechanisms the Commission utilizes to recover its costs should remain the same.

For the recovery of direct expenses incurred, the Commission utilizes the Special Fund. All fees and revenues that the Hawaii PUC collects are deposited into said Special Fund, and consequently administered by the PUC itself, and used to cover all opex incurred by the PUC, as well as the Division of Consumer Advocacy ("DCA"), Department of Commerce and Consumer Affairs. The Special Fund begins with a balance of $1 million at the beginning of each year, carried over from the previous fiscal year. Any amounts above $1 million at the end of the fiscal year are transferred over to the General Fund.

Fees and revenues collected and consequently deposited into this Special Fund include Public Utility Fees; public utilities pay annual fees of 0.5% of their gross income from the previous year's business, paid semi-annually (i.e., 0.25% in July and 0.25% in December). Motor carriers, too, pay annual fees of 0.25% of their gross income in the previous year of business. Special Fund revenues also include filing fees, duplication fees, interest and penalties, and One Call Center fees.

In 2017, the Special Fund's revenues were derived from Public Utility Fees (89.79%); Motor Carrier Fees (9.13%); Hawaii Motor Carrier Interest, Penalties, and Fines (0.42%); Hawaii One Call Center Fees (0.37%); and Filing Fees and Other Revenues (0.29%). As such, the 2017 Special Fund revenues totaled approximately $19.15 million. Total 2017 direct expenditures, on the other hand, amounted to roughly $6.23 million, thereby accounting for approximately 33% of expenditures from the Special Fund. The remaining 67% of the Special Fund expenditures comprised of transfers to State agencies or the General Fund, as well as expenditures on PUC personnel.

While PUC funds its operations through market participants, the aforementioned Public Utility Fees eventually trickle down to retail electric customers. These charges are not listed as a surcharge but rather built into the revenue requirements of the utilities.

Source: State of Hawaii Public Utilities Commission. *Annual Report for Fiscal Year 2017.* <https://puc.hawaii.gov/wp-content/uploads/2017/12/PUC-Annual-Report-FY2017.pdf>; "Introduction." *State of Hawaii Public Utilities Commission.* Web. September 11, 2018. <http://puc.hawaii.gov/about/introduction/>; HECO Direct Testimonies & Exhibits Book 10

4 Status Quo

Under the status quo, utilities recover their opex or capex through a traditional Cost-of-Service ("COS") regime which has been supplemented with different mechanisms to incentivize utility performance, such as Performance Incentive Mechanisms ("PIMs"), Earning-Sharing Mechanism ("ESM"), or revenue decoupling. Details of costs under this regulatory model are provided in Task 2.5.3 (Analysis of how costs differ under each regulatory model).

The parent company of Hawaiian Electric Company ("HECO"), Hawaii Electric Light Company ("HELCO"), and Maui Electric Company ("MECO") (i.e., "the HECO Companies"), Hawaiian Electric Industries, Inc. ("HEI"), finances its capex through a combination of debt (short- and long-term) and equity (e.g., stock).[5] While no such amounts were outstanding as of December 31, 2017, HEI occasionally makes short-term loans to HECO to meet HECO's cash requirements, including funding its own loans to HELCO and MECO.

In 2017, HECO's capital structure was comprised of 42% long-term debt (net), 1% preferred stock, and 57% common stock equity.[6] According to HEI's *2017 Annual Report to Shareholders*, HECO utilizes short-term debt (e.g., commercial paper) to finance normal operations, as well as to refinance short-term debt and other temporary requirements. As mentioned above, HECO periodically borrows from HEI not only for itself but for HELCO and MECO, as well. HECO also regularly makes or takes short-term loans to and from HELCO and MECO; these cross-utility loans are eliminated in the consolidation of HECO's financial statements. Furthermore, to fund capital improvement projects or to repay short-term loans used to fund capital improvement projects, the utilities "*utilize long-term debt, borrowings of the proceeds of special purpose revenue bonds…issued by the Department of Budget and Finance of the State of Hawaii[,] and the issuance of privately placed unsecured senior notes bearing taxable interest.*"[7] HECO has a $200 million line of credit facility.

Further, utilities in Hawaii fund their opex and financing costs for specific capex through rate cases; put differently, these costs are passed to the ratepayers such that the utilities can pay for their costs annually through revenues from energy sales. Unless otherwise agreed to, electric utilities in Hawaii are "*required by PUC order to initiate a rate proceeding every third year (on a staggered basis)*," thereby allowing the Commission and DCA to evaluate decoupling.[8] This also allows utilities to request a level of revenue requirement such that they are able to recover their operating costs, as well as financing costs for certain capital costs (i.e., cost of plant and equipment, cost of new capital projects to ensure or improve service reliability, and the cost of new capital projects to increase renewable energy implementation). For capital project costs

[5] HEI. *2017 Annual Report to Shareholders.* Page 46.
<https://issuu.com/heihawaii/docs/hawaiian_electric_industries_2017_a?e=9369327/59600119>

[6] Ibid, page 60.

[7] Ibid, page 60.

[8] Ibid, page 60.

beyond the Commission's cost cap, utilities can recover their costs through cost recovery mechanisms other than base rates, such as through the recently established Major Project Interim Recovery ("MPIR") adjustment mechanism, as introduced on April 27, 2017, through the 2017 Decoupling Order.[9]

The MPIR mechanism allows projects with capex net of customer contributions over $2.5 million, including renewable energy, energy efficiency, utility-scale generation, grid modernization, and other projects to recover revenues for net costs "*placed in service between general rate cases wherein cost recovery is limited by a revenue cap and is not provided by other effective recovery mechanisms.*"[10] The MPIR mechanism also allows for the recovery of approved accrued revenues upon the specified project's in-service date to be collected from ratepayers through the annual Revenue Balancing Account ("RBA") tariff.[11] Conversely, those capital projects that are not eligible for cost recovery through said MPIR mechanism would instead be included in the Rate Adjustment Mechanism ("RAM") and thus be subject to the RAM cap in the interim; utilities would then be able to request the recovery of said capital costs through its base rates in the next rate case.[12]

Through the 2017 Decoupling Order, the PUC also establishes the recovery of fuel and purchased energy expenses to be done through a modified energy cost adjustment mechanism as opposed to through base rates; the PUC will also "*consider adopting processes to periodically reset fuel efficiency measures embedded in the energy cost adjustment mechanism to account for changes in the generating system.*"[13]

[9] Ibid, page 121.

[10] Ibid, page 122.

[11] The Revenue Balancing Account Rate Adjustment is a charge or credit approved by the Public Utilities Commission under a new method of setting electric rates called decoupling, which supports Hawaiian Electric's clean energy efforts. (Source: "Understanding Your Bill." *HEI.* Web. September 19, 2018. <https://www.hawaiianelectric.com/billing-and-payment/understanding-your-bill/understanding-elements-of-your-bill>)

[12] HEI. *2017 Annual Report to Shareholders.* Page 122.
<https://issuu.com/heihawaii/docs/hawaiian_electric_industries_2017_a?e=9369327/59600119>

[13] Ibid, page 122.

5 Outcomes-based PBR

Under the Outcomes-based PBR model, like the United Kingdom's ("UK") Revenue = Incentives + Innovation + Outputs ("RIIO") model, the focus is on incentivizing specific outcomes by providing utilities flexibility in producing the results. Further details on the Outcomes-based PBR model can be found in Task 2.1.1 (Review of potential regulatory models that could be applied in Hawaii), Task 2.2.1 (Preliminary and high-level evaluation of the regulatory models relative to Hawaii State's goals), and Task 2.2.6 (Identification and recommendation for the three most beneficial regulatory models for further consideration).

All costs related to the implementation of the Outcomes-based PBR model would be borne by the utility, and therefore be passed as operational spending. While the method for setting the level of revenue requirements and rates, as described in the previously referenced Tasks, is different under the Outcomes-based PBR regulatory model than it is under the status quo, the funding mechanism by which utilities recover their opex or capex would not change. Indeed, utilities would still turn to the capital markets to fund capex and recover opex and financing costs through rates.

Some of the cost categories that are impacted by the change in the regulatory model include, for instance, an increase in administrative costs for the utility to gather and file data required to support expanded performance incentive mechanisms ("PIM"), or increased costs related to the PBR rate-setting proceedings. Conversely, the longer regulatory periods of five (5) years that come with an Outcomes-based PBR model (relative to the status-quo) would lead to fewer rate cases, and thus, increased savings for both the utilities and the PUC. Details of costs under this regulatory model are provided in Task 2.5.3 (Analysis of how costs differ under reach regulatory model).

Changes in costs to the State of Hawaii Public Utilities Commission

With the implementation of the new regulatory model, the means by which the Hawaii PUC funds its costs should remain the same (see *State of Hawaii Public Utilities Commission funding mechanisms* box in Section 3). Nonetheless, the Commission may see an increase or decrease in costs, as follows:

- The PUC may need to hire consultant(s) to provide expertise pertaining to the implementation of the proposed regulatory models. This may lead to an increase in costs.
- The implementation of models that increase oversight of the PUC, such as the Outcomes-based PBR variant, may necessitate increased administrative costs. For instance, expanded PIMs may require increased coordination and thus increased staffing to assess utilities' targets and achievements at the end of the regulatory period, resulting in overall higher costs.
- Nonetheless, with the implementation of PBR models, the regulatory period would likely be lengthened from the status quo (from three to five years), thereby requiring fewer rate cases. This would lead to increased savings for both the PUC and the utilities.

6 Conventional PBR with Light HERA

The Conventional PBR with Light HERA model will employ the indexing formula of the Conventional PBR alongside a light adoption of the HERA model; this combined model is discussed in further detail in Task 2.2.1 (Preliminary and high-level evaluation of the regulatory models relative to Hawaii State's goals) and Task 2.2.6 (Identification and recommendation for the three most beneficial regulatory models for further consideration).

The implementation of the Conventional PBR with Light HERA may induce changes in costs to the utility, as well. Unlike the Outcomes-based PBR model, the Conventional PBR model would maintain the current regulatory period of three (3) years, fewer PIMs (relative to the Outcomes-based PBR), and no requirement to file capital and asset management plans, thereby decreasing coordination and administrative costs on the utilities' end (relative to the Outcomes-based PBR). Further details to the impact of costs under this regulatory model are discussed in Task 2.5.3 (Analysis of how costs differ under reach regulatory model). Nonetheless, the means by which costs are recovered under the Conventional PBR would be the same as that of the Outcomes-based PBR model.

Funding for the HERA entity of the proposed regulatory model, however, would be separate from the revenue requirement of the utility. HERA would be financed through imposing a surcharge to the ratepayers, as described in the State of Hawaii's existing legal framework.

6.1 Conventional PBR

While the impact of a change of regulatory model on utilities' costs may differ under the two PBR variants, costs borne by utilities would be funded in the same way under the Conventional PBR model as under the status quo and Outcomes-based PBR approaches. In other words, utilities would continue to support their opex and capex through a combination of debt (short- and long-term) and equity and recover through rate cases (see Section **Error! Reference source not found.** for further details).

6.2 Light HERA

Under the provisions of Part IX, Electric Reliability of Chapter 269, HRS ("the HERA Law"), "*[the] Act allows for the creation of a surcharge affecting users and operators of the Hawaii electric system to be collected for the purpose of maintaining system reliability.*"[14] More specifically, under HRS Chapter 269-146, the Commission is allowed to transfer the surcharge amounts collected, in its entirety or in parts, to any entity elected to be HERA. As such, said surcharges borne by users of the Hawaii electric system would aid in funding the establishment and operations of the HERA entity.

An example of a jurisdiction which has an entity similar to HERA is Texas. In particular, the Texas Reliability Entity ("Texas RE") serves as the Electric Reliability Organization ("ERO") for the State of Texas, and as such is responsible for monitoring the reliability standards within the Electric

[14] HRS Chapter 269-146. *Hawaii electricity reliability surcharge; authorization; cost recovery.* HI Rev Stat § 269-146 (2017).

Reliability Council of Texas ("ERCOT") territory. Texas RE is a not-for-profit corporation which, via an agreement formed with the North American Electric Reliability Corporation ("NERC") and approved by the Federal Energy Regulatory Commission ("FERC"), is responsible for the following:[15]

- "*Develop, monitor, assess, and enforce compliance with NERC Reliability Standards;*
- *Develop regional standards; [and]*
- *Assess and periodically report on the reliability and adequacy of the bulk power system."*

Furthermore, similar to Hawaii, Texas is not under FERC jurisdiction and like HERA, the Texas RE also funds its operations through a surcharge on the net load. Further details have been provided in the following text box.

Texas Reliability Entity's funding mechanisms

Texas RE is a voluntary organization with membership open to any entity that qualifies (i.e., any entity that is a user, owner, or operator in the ERCOT region bulk power system) and complies with Bylaws requirements. Those who join the Texas RE can do so at no cost; put differently, there are no membership fees involved. Instead, Texas RE sources its funding from ERO funding, as well as from funding for state obligations.

ERO funding, derived from NERC, serves as the primary funding mechanism for Texas RE. More specifically, the funding is obtained from NERC Assessments and Penalty Sanction fees. NERC sources said funding by "*[allocating] costs to end users in the United States based on net energy for load*." Based on the national aggregate net energy load in 2015, NERC indicated that its proposed total United States net funding requirement for the ERO enterprise is $0.0000389 per kWh. For 2018 for instance, the ERO funding totals $11,548,986, comprised of $11,271,986 from NERC Assessments, $275,000 from Penalty Sanctions, and $2,000 in interest. This accounts for approximately 91% of the total budget for 2018.

Texas RE also utilizes ERCOT ISO system administration fees to fund state (non-statutory) activities. Non-statutory activities include auditing market participants' compliance with ERCOT Regional Rules, reporting on non-compliance, and providing testimony and regulatory support to the Public Utilities Commission of Texas ("PUCT"). The payment of said administration fee to Texas RE is authorized by the PUCT. For 2018, Texas RE's total non-statutory budget and funding is $1,091,743, accounting for approximately 9% of the total budget.

Sources: Texas RE. *2017 Annual Report*; Texas RE. *2019 Business Plan and Budget*; FERC. Docket No. RR16-6-000. *Order Accepting 2017 Business Plans and Budgets.* Issued October 20, 2016.

Similar to Texas RE, HRS Chapter 269-146 would enable utilities to collect a surcharge to recover "*appropriate and reasonable*" costs from all users of the Hawaiian electric system (i.e., ratepayers) in order to finance HERA's activities including the interconnection to the system, interconnection studies, and other analyses needed to assess the impact of infrastructure and operational systems on reliability.[16] As such, the surcharge would consequently increase ratepayers' monthly bills.

[15] "About Us." *Texas RE.* Web. September 18, 2018. <https://www.texasre.org/Pages/About-Us.aspx>

[16] HRS Chapter 269-146. *Hawaii electricity reliability surcharge; authorization; cost recovery.* HI Rev Stat § 269-146 (2017).

7 Hybrid model

Another model that the Project Team is analyzing is the so-called Hybrid model, which consists of Outcomes-based PBR with DSPP and IGO, to allow Hawaii to achieve most, if not all, of the State goals. At its core, this model would rely on the Outcomes-based PBR model discussed in Section 0. The functions of an independent system operator ("ISO") and independent distribution system operator ("DSO") will be combined to form the IGO. As such, responsibilities including planning and operations, including the dispatch of generation asset together with the operation of both the transmission and distribution systems, would fall under the purview of the IGO. Lastly, under this model, utilities would act as DSPPs. The DSPPs would then be able to establish the framework for grid support services for distributed energy resources ("DERs") and other service providers. Task 2.2.1 (Preliminary and high-level evaluation of the regulatory models relative to Hawaii State's goals) and Task 2.2.6 (Identification and recommendation for the three most beneficial regulatory models for further consideration) further discuss the details of this proposed hybrid model.

To assess how the costs of implementing this Hybrid model can be funded as a whole, the Project Team has examined how the implementation of each component of the regulatory model (i.e., Outcomes-based PBR, DSPP, and IGO) can be funded.

7.1 Outcomes-based PBR

Costs borne by the utilities under the Outcomes-based PBR component of the hybrid model would be funded and recovered in the same way as under a pure Outcomes-based PBR model. In other words, utilities would continue to fund its operating and capital spending through a combination of debt (short- and long-term) and equity and recovered through rate cases (see Section **Error! Reference source not found.** for further details).

7.2 DSPP

As has been mentioned in Task 2.2.1 and Task 2.2.3, there currently are no jurisdictions that have employed the DSPP model to completion. For a utility to take on the role of a DSPP, the utility would need to adopt certain grid platform infrastructure and technologies, thereby requiring a significant investment. The costs associated with said investments would be included in the utilities' revenue requirement and would ultimately be passed onto ratepayers in their monthly bills.

However, the DSPP model provides an additional revenue stream for utilities in addition to traditional revenues associated with the sale of electricity to end users. Platform Service Revenues ("PSRs") for utilities would be earned by the utilities for providing Distributed System Platform ("DSP") services to market participants as DSPPs. Examples of services may include customer origination via an online portal, data analysis, co-branding, transaction and/or platform access fees, optimization or scheduling services that add value to DER, advertising, energy services

financing, engineering services for microgrids, and enhanced power quality services.[17] As such, for the PSRs associated with implementing the DSPP model to be included in the rate case proceedings, ratemaking would need to be modified.

In this regard, New York's Reforming the Energy Vision ("REV") model provides a representative framework with regards to how utilities may achieve their earnings. More specifically, as per the State of New York Public Service Commission's ("NY PSC") *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework*, utilities have four ways of achieving earnings, as follows:[18]

1. traditional cost-of-service earnings;

2. earnings tied to achievement of alternatives that reduce utility capital spending and provide definitive consumer benefit;

3. earnings from market-facing platform activities; and

4. transitional outcome-based performance measures.

According to the NY PSC, "*these additional measures are collectively intended to create a regulatory environment where utilities can create shareholder value, comparable to or superior to conventional investments, by integrating third-party solutions and capital that improve the efficiency, resiliency, and flexibility of the physical networks, reduce consumer total costs[,] and achieve the State's policy objectives.*"[19]

In the context of the proposed Hybrid model for Hawaii, the Outcomes-Based PBR mechanism would accomplish the same objectives as the tracks 1, 2, and 4 as proposed by the NY PSC:

- With regards to the first track, even in a PBR environment, the traditional COS approach is used to calculate going-in rates which allow utilities to recover opex and capex financing costs.
- Under the second track, the PBR mechanism's total expenditure ("totex") approach ensures utilities' earnings would be tied to the achievement of alternatives that enable them to reduce capex all while providing a definitive consumer benefit.
- For the fourth and last track, Outcomes-based PBR is an effective implementation of a mechanism to ensure targets mandated by State policy goals are met through incentivizing the utility to achieve these outcomes, and where utilities' earnings would be linked with near-term measures that would enable customer savings as well as the

[17] State of New York Public Service Commission. *Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.* Order Adopting a Ratemaking and Utility Revenue Model Policy Framework. May 19, 2016. Page 41.

[18] Ibid, page 41.

[19] Ibid, page 2.

development of market-enabling tools.[20] In New York, for instance, this is achieved through the implementation of Earnings Adjustment Mechanisms ("EAMs") relating to peak reduction, energy efficiency, customer engagement, affordability, and interconnection.[21] However, the NY PSC's Order notes that "*over time, as PSRs become a larger component of utility revenues, the need for EAMs should diminish as utilities enable the success of markets in order to enhance their own earnings.*"[22]

The third track mentioned by the NY PSC in the REV proceeding is similar to the DSPP services envisioned in the proposed Hybrid model, where utilities would see earnings from market-facing platform activities. Increased PSRs would not only encourage utilities to allow DER providers access to their systems, but it would also aid in offsetting the required base revenues from ratepayers (i.e., the PSRs would be derived from ratepayers).[23]

The REV framework developed in New York has also enabled utilities to recover costs associated with pilot projects. One such example is Consolidated Edison's ("ConEd") Brooklyn-Queens Demand Management ("BQDM") project. Launched in 2014, the BQDM project consisted of a series of pilot programs that allowed ConEd to defer a $1.2 billion substation upgrade.[24] The NY PSC authorized ConEd to recover the costs of the approximately $200 million in investments, comprising of 52 MW of demand response investments and 17 MW of distributed resource investments, through a monthly supplemental charge on ratepayers' electric bills.[25,26] These increases on monthly electric bills are lower than those that would have allowed ConEd to recover substation upgrade costs.

7.3 IGO

As introduced in Task 2.2.1 (Preliminary and high-level evaluation of the regulatory models relative to Hawaii State's goals), the IGO represents the combined roles of the ISO and DSO. The IGO would be responsible for planning and operations, including transmission and distribution system dispatch, whereas the utilities would continue to own the transmission and distribution

[20] Ibid, page 12.

[21] Ibid, page 13.

[22] Ibid, page 13.

[23] Ibid, page 12 and page 50.

[24] "Straight Outta BQDM: Consolidated Edison looks to expand its non-wires approach." *Utility Dive.* July 19, 2017. Web. September 19, 2018. < https://www.utilitydive.com/news/straight-outta-bqdm-consolidated-edison-looks-to-expand-its-non-wires-appr/447433/>

[25] Ibid

[26] "A High-Wire Act: Balancing a Modern Grid with Regulated Assets." *Yale Center for Business and the Environment.* January 9, 2018. Web. September 19, 2018. <https://cbey.yale.edu/2018/01/09/high-wire-act-balancing-modern-grid-with-regulated-assets>

assets. Nonetheless, since the role of the proposed IGO for the State of Hawaii is akin to that of ISOs in other markets, the Project Team has turned to select ISOs as a reference for their funding mechanisms.

North American ISOs, such as ISO New England ("ISO-NE"), New York ISO ("NYISO"), PJM Interconnection ("PJM"), California ISO ("CAISO"), and Midcontinent ISO ("MISO"), as not-for-profit, non-taxed entities, fund the services they provide through private financing, as well as through fees collected from wholesale market participants (i.e., load-serving entities ("LSEs"), generators, marketers) that use regional transmission services. Similarly, an IGO could recover its costs through market participants that use both regional transmission and distribution services. While ISO costs are initially recovered through LSEs and generators, they do eventually trickle down to retail customers. Put differently, the ISO costs are added to generator offers, thereby increasing the cost of supply for LSEs; LSEs then add these increased costs to their revenue requirement, thereby once again translating to slightly higher rates for the end-consumer. To demonstrate funding mechanisms that can be used in the proposed IGO model, the Project Team has examined ISO-NE, NYISO, and PJM.

ISO New England

ISO-NE funds its opex and capex costs through a combination of private financing and market participant fees. While it does not have equity or accumulated reserves, ISO-NE has a $20 million line of credit with a bank, as well as an additional $4 million line of credit in case of shortages under the ISO New England Billing Policy. ISO-NE also has two private-placement issuances of approximately $50 million in total.[27] Apart from this, ISO-NE funds the remainder of its costs, namely administrative costs and capital costs to the extent not obtained through private financing, via the federally-regulated ISO New England Inc. Transmission, Markets, and Services Tariff ("ISO Tariff"). More specifically, the ISO Tariff is comprised of the Self-Funding Tariff (for the recovery of ISO-NE's administrative expenses) and the Capital Funding Arrangement tariffs (for the recovery of capital acquisition costs).[28,29] These costs are eventually translated to retail consumer costs in the form of a Basic Service charge; in 2018, for instance, ISO-NE services and benefits cost approximately $1.03 per month (for an average New England residential electricity customer with a usage of 750 kilowatt-hours per month). Further details ISO-NE's debt financing and ISO Tariffs can be found in Appendix B.

New York ISO

Like ISO-NE, NYISO employs both private financing and surcharges to market participants as a funding mechanism. In particular, NYISO has access to a $50 million revolving credit facility,

[27] ISO New England. *2017 Financial Report.* Page 6.
<https://www.iso-ne.com/static-assets/documents/2018/04/2017_financial_statements.pdf>

[28] ISO New England. *Transmission, Markets, and Services Tariff: Section IV.A Recovery of ISO Administrative Expenses.* January 1, 2017.
<https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_4/section_iva.pdf>

[29] ISO New England. *Transmission, Markets, and Services Tariff: Section IV.B Capital Funding Arrangements.* January 1, 2014. <https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_4/section_ivb.pdf>

valid through to December 31, 2018, to fund working capital expenses.[30] The ISO also has an unsecured $125 million line of credit, also valid through to December 31, 2018, to be used for the funding of capital purchases and project development.[31] Lastly, for the replacement of the ISO's Energy Management and Business Management Systems, NYISO entered into an unsecured $30 million delayed-draw term loan in March 2016; funds can be drawn until December 31, 2018. NYISO also funds opex, additional capital requirements, and debt service costs through a surcharge imposed on NYISO market participants (i.e., Rate Schedule 1). Like ISO-NE, as well, these charges do eventually trickle down to retail customer bills but account for a small portion as part of supply charges.[32] Further details on NYISO's funding mechanisms can be found in Appendix B.

PJM Interconnection

Like the abovementioned ISOs, PJM, too, incurs short- and long-term debt to pay for its capital expenses. PJM has a $100 million revolving credit agreement with PNC bank through to March 23, 2021. As of March 1, 2018, the unsecured promissory note increased to $150 million. In terms of long-term debt, PJM has a $26.3 million loan agreement with maturity through to September 1, 2021. PJM also obtains liquid collateral from transmission customers for funding transmission system modifications; as of December 31, 2017, these amounted to approximately $94.3 million.[33] Administrative costs, on the other hand, are recovered through LSEs and generators through the Open Access Transmission Tariff ("OATT"); more specifically, PJM's cost recovery structure is comprised of the following services under OATT: Control Area Administration Service; Financial Transmission Rights Administration Service; Market Support Service; Regulation and Frequency Response Administration Service; and Capacity Resource and Obligation Management Service. Like most ISOs, the charges appear as a service charge on end-consumers' monthly bills. In the event costs are over-recovered, PJM refunds the overcollection to the market participants in the preceding quarter. In the event fees are under-recovered, PJM may utilize its approximately $14 million long-term financial reserves, previously funded by PJM members.[34] Further details about the funding mechanisms PJM utilizes can be found in Appendix B.

[30] NYISO. *Financial Statements December 31, 2017 and 2016 (With Independent Auditors' Report Thereon)*. Page 14.

[31] Ibid, page 14.

[32] "Frequently Asked Questions." *NYISO.* Web. September 11, 2018. <https://home.nyiso.com/faq/>

[33] Ibid.

[34] "How Does PJM Make Money?" *PJM.* Web. September 19, 2018. < https://learn.pjm.com/who-is-pjm/how-does-pjm-make-money.aspx>

8 Appendix A: Scope of work to which this deliverable responds

2.5.5 Identification of funding mechanisms for each regulatory model. CONTRACTOR shall identify potential funding mechanisms of each regulatory model, including an overview of the direct and indirect cost to customers for each model.

DELIVERABLE FOR TASK 2.5.5. CONTRACTOR shall provide its conclusions and all work related to identifying funding mechanisms for each regulatory model. CONTRACTOR shall include discussions of various funding mechanisms, such as utility rates and surcharges on those rates, capital markets, potential taxes, system benefit charge, property tax, accessing capital markets. CONTRACTOR shall provide a written summary of the findings in MS Word and Power Point. CONTRACTOR shall submit deliverable for TASK 2.5.5 to the STATE for approval.

9 Appendix B: ISO funding mechanisms

9.1 ISO New England

ISO-NE funds its opex and capex through a combination of private financing and market participants. With regards to private financing, ISO-NE has neither equity nor accumulated reserves. The ISO Tariff allows the recovery of costs, including costs of debt service, and dictates the creditworthiness of the ISO. In terms of the ISO's capital requirements, ISO-NE has a $20 million line of credit provided by a bank, as well as a $4 million line of credit with a bank in the case ISO-NE is short of funding under the ISO New England Billing Policy.

Further, "*Capital Funding Arrangements of the ISO tariff is the backstop to all the ISO's borrowings in the event of any acceleration of debt repayments*" (discussed in greater detail below).[35] ISO-NE currently also has "*two private-placement, fixed-rate note issuances totaling $50 million.*"[36]

Moreover, ISO-NE funds its administrative and the remainder of its capital costs (to the extent not obtained by the ISO through private financing) through market participants (i.e., the buyers and sellers in the wholesale electricity market), through which the effects eventually trickle down to the consumers of electricity. As such, most costs (except a few) are incurred indirectly by the customers. As a not-for-profit entity, service rates are set at levels such that ISO-NE is able to recover only what it needs to operate, determined annually through their budgeting process (Figure 3).[37]

As part of their budgeting process, or Step 2, ISO-NE develops an operating budget as well as a capital budget. The operating costs include "*the administrative functions of the ISO, including costs for scheduling and administering the movement of power through, out of, or within the balancing authority area; and costs for services the ISO provides to administer the energy and reliability markets*."[38] The capital budget, on the other hand, covers the cost of capital projects.

Since ISO-NE is a not-for-profit organization, the ISO "*charges a small fee to buyers and sellers in the wholesale markets for each transaction that the ISO handles on their behalf.*"[39] To determine what the fee will be, ISO-NE operates under a federally-regulated tariff, namely the ISO New England Inc. Transmission, Markets, and Services Tariff ("ISO Tariff"). The ISO Tariff is a FERC approved a document that governs "*the rates, terms, and conditions for the transmission, market, and other services*

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[35] ISO New England. *2017 Financial Report.* Page 6. <https://www.iso-ne.com/static-assets/documents/2018/04/2017_financial_statements.pdf>

[36] Ibid, page 5.

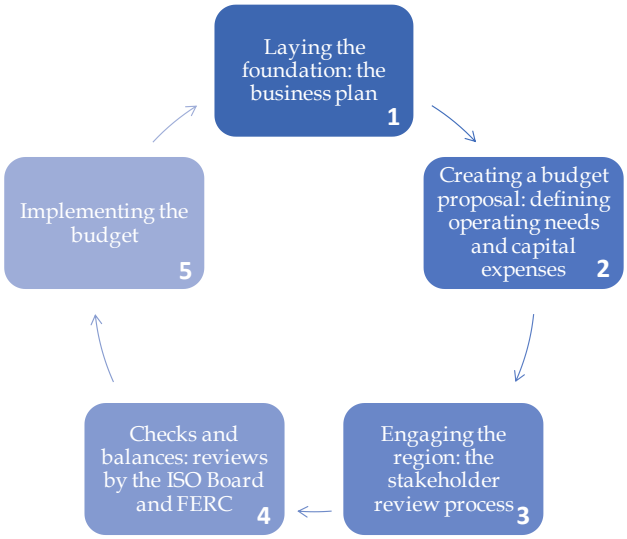
[37] "The ISO's Funding and Budgeting Process." *ISO New England.* Web. August 24, 2018. <https://www.iso-ne.com/about/what-we-do/in-depth/the-iso-funding-and-budgeting-process>

[38] "Transmission, Markets, and Services Tariff." *ISO New England.* Web. August 24, 2018. <https://www.iso-ne.com/participate/rules-procedures/tariff>

[39] "Wholesale vs. Retail Electricity Costs." *ISO New England.* Web. August 24, 2018. <https://www.iso-ne.com/about/what-we-do/in-depth/wholesale-vs-retail-electricity-costs>

ISO New England provides."[40] In particular, Section IV of the ISO Tariff discusses the various "*funding mechanisms and capital funding arrangements*" ISO-NE utilities in order to administer how the ISO acquires its funding.

Figure 3. ISO-NE's funding and budgeting process



Source: ISO New England

Self-Funding Tariff

The Self-Funding Tariff[41], or the recovery of ISO-NE's administrative expenses, describes the means by which ISO-NE recovers the costs to fulfill its administrative duties in each calendar year. These functions carried out by the ISO are comprised of:

- Scheduling, System Control, and Dispatch Service ("Scheduling Service");
- Energy Administration Service ("EAS"); and
- Reliability Administration Service ("RAS").

The **Scheduling Service** is an ancillary service that only the ISO can provide and consists of the service associated with regional-level scheduling of the "*movement of power through, out of, within, or into the New England Control Area.*"[42] In that regard, all market participants using ISO-NE's

[40] "FAQs: The ISO Tariff and its Funding Mechanisms." *ISO New England.* Web. August 24, 2018. <https://www.iso-ne.com/participate/support/faq/oatt-iso-tariff#a>

[41] ISO New England. *Transmission, Markets, and Services Tariff: Section IV.A Recovery of ISO Administrative Expenses.* January 1, 2017. <https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_4/section_iva.pdf>

[42] Ibid, page 10.

transmission service are customers of the ISO's Scheduling Service, thereby purchasing this service from the ISO. Costs are based on the activities required to provide the Scheduling Service, and thereby include (but are not limited to): the processing and implementation of regional transmission service requests, the coordination of the transmission system operations and the implementation of control actions to support said functions, billing associated with regional transmission services provided under the Tariff, transmission system planning activities to support the Scheduling Service, and associated administrative costs.[43]

Furthermore, **EAS** is the service provided by ISO-NE to administer the energy market. As such, expenses include (but are not limited to) those associated with: core operations; generation and demand dispatch associated with energy markets; energy accounting; loss determination and allocation; billing preparation; market power monitoring and mitigation; sanctions activities; operation of FTR auctions; market assessment and reports; and formulation of market rules and proposals to modify rules.[44]

Lastly, **RAS** is the service provided by ISO-NE to administer the reliability markets, "*facilitate reliability-associated transactions and arrangements*," and to provide "*reliability and informational services*."[45] RAS administrative costs include (but are not limited to) generation and demand dispatch associated with reliability markets; reliability markets accounting; billing preparation; generation emissions analysis; risk profile updates; triennial review of resource adequacy; studies and qualification of resources under the Forward Capacity Market; preparation of regional reports and load forecasts and profiles; power supply, environmental, and market reliability planning activities support; monitoring, mitigation, and assessment of market power for reliability markets; and the formulation of market rules and proposals to modify rules.[46]

Capital Funding Arrangements Tariff

The Capital Funding Arrangements Tariff, on the other hand, is utilized for ISO-NE to collect the following: [47]

1. "*the revenues necessary, to the extent not obtained by the ISO through private financing, for the acquisition of capital assets required for support of the ISO's operations;*

2. *any remaining unamortized costs of capital items financed by the ISO in the event of termination, acceleration[,] or other required repayment of private financing approved by the Commission…;*

[43] Ibid, page 10.

[44] Ibid, page 12.

[45] Ibid, page 15.

[46] Ibid, page 15.

[47] ISO New England. *Transmission, Markets, and Services Tariff: Section IV.B Capital Funding Arrangements.* January 1, 2014. <https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_4/section_ivb.pdf>

3. *the working capital amount required by the ISO in the event of termination, acceleration[,] or required repayment of private financing approved by the Commission…; and*

4. *amounts owed by the ISO in the event of termination, acceleration[,] or required repayment of Shortfall Funding Arrangement financing approved by the Commission…"*

Therefore, there are four categories of costs that comprise the Capital Funding Arrangements Tariff, namely the Capital Funding Chart ("CFC"), the Early Amortization Charge ("EAC"), the Early Amortization Working Capital Charge ("EAWCC"), and the Early Payment Shortfall Funding Charge ("EPSFC").

The **CFC** recovers the costs associated with the acquisition of capital items that have not been funded by private financing or other sources of funding. Funds are collected from Market Participant funds for the direct purchase of said capital assets, and the cost of each capital item is allocated between the three services (i.e., Scheduling Service, EAS, and RAS) depending on the extent to which the capital item is used in providing each service. The CFC is billed on a monthly basis.

The **EAC** collects from the Market Participants "*remaining unamortized costs of capital items financed by the ISO in the event of termination, acceleration[,] or required repayment of private financing, or in the case of non-amortizing private financing, payment at maturity if the ISO is unable to refinance such non-amortizing private financing.*"[48] ISO-NE provides notice to each Market Participant electronically at least 30 business days prior to when the payment is due to its lenders.

The **EAWCC** is billed to and paid by the Market Participant for funds that are needed to "*fund the working capital amount in the event of termination, acceleration[,] or required repayment of private refinancing entered into by the ISO…in support of its working capital needs*."[49] As in the case of the EAC, ISO-NE provides notice of the "*aggregate amount of working capital (the "EAWW Amount")"* to each Market Participant electronically at least 30 business days before when the payment is due to its lenders.

Lastly, the **EPSFC** will collect funds that are required to be paid by the ISO "*in the event of termination, acceleration[,] or required repayment of the Shortfall Funding Arrangement financing entered into by the ISO in support of weekly billing under the ISO New England Billing Policy.*"[50] Also in the case of the EPSFC, ISO-NE provides notice of at least 30 business days before the payment is due to its lenders.

ISO-NE costs on the retail bill

In the end, the wholesale market cost incurred by the load server or supplier as described through the ISO Tariff above is reflected in the end-consumers bill as part of the "Basic Service" or

[48] Ibid, page 3-4.

[49] Ibid, page 4.

[50] Ibid, page 4.

"Default Service" in cents/kilowatt hour.[51] Under this charge, wholesale market energy and reliability costs are packaged with other costs from the supplier. As an example, based on a usage of 750 kilowatt-hours per month for the average New England residential electricity customer in 2018, ISO-NE services and benefits cost an average of $1.03 per month.[52]

9.2 New York ISO

Like ISO-NE, NYISO uses a combination of private financing and surcharges to market participants to fund its operations. With regards to private financing, NYISO can incur debt to pay for capital expenses, as required. NYISO has access to a $50 million revolving credit facility with an effective date of December 31, 2018, to fund its working capital expenses.[53] In 2017, NYISO had borrowings amounting to approximately $6 million under the credit agreement at an average interest rate of 2.067%; as of December 31, 2017, there were no outstanding amounts on said credit facility.[54]

In terms of long-term debt, on March 18, 2016, "*NYISO amended and restated its unsecured [$100] million line of credit facility to increase the unsecured amount to [$125] million and allow the proceeds to be drawn through December 31, 2018*."[55] Borrowings from this line of credit were used for capital purchases and development of projects. Also, NYISO entered into another unsecured $30 million delayed-draw term loan on March 18, 2016, for the replacement of the ISO's Energy Management and Business Management Systems; the proceeds can be used through to December 31, 2018.[56]

NYISO also funds its operating expenses, capital requirements, and debt service costs based on a "*strict beneficiary pays principle.*"[57] Put differently, the expenses incurred by NYISO are paid through a surcharge (i.e., Rate Schedule 1) that is paid by market participants in New York's wholesale electricity markets; these costs eventually trickle down to the consumer but account for a tiny fraction of monthly electricity bills as part of supply charges.[58]

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[51] "Wholesale vs. Retail Electricity Costs." *ISO New England.* Web. September 10, 2018. <https://www.iso-ne.com/about/what-we-do/in-depth/wholesale-vs-retail-electricity-costs>

[52] "The ISO's Funding and Budgeting Process." *ISO New England.* Web. September 10, 2018. <https://www.iso-ne.com/about/what-we-do/in-depth/the-iso-funding-and-budgeting-process>

[53] NYISO. *Financial Statements December 31, 2017 and 2016 (With Independent Auditors' Report Thereon)*. Page 14.

[54] Ibid, page 14.

[55] Ibid, page 14.

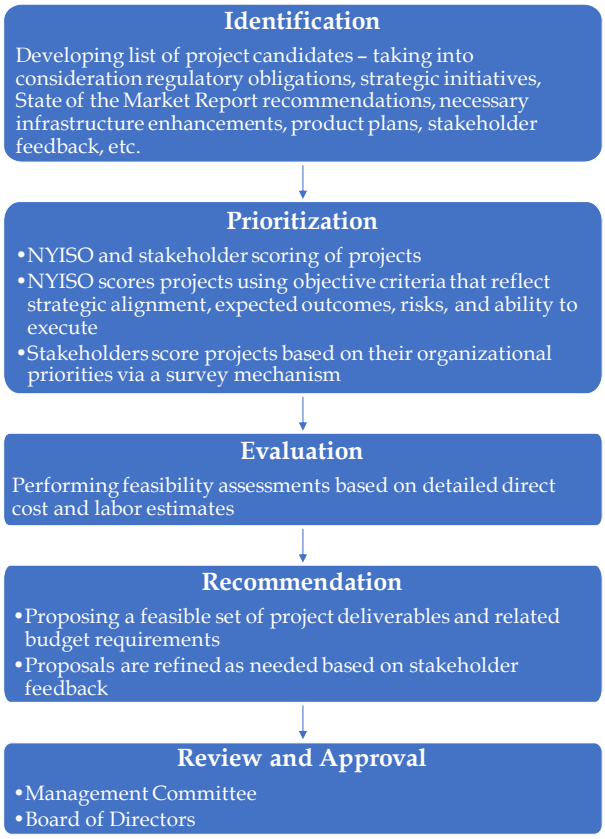
[56] Ibid, page 15.

[57] NREL. *A Survey of Transmission Cost Allocation Methodologies for Regional Transmission Organizations.* February 2011. <https://www.nrel.gov/docs/fy11osti/49880.pdf>

[58] "Frequently Asked Questions." *NYISO.* Web. September 11, 2018. <https://home.nyiso.com/faq/>

The amount to be recovered is determined through the NYISO budget process. The Budget and Priorities Working Group projects funding in four phases (i.e., identification, prioritization, evaluation, and recommendation), as depicted in **Error! Reference source not found.**Figure 4.[59]

Figure 4. NYISO's funding and budgeting process



Source: "NYISO Budget." *NYISO.* Web. September 11, 2018. <http://www.nyiso.com/public/markets_operations/services/financial_services/budget/index.jsp>

As of July 1, 2018, the two FERC-approved NYISO tariffs, namely the **Open Access Transmission Tariff ("OATT")** and the **Market Administration and Control Area Services Tariff ("Services Tariff")** were "*amended to clarify NYISO's role as the single counterparty to market participant transactions in the NYISO markets.*"[60] The Services Tariff establishes the requirements applicable to NYISO's administrative functions, namely the administration of competitive markets for energy and capacity transactions, as well as the payments for suppliers of ancillary services in the

[59] "NYISO Budget." *NYISO.* Web. September 11, 2018. <http://www.nyiso.com/public/markets_operations/services/financial_services/budget/index.jsp>

[60] NYISO. *Independent Auditors' Report.* 2016 Financial Statements. Page 21. <https://www.nyiso.com/public/webdocs/markets_operations/services/financial_services/Budget/Financial_Statements/2016-Annual-Financials.pdf>

administered markets and the provision of Control Area Services. This includes NYISO's services in ensuring the reliability of the power system. On the other hand, OATT sets forth the requirements for NYISO's transmission services.

Collectively known as the ISO Tariffs, these NYISO tariffs allow the ISO to recover its capital requirements, operating expenses, and debt service costs through a surcharge, Rate Schedule 1, to market participants.[61,62] NYISO earns revenues from Rate Schedule 1 once energy is scheduled and dispatched; market participants then settle said charges in the following settlement period.[63]

Rate Schedule 1

Under Rate Schedule 1, NYSIO bills each transmission customer[64] during each billing period to recover its budget costs, as well as certain other non-budged costs (e.g., NERC and Northeast Power Coordinating Council charges on a quarterly basis and FERC charges on a billing period-basis). ISO annual budgeted costs to be recovered are those associated with NYISO's operations of the transmission system as well as with the administration of the ISO Tariffs and ISO Related Agreements, including costs related to (but not limited to) the following:[65]

- Transmission system operations, administration, and support costs;
- Processing and implementation requests for transmission services (including OASIS support);
- Administration and operation of the LBMP market and other markets administered by NYISO;
- Administration of Control Area Services, Market Power Mitigation Measures, and Market Monitoring Plan;

[61] Ibid, page 21.

[62] NYISO's share of FERC fees are recovered through an independent mechanism effective January 1, 2016. Market participants are invoiced FERC fees on a monthly basis based on estimated annual fees; once NYISO receives the actual annual amount, NYISO recovers the true-up amount "*equal to the difference between the estimated fee and the actual fee.*" (Source: NYISO. *Independent Auditors' Report.* 2016 Financial Statements. Page 21. <https://www.nyiso.com/public/webdocs/markets_operations/services/financial_services/Budget/Financial_Statements/2016-Annual-Financials.pdf>)

[63] Ibid, page 21.

[64] A transmission customer is any entity that requests or receives transmission services pursuant to a Service Agreement and the terms of the ISO OATT. Market participants include transmission customers. (Source: NYISO. *NYISO MST.* Web. September 11, 2018. Page 80. <https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf>)

[65] NYISO. *NYISO OATT, 6.1-6.1.8 OATT Schedule 1- ISO Annual Budget Charge.* Web. September 11, 2018. <http://www.nyiso.com/public/markets_operations/documents/tariffviewer/index.jsp>

- Reliability maintenance;
- Provision of transmission services;
- Settlement statement preparation;
- Engineering services and operations planning;
- Regulatory fees;
- Carrying costs on ISO assets, capital requirements, and debts; and
- Administrative and general expenses.

However, that "*[transmission customers] who are retail access customers being served by [an LSE] shall not pay these charges to [NYISO]; the LSE shall pay these charges.*"[66] With the amounts collected under Rate Schedule 1, NYISO has formed a working capital reserve to maintain NYISO market stability. As such, "*any [changes] to NYISO's working capital needs would be billed to market participants in future Rate Schedule 1 charges.*"[67]

9.3 PJM Interconnection

PJM Interconnection and PJM Settlement (i.e., the subsidiary of PJM responsible for member billing) are regulated by FERC. As non-stock companies, neither PJM Interconnection nor PJM Settlement can raise equity funding through stock shares; both companies also do not have any publicly issued or traded debt (e.g., bonds), but are able to incur short- and long-term debt for the recovery of capital expenses.[68] PJM administrative expenditures, on the other hand, are recovered through its members through fixed rates in PJM's OATT.

Capital expenses

PJM Interconnection is able to incur short-term and long-term debt to pay for its capital expenses. Nonetheless, if PJM's actual expenses are projected to be greater than PJM's revenues and financial reserves, PJM would need to recover costs through a rate case with FERC.

While it does not have any publicly issued or traded debt, PJM had a $100 million revolving credit agreement with PNC Bank which expired on March 23, 2018 but was granted an extension through to March 23, 2021. On November 17, 2017, PJM filed a request to extend the facility and to increase the current unsecured promissory note to $150 million. The request was approved on

[66] Ibid.

[67] NYISO. *2016 Annual Report.*

[68] "How Does PJM Make Money?" *PJM.* Web. September 19, 2018. <https://learn.pjm.com/who-is-pjm/how-does-pjm-make-money.aspx>

January 19, 2018, and the credit facility increase took effect with PNC on March 1, 2018. The "*[credit] facility is unsecured and is available to fund short-term cash obligations.*"[69] However, as of December 31, 2017, "*there were no outstanding borrowings under the revolving credit agreement.*"[70]

With regards to long-term debt, PJM's $35 million loan agreement was approved by FERC in 2009. In 2013 however, this loan was amended and refinanced at a lower interest rate for $26.3 million with the maturity extended from April 30, 2015, to September 1, 2021. As of December 31, 2017, outstanding borrowings amounted to approximately $20.7 million.[71]

In terms of costs of transmission system modifications, PJM obtains liquid collateral from transmission customers; as of December 31, 2017, PJM held deposits for study and interconnection activities amounting to approximately $94.3 million.[72]

Administrative expenses

Depending on members' activities, the administrative costs recovered via the OATT include, but are not limited to, the costs of operating the transmission system and wholesale electricity markets. Members/users include LSEs, generators, and others; approximately 75% of its costs are recovered from LSEs, whereas the remaining 25% are recovered from generation owners (20%) and financial marketers/traders (5%).[73]

More specifically, PJM's administrative cost recovery structure is comprised of the rates specified in OATT Schedules 9-1 to 9-5, comprising of tariffs for the following services:[74]

1. **Control Area Administration Service** includes activities pertaining to maintenance of reliability, as well as the administration of the Point-to-Point Transmission Service and Network Integration Transmission Service. As such, PJM charges users of this service depending on the MWh of energy delivered (including losses) by the member on a monthly basis.

2. **Financial Transmission Rights Administration Service** includes PJM activities related to the administration of Financial Transmission Rights ("FTRs"), including FTR bilateral

[69] *PJM.* PJM 2017 Financial Report.

[70] Ibid.

[71] Ibid.

[72] Ibid.

[73] Ibid.

[74] PJM. *PJM Open Access Transmission Tariff.* September 17, 2010. <https://www.pjm.com/directory/merged-tariffs/oatt.pdf>

trading, FTR auctions, PJM's online FTR reporting tool, and FTR analyses. PJM charges users Component 1 of the FTR Service Rate based on the total FTRs in MWh in a month, and Component 2 based on the sum of the "*number of hours in all bids to buy [FTRs] Obligations*" and "*five times the number of hours in all bids to buy [FTRs] Options*" in each month.[75] Component 1 applies to any bid submitted in the monthly, annual, or long-term FTR auction, whereas Component 2 applies to any bid submitted in the annual FTR auction and the applicable monthly FTR auction, as well.

3. **Market Support ("MS") Service** includes PJM activities related to operations of the PJM Interchange Energy Market and its relevant functions, such as "*market modeling and scheduling functions, locational marginal pricing support, and support of PJM's [Internet-based] customer transaction tools*."[76] Users of the Market Support Service are charged on a monthly basis. The charge is comprised of Component 1 of the MS Service rate, based on the total MWhs of energy delivered to load in the PJM region, the total MWhs of energy input into the transmission system by a Generation Provider, and the total MWHs of all accepted Increment Offers, Decrement Bids, and "Up-to" Congestion Transactions. Component 2 of the MS Service Rate is charged based on the number of Bid/Offer Segments submitted by each user each month.

4. **Regulation and Frequency Response Administration Service** includes activities pertaining to the administration of the Regulation, and Frequency Response Service provided to LSEs and generators. Users of said service are charged the rate on a monthly basis based on the MWhs of the user's hourly regulation objective as an LSE, as well as the MWhs of regulation scheduled from generating units.

5. **Capacity Resource and Obligation Management Service** includes activities associated with "*assuring that customers have arranged for sufficient generating capacity to meet their unforced capacity obligations under the Reliability Assurance Agreement[("RAA"),]…processing Network Integration Transmission Service*", administering the Reliability Pricing Model auctions, and administering of the RAA.[77] This service is provided to LSEs and owners of capacity resources.[78] PJM charges each LSE on a monthly basis the Capacity Resource and Obligation Management Rate based on the LSE's MW per day of the daily unforced capacity obligation; in addition to this charge, PJM also charges each entity that includes in its Fixed Resource Requirement Capacity Plan a Capacity Resource committed to serving load a Capacity Resource and Obligation Management Rate charge based on the

[75] Ibid.

[76] Ibid.

[77] Ibid.

[78] Ibid.

entity's share in MWs of unforced capacity of all capacity resources committed to serve load for the month.

If PJM over-collects said fees in relation to its actual expenditures for each quarter, PJM refunds these amounts to members in the quarter to follow. Conversely, if PJM collects fewer fees than needed to cover its actual expenditures, then PJM can utilize its long-term financial reserve of approximately $14 million, previously funded by PJM members.[79]

[79] "How Does PJM Make Money?" *PJM.* Web. September 19, 2018. < https://learn.pjm.com/who-is-pjm/how-does-pjm-make-money.aspx>

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A high-level assessment of whether benefits of ownership and regulatory model changes can be accomplished through changes in rate design

working paper prepared by London Economics International LLC for the State of Hawaii with support from Meister Consultants Group

April 12, 2019

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This document, which corresponds to Tasks 3.1.1 and 3.1.2 of the scope of work, is one of several working papers associated with that engagement. It provides a high-level qualitative assessment of whether the benefits of ownership and regulatory model changes can be achieved through changes to Hawaii's existing rate design. The Project Team evaluated a range of alternative rate designs including tiered rates (inclining and declining block rates), higher fixed charges, and time-varying rates (Time-of-Use ("TOU") rates, Real-Time Pricing ("RTP"), Critical Peak Pricing ("CPP")). Based on a high-level qualitative evaluation of these alternative rate designs, the Project Team concluded that rate design changes can be effective complementary mechanisms to ownership and regulatory changes and could help achieve some of Hawaii's state energy goals such as increasing the adoption of DERs and other consumer side resources, lowering peak demand, and encouraging energy conservation. At the same time, rate design is inherently interlinked with ownership and regulatory models and care must be taken to ensure that changes to rate design are consistent with overall policy goals in light of the prevailing ownership and regulatory model.

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List of acronyms

COS	Cost-of-Service
CPP	Critical Peak Pricing
DBEDT	Hawaii Department of Business, Economic Development, and Tourism
DER	Distributed Energy Resource
DSPP	Distributed System Platform Provider
FERC	Federal Energy Regulatory Commission
HECO	Hawaiian Electric Company
HEI	Hawaiian Electric Industries
HELCO	Hawaii Electric Light Company
HERA	Hawaii Electricity Reliability Administrator
IOU	Investment Owned Utility
IPP	Independent Power Producer
IGO	Integrated Grid Operator
ISO	Independent System Operator
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International, LLC
MCG	Meister Consultants Group
MECO	Maui Electric Company
PBR	Performance-Based Regulation
PUC	Public Utilities Commission
RTP	Real-Time Pricing
SB	Single Buyer
TOU	Time-of-Use

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1 Executive summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which responds to Tasks 3.1.1 and 3.1.2 in the project scope of work, provides a high-level qualitative assessment of whether the benefits of ownership and regulatory model changes can be achieved through changes in rate design. The Project Team evaluates a range of alternative rate designs including:

- Tiered rates;
  - Inclining block rates; and
  - Declining block rates
- Higher fixed charges; and
- Time-Varying Rates;
  - Time-of-Use ("TOU") Rates;
  - Real-Time Pricing ("RTP"); and
  - Critical Peak Pricing ("CPP")

Following a high-level qualitative evaluation of these rate designs, including associated advantages and disadvantages, the Project team evaluated the economic and regulatory benefits of these rate designs compared to that of ownership and regulatory model changes. Specifically, the Project team qualitatively assessed the relative ability of these rate designs to:

1. maximize consumer savings (including the maximum possible impact in percentage terms that these rate designs might have on savings based on previous experience in other markets);
2. enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs;
3. eliminate or reduce conflicts of interest in energy resource planning, delivery and regulation; and
4. align management, ownership, and ratepayer interests.

Based on this high-level qualitative assessment, the Project Team concluded that rate design changes can be effective complementary mechanisms to ownership and regulatory changes and could help achieve some of Hawaii's state energy goals such as increasing the adoption of DERs and other consumer side resources, lowering peak demand, and encouraging energy conservation. Furthermore, depending on overarching ownership or regulatory model changes, rate design changes can contribute to increasing consumer savings and, to an extent, aligning utility and consumer incentives.

However, it is important to note that rate design is interlinked with prevailing regulatory and ownership models and can help advance or undermine state policy goals. As such, policymakers and regulators must be mindful of state policy objectives and the broader ownership and regulatory context when considering changes to rate design. Indeed, given the broad array of initiatives underway in Hawaii, a quantitative analysis of any potential rate design changes may be warranted once those initiatives have been implemented.

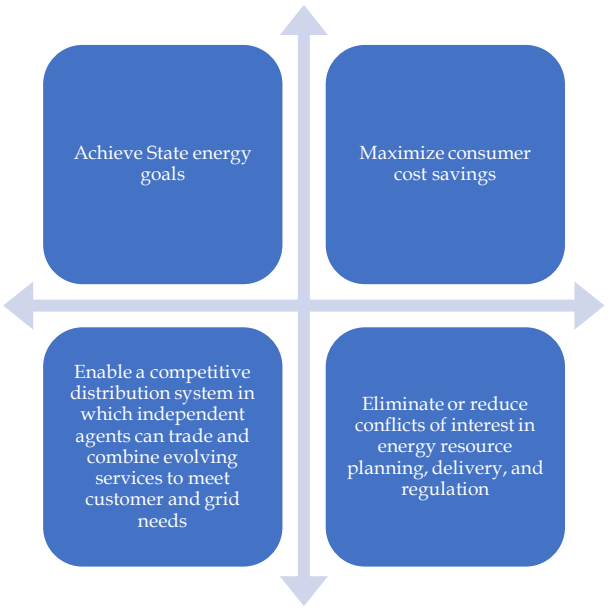
2 Introduction and scope

2.1 Project description

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the State legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[1] was contracted to perform this study.[2]

The goal of the project is to evaluate the ability of each model to achieve the State's key criteria[3] listed in Figure 1.

Figure 1. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

The study will help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the State. In addition, it will also aid in identifying the process to be followed to implement such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy

[1] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[2] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[3] House Bill No. 1700 Relating to the State Budget.

resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[4]

2.2 Role of this deliverable relative to others in the project

This deliverable responds to Tasks 3.1.1 and 3.1.2 in the project scope of work. It provides a high-level qualitative assessment of whether the benefits of recommended ownership and regulatory model changes (noted in Tasks 1.2.4 and 2.2.6) could be achieved through changes to Hawaii's existing rate design.

In response to Task 3.1.1., it qualitatively assesses the extent benefits of ownership and regulatory model changes, including the alignment of utility interests with State policy, could be accomplished through changes in rate design. In doing so, it evaluates a range of alternative rate designs and the benefits they might offer the Hawaii electric power system relative to changes to the ownership and regulatory model.

In response to Task 3.1.2, it explicitly assesses how the proposed rate design changes compare to regulatory, and ownership model changes in terms of their ability to:

(a) maximize consumer savings;

(b) enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs;

(c) eliminate or reduce conflicts of interest in energy resource planning, delivery and regulation; and

(d) align management, ownership, and ratepayer interests.

Furthermore, the Project Team provides data on the possible impact in percentage terms that some of the alternative rate designs might have on savings based on previous experience.[5]

[4] Hawaii Contract No. 65595. Scope of Services.

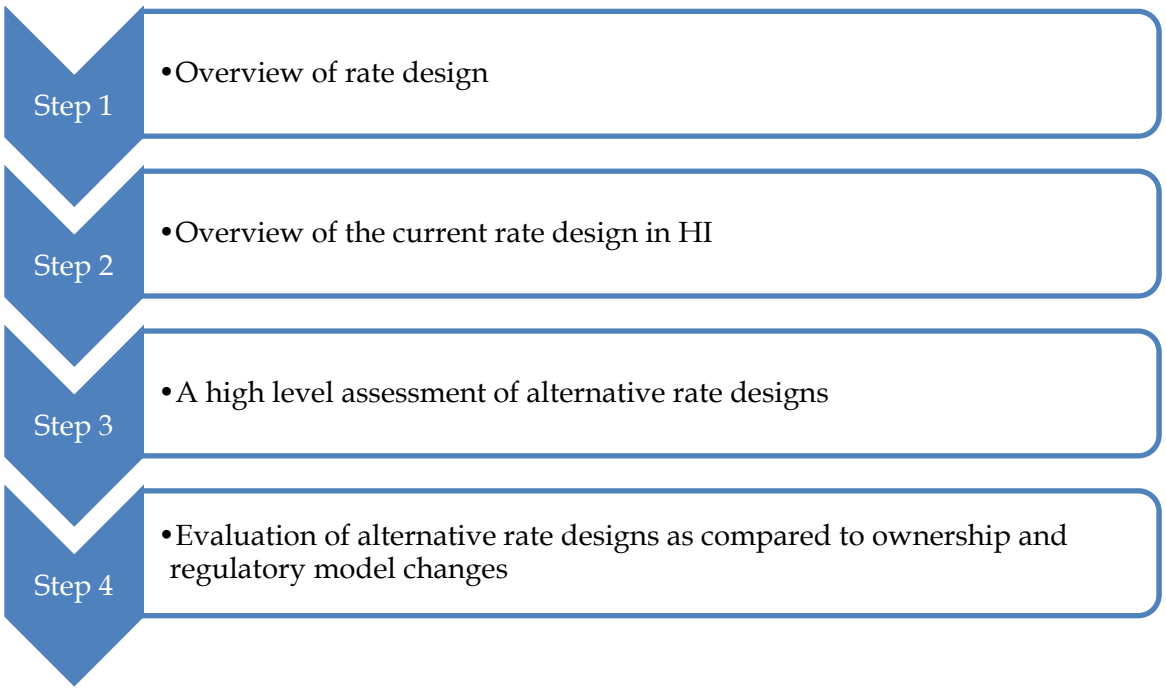
[5] Please note that the data included only represents alternative rate design for which pilot projects have been conducted and energy savings data exists.

3 Methodology

The Project Team followed a series of four steps to assess the benefits of rate design changes relative to that of ownership and regulatory model changes and evaluate their ability to achieve Hawaii's energy goals.

First, the Project Team laid out an explanation of how traditional rate design is usually implemented in the United States and Hawaii. Next, the Project Team discussed the details of the current rate design in Hawaii. Then, the Project Team evaluated a range of alternative rate designs including tiered rates (inclining and declining block rates), higher fixed charges, and time-varying rates (Time-of-Use ("TOU") rates, Real-Time Pricing ("RTP"), and Critical Peak Pricing ("CPP")). Finally, the Project Team qualitatively compared the benefits of these rate designs with the benefits of ownership and regulatory model changes proposed in prior tasks.

Figure 2. Summary of methodology for evaluating rate design changes

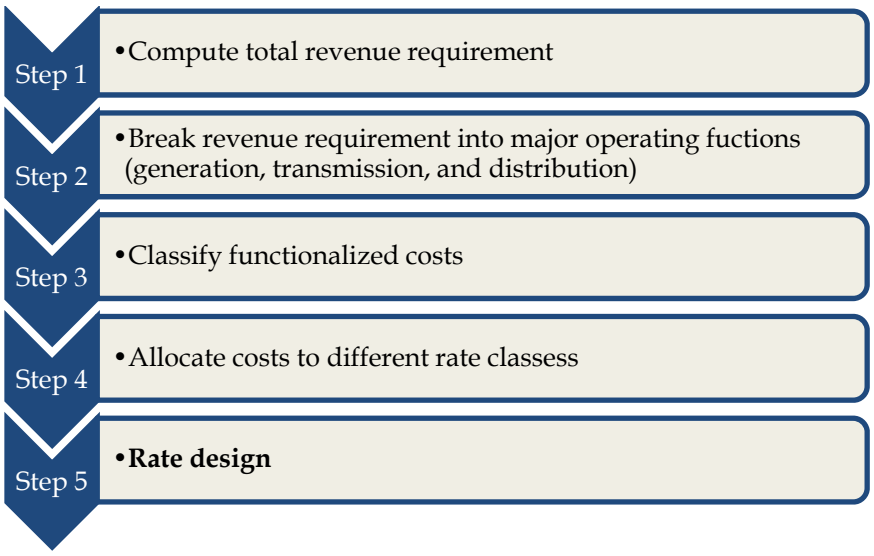


4 Overview of rate design

Rate design refers to the itemized pricing structure reflected in consumers' monthly electric bills including the underlying mechanism used to derive the prices.[6] As discussed in the other working papers, rate design starts with calculating the total annual revenue requirement of a utility. In many jurisdictions, this is usually based on a Cost-of-Service ("COS") approach, though this can vary in jurisdictions that have performance-based ratemaking.[7] The revenue requirement covers all expenses incurred by the utility and a fair return on its investments. Following that step, the cost components are allocated to different customer classes.

Rate design is the final step in the rate design process following the allocation of costs to different customer classes including residential, commercial, industrial, and others. Figure 3 below shows the series of steps involved in the rate design process.[8]

Figure 3. Key steps in rate design methodology



Rates are typically designed by state regulators and vary across jurisdictions and customer classes. Traditional rate designs consist of two-parts including a fixed charge ($ per month) and a per unit energy charge applied to the amount of electricity consumed ($/kWh). The fixed charge accounts for costs incurred by the utility that are independent of electricity usage. On the other

[6] Lazar, Jim, and Wilson Gonzalez. "Smart Rate Design for a Smart Future." RAP, July 2015, http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-gonzalez-smart-rate-design-july2015.pdf.

[7] The Hawaii Public Utility Commission is currently leading a proceeding on investigating Performance Based Regulation (Docket No. 2018-0088).

[8] Please refer to the deliverable for Task 1.6.4 on retail rates for an in-depth explanation of the first 4 steps of the cost service mechanism and how it is used by HECO and KIUC companies

hand, the energy charge accounts for the costs incurred to generate and distribute electricity to consumers. The energy charge (in $/kWh) is calculated by dividing the total cost allocated to a given customer class by the total kilowatt-hour sales for that class.

Residential consumers typically have a monthly fixed charge and an energy charge. On the other hand, commercial and industrial consumers usually have a three-part rate which also includes a demand charge in addition to a fixed charge and energy charge. Accordingly, the monthly rate reflected on monthly commercial bills typically consists of the following types of charges:

1. **Fixed charge ($ per customer) –** used to recover costs related to billing and metering; outside of the generation and delivery of electricity. This applies to all customer classes regardless of usage levels. In certain cases, utilities use fixed charges to recover distribution system costs.[9]

2. **Energy charge ($ per kWh) –** accounts for the cost of generating and delivering energy to a consumer (i.e., based on volumetric energy use). These charges are often flat but could also be designed in a variety of forms including inclining or declining block rates,[10] seasonal rates, or time-varying rates.

3. **Demand charge ($ per kW) –** used to recover the costs of generating and delivering electricity to large commercial and industrial consumers. Traditionally, these charges are based on the customer's peak demand (without considering coincidence with the system peak) however many jurisdictions have adopted charges tied to the customer's demand at times of system peak. For instance, California offers coincident demand charges (in addition to non-coincident demand charges) in which the charges differ based on the amount of energy demanded with peak times having the highest charges and off-peak times having the lowest charges.[11] Certain utilities in other states also include coincident demand charges in their rate structures.[12] Demand charge are uncommon for low-usage customer classes, namely, residential consumers; however, some states such as Arizona do so.

This form of traditional rate design is the most commonly used form of rate design by state utilities in the U.S. given its simplicity and strong public acceptance.[13] However, its focus on the

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[9] Lazar, Jim, and Wilson Gonzalez. "Smart Rate Design for a Smart Future." RAP, July 2015, http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-gonzalez-smart-rate-design-july2015.pdf.

[10] These concepts are discussed in Section 6.

[11] CPUC. <http://www.cpuc.ca.gov/General.aspx?id=12188>

[12] For example, Northern Electric Cooperative in South Dakota: https://www.northernelectric.coop/demand

[13] Costello, Ken. "Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives." National Regulatory Research Institute , Apr. 2014,

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use of average costs to determine rates is often criticized as it negatively affects consumers with less on-peak consumption patterns as they would consume more during off-peak periods when prices are low and still pay higher average prices. The use of adjusted test year sales volumes to determine rates as opposed to the actual sales volume of the utility also leads to expected revenue fluctuations.[14] Furthermore, due to the volumetric nature of energy charges and the associated COS approach to determining costs, utilities are incentivized to invest in excessive capital as a means to increase their profits. This can then lead to increased electricity costs for consumers. Figure 4 below shows a summary of the advantages and disadvantages of traditional rate design.

Figure 4. Advantages and disadvantages of traditional rate design

Rate design	Advantages	Disadvantages
Traditional rate design	Simple for the public to understand	Limits customer response
	Focus on utility prudence	Negatively impacts low usage customers
	Perception of fairness due to avoidance of undue price discrimination	Reduces incentives for energy efficiency and distributed generation
	Long-standing rate design paradigm	Incentivizes excessive capital investments increasing electricity system costs

Source: Costello, Ken. "Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives." National Regulatory Research Institute, Apr. 2014, <http://nebula.wsimg.com/5a9a01aeb5f95984861ea4b20d2c903b?AccessKeyId=8AF7098D30C5BF55909C&disposition=0&alloworigin=1.>

Rate design has significant implications for consumer incentives and choices including time of electricity use and amount of electricity consumed. This, in turn, impacts overall electricity demand, the total cost incurred to generate and distribute electricity to consumers, and subsequent incentives of utilities. For this reason, rate design requires a careful balance of the interests of a variety of stakeholders including consumers, utilities, power producers, state institutions, and society.[15]

<http://nebula.wsimg.com/5a9a01aeb5f95984861ea4b20d2c903b?AccessKeyId=8AF7098D30C5BF55909C&disposition=0&alloworigin=1.>

[14] Lazar, Jim, and Wilson Gonzalez. "Smart Rate Design for a Smart Future." RAP, July 2015, http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-gonzalez-smart-rate-design-july2015.pdf.

[15] Bonbright, James C. *Principles of Public Utility Rates*. 1961, http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf.

5 Overview of the current rate design in Hawaii

The HECO Companies and Kauai Island Utility Cooperative ("KIUC") both use the traditional COS rate design mechanism - the form of rate design explained in the previous section.

Figure 5 below shows the applicable end users of each rate classes under HECO Companies.[16]

Figure 5. HECO companies rate classes and applicable end uses

Category	Applicable End Use
Schedule "R" (Residential Service)	Residential lighting, heating, cooking, air conditioning and power in a single family dwelling unit metered and billed separately by the Company. This schedule does not apply where a residence and business are combined;
Schedule "G" (General Service Non-Demand)	General light and/or power loads less than or equal to 5000 kilowatthours per month, and less than or equal to 25 kilowatts, and supplied through a single meter;
Schedule "J" (General Service Demand)	General light and/or power loads which exceed 5000 kilowatthours per month or exceed 25 kilowatts three times within a twelve month period but are less than 300 kilowatts per month, and supplied through a single meter;
Schedule "P" (Large Power Service)	Large light and/or power loads equal or greater than 300 kilowatts, supplied and metered at a single voltage and delivery point
Schedule "DS" (Large Power Directly Served Service)	Large light and/or power loads equal or greater than 300 kilowatts, supplied and metered at a single voltage and delivery point and served directly from a substation. Customers who are eligible for Schedule DS may elect to be served under any other schedule for which they are eligible.
Schedule "F"	**HECO**: public street and highway lighting, and public outdoor park and playground floodlighting service where the customer owns, maintains and operates the lighting fixtures and interconnecting circuits and conversion equipment. This rate is applicable to gaseous discharge lighting (Mercury Vapor) provided the regulator is corrected to power factor equivalent to the addition of one (1) KVAR of capacitors for each kW of name plate rating of the regulator. Under this schedule energy shall be supplied and metered at a nominal voltage of 2400 volt or more, as specified by the Company, except as set forth below under Special Terms and Conditions;
	HELCO: All-night service for street and highway lighting where the customer owns, maintains, and operates the lighting fixtures and all circuits and appurtenances on the customer's side of the delivery point. The service voltage shall be the available distribution voltage at the point of delivery
	MECO: public street and highway lighting service supplied on the Island of Maui / Lanai/ Molokai where the Company owns, maintains and operates the street lighting facilities.

Note: "PUC" refers to Hawaii's Public Utility Commission. These were discussed in detail in the deliverable for Task 1.2.5

[16] HECO Companies. *Rate & Regulations*. Website. <https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/hawaiian-electric-rates>. Access Date: March 8, 2018.

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As shown in the figure above, HELCO and MECO have five rate classes, including "R" Residential, "G" Small Power Use Business, "J" Medium Power Use Business, "P" Large Power Use Business, and "F" Street Lighting. HECO, in addition, has another rate class called "DS" Large Power Directly Served Service.

Similarly, KIUC has eight rate classes, including Schedule "D" Residential, Schedule "G" Small Commercial, Schedule "J" Large Commercial, Schedule "L" Large Power (Primary), Schedule "P" Large Power (Secondary), Schedule "NEM PILOT", Schedule "Q" Modified – Cogenerators, and Schedule "SL" Street Lighting. Among them, Schedule "NEM PILOT" and Schedule "Q" are energy credits payment rate to customers ($ per kWh). The thresholds that KIUC uses to separate the commercial rate classes are different from those of HECO Companies, as described below.[17]

Figure 6. KIUC rate classes and applicable parameters

Category	Applicable parameters
Schedule "G" (General Light & Power Service, Small Commercial)	*Not greater than 30 kW demand and 10,000 kWh use per month*
Schedule "J" (General Light & Power Service, Large Commercial)	*Greater than 30 kW and less than 100 kW demand or 10,000 kWh per month*
Schedule "L" (Large Power, Primary)	*Demand greater than 100 kW – metered on primary side of meter*
Schedule "P" (Large Power, Secondary)	*Demand greater than 100 kW – metered on secondary side of meter*

For the HECO Companies, the current rates for Residential and Small Power Use Business are mainly based on energy charges (i.e., based on volumetric energy rates). Moreover, there is a fixed customer charge ($ per customer per month) and a Green Infrastructure Fee ($ per customer per month) added to all bills. In addition to these, rates for Medium Power Use Business, Large Power Use Business, and Large Power Use Business, Directly Served include demand charge ($ per kW) as well. Furthermore, HECO Companies provide an optional Time-of-Use ("TOU") pilot rate program for Schedule R/ G/ J/ P rate classes.[18] By participating in these pilot program, consumers can save money if they shift their energy use away from high-demand on-peak hours that are at a higher rate.[19]

[17] KIUC. *Energy Rate Adjustment Clause: Rate Data Sheet*. Effective Date: March 1, 2018. Website. <http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/rates/2018%20Rate%20Data.pdf>.

[18] Participation is voluntary. Only HELCO and MECO (not HECO) have Time-of-Use rate schedule for Schedule P.

[19] HECO Companies. *Time-of-Use Program*. Website. <https://www.hawaiianelectric.com/save-energy-and-money/time-of-use-program>. Access date: March 8, 2018.

6 A high-level assessment of potential alternative rate designs

Technological advancements, shifting federal and state energy policies, and structural changes in the electricity industry have required a reconsideration of traditional rate design.[20] To adapt to these changes, utilities and regulators throughout the US continue to propose alternative rate designs that more accurately align utility cost with consumer bills by addressing traditional rate design limitations including disincentives for promoting energy efficiency goals, lack of dynamic price signals, and inefficient pricing. Furthermore, the increasing penetration of renewable energy and distributed generation technologies has required more individualized customer services that accommodate customer-owned generation. The development of advanced metering infrastructure ("AMI") has enabled some utilities to pursue time-varying rates such as Real-Time Pricing ('RTP"). As part of its analysis, the Project Team assessed the following alternative rate designs:

- Tiered rates
    - inclining block rates; and
    - declining block rates
- Higher fixed charges
- Time-varying rates
    - Time-of-Use ("TOU") rates;
    - RTP rates; and
    - Critical Peak Pricing ("CPP") rates

6.1 Tiered rates - inclining and declining block rates

Tiered rate design, also referred to as block pricing, involves the variation of the volumetric distribution charge between blocks of consumption.[21] There are two types of block rates, namely, inclining and declining block rates.

Inclining block rates are one of the most common forms of residential rate design and involve a mechanism by which energy prices increase as the amount of energy consumption increases.[22] This design signals to customers that increased energy usage is associated with higher costs. As a result, inclining block rates can lead to increased consumer savings by reducing the total amount of energy purchases and generation costs. Furthermore, inclining block rate can also

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[20] Wood, Lisa, et al. *"Recovery of Utility Fixed Costs: Utility, Consumer, Environmental, and Economist Perspectives."* Electricity Markets and Policy Group, June 2016, https://emp.lbl.gov/sites/all/files/lbnl-1005742.pdf.

[21] Costello, Ken. "Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives." National Regulatory Research Institute , Apr. 2014, http://nebula.wsimg.com/5a9a01aeb5f95984861ea4b20d2c903b?AccessKeyId=8AF7098D30C5BF55909C&disposition=0&alloworigin=1.

[22] Lazar, Jim. "Global Best Practices in Residential Electric Rate Design." Regulatory Assistance Project, May 2013, https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-globalratedesign-camunicipalratesgroup-2013-may.pdf.

incentivize consumers to self-generate. On the other hand, inclining block rates have drawbacks in terms of revenue instability for utilities whose profits are not decoupled from the amounts of electricity sold and higher costs for consumers who fail to lower consumption in response to higher rates.

Given that rates are decoupled in Hawaii, implementing an inclining block rate design would not threaten utility financial viability. However, a more detailed assessment on how such a rate design without a time-based price signal would impact the state ability to integrate higher penetration of renewable energy is needed. Figure 7 below summarizes the key advantages and disadvantages of inclining block rates.

Declining block rates are designed to decrease energy prices as consumers increase their level of energy consumption. This form of rate design encourages increased energy consumption by consumers and consequently fails to maximize cost savings or encourage adoption of alternative energy sources such as DERs. Accordingly, declining block rates have limited ability to meet most of Hawaii's state energy goals and are not further explored in this report.

Figure 7. Advantages and disadvantages of inclining block rates in Hawaii [23]

Rate design	Advantages	Disadvantages
Inclining block rates	Promote energy conservation	Adverse impacts on consumers who fail to lower energy consumption
	Improve utility system utilization through lower demand	Higher costs for larger, less capacity intensive consumers
	Promote sales in a period of abundant utility supply	Incentivizes excessive capital investments increasing electricity system costs
	Long-standing rate design paradigm	Encourages reduced consumption, which provides for a smaller number of total kWh across which to spread costs of programs and policies, such as RPS, storage, etc.

[23] Multiple sources (all included in the bibliography) used

Example: State of Missouri



In 2017, the Missouri Public Service Commission ordered Kansas City Power & Light to implement the use of inclining block rates to promote energy conservation and consumer savings. The proposed rate structure consists of the following block rates:

1. 12.9 cents per-kilowatt-hour for each of the first 600 kilowatt hours per month
2. 14.9 cents per-kilowatt-hour beyond the threshold

Example: State of California



While the three largest IOUs in California are currently undergoing rate structure reforms and introducing default TOU rates, since the 1970's they have had inclining block rates associated with the level of usage. These rates differed for each utility from year to year. For example, in 2009, one of California's IOUs, PG&E had a rate an inclining block rate structure with the following five tiers:

- Tier 1: $0.122/kWh (595 kWh);
- Tier 2: $0.139/kWh (178 kWh);
- Tier 3: $0.294/kWh (417 kWh);
- Tier 4: $0.404/kWh (493 kWh); and
- Tier 5: $0.404/kWh (remaining kWh consumed).[24]

6.2 Higher fixed charges

Higher fixed charges offer a minor change to the traditional flat rate design by simply increasing the fixed charge portion of consumer bills as a way to ensure revenue stability, recovery of utility fixed costs and mitigate cost shifts between customers. This means that consumers with energy efficiency measures or on-site renewable energy cannot avoid the charges. This approach has pros and cons that need to be carefully weighed. Despite their benefit of providing short-term revenue stability for utilities as well as mitigating potential cost shifts between consumer categories,

[24] PG&E. "PG&E's inclining block electric rates for residential customers: toward a more equitable rate design." June 2011.<ftp://ftp2.cpuc.ca.gov/PG&E20150130ResponseToA1312012Ruling/2011/06/SB_GT&S_0444782.pd>

higher fixed charges can have detrimental impacts on consumers with low demands or with a high reliance on DERs.

Most importantly, higher fixed charges fail to address the key limitation of traditional rate design, lack of proper price signals. At the same time, as the changes to Hawaii's electricity sector evolve, it will be vital to ensure that all possible tools are available to ensure that the utilities are compensated for their costs to remain financially viable companies that have access to capital markets. Thus, while the Project Team does not believe that higher fixed charges in isolation are a suitable way to achieve Hawaii's policy goals, we recognize that this mechanism may merit consideration and more analysis in the future.

6.3 Time-varying rates

Time-varying rates refer to a set of rate design options which reflect some form of time-differentiated pricing structure which allows more efficient consumer response. The most common forms include

- TOU rates;
- RTP rates; and
- CPP rates, all of which are discussed in detail below.

In February 2018, the Hawaii Public Utilities Commission ("HPUC") approved a $205M grid modernization plan proposed by HECO.[1] The plan includes:

- a strategic installation of advanced smart meters for consumers participating in demand response programs or variable rate programs.
- Installation of advanced inverter technology, voltage management tools, and outage management and notification technology by HECO.

6.3.1 TOU rates

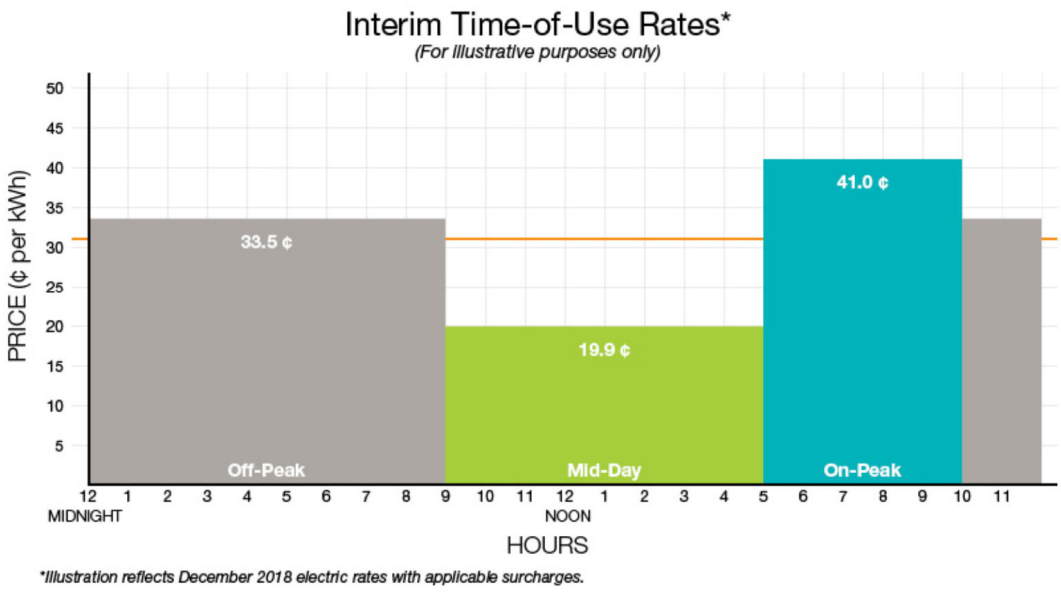
TOU rates provide time-differentiated pricing which reflects the expected cost of providing electricity. TOU rates typically differentiate between "on-peak" and "off-peak" periods to reflect variable prices with on-peak periods having higher energy charges. Accordingly, TOU rates provide improved price signals compared to traditional flat rates and therefore incentivize consumer response by offering the opportunity to maximize consumer savings and encourage the adoption of DERs. To ensure proper customer response to price signals, several factors should be considered in designing TOU rates. First, the price differential between on-peak and off-peak periods should be large enough to incentivize the shifting of consumption to off-peak periods.[25] Furthermore, the duration of price differentiated usage should also be designed to encourage customer response. Generally, shorter time periods allow for easier and more effective customers engagement as opposed to longer periods.

Note however in jurisdictions with high solar penetration, such as Hawaii and California for example, that this breakdown of high cost and low-cost periods has transitioned to reflect the lower afternoon demand that results from high levels of solar, as is shown by the rate breakdown

[25] Chitkara, Aman, et al. "A Review of Alternative Rate Designs." Rocky Mountain Institute, May 2016, https://rmi.org/wp-content/uploads/2017/04/A-Review-of-Alternative-Rate-Designs-2016.pdf.

for HECO in the figure below. On-peak periods are typically limited to weekdays while off-peak periods occur during weekends and holidays.[26] It is important to note that TOU prices are fixed well in advance and therefore do not reflect the actual hourly costs of producing electricity (as opposed to RTP which is explained in the following section) or require the use of smart meters.[27]

Figure 8. Time-of-use rates



Source: HECO, Time-of-Use Program < *https://www.hawaiianelectric.com/products-and-services/save-energy-and-money/time-of-use-program*>

Compared with traditional flat rates, TOU rates provide clearer price signals to consumers as they differentiate prices by time periods and subsequently incentivize consumers to minimize electricity use during high-cost periods. This, in turn, contributes to reduced utility system costs. Research shows that TOU rates reduce overall electricity consumption by as much as 5%.[28] TOU rates are more common for commercial and industrial customers, though such rates have also been offered to residential customers in the forms of pilots more frequently in recent years. Notably, California's three major investor-owned utilities aim to roll out system-wide default

[26] Lazar, Jim, and Wilson Gonzalez. "Smart Rate Design for a Smart Future." RAP, July 2015, http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-gonzalez-smart-rate-design-july2015.pdf.

[27] Lazar, Jim. "Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed ." Regulatory Assistance Project, Apr. 2013, https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-ratedesignconventionalmeters-2013-apr-8.pdf.

[28] Wood, Lisa, et al. "Recovery of Utility Fixed Costs: Utility, Consumer, Environmental, and Economist Perspectives." Electricity Markets and Policy Group, June 2016, https://emp.lbl.gov/sites/all/files/lbnl-1005742.pdf.

TOU rates for 22.5 million of their residential consumers by 2020.[29] Figure 9 below summarizes the key advantages and disadvantages of TOU rates as they relate to impacts on overall market conditions in Hawaii.

The HECO companies currently offer an optional TOU program to increase consumer savings and promote the cost-effective integration of renewable energy.[30] A thorough evaluation of that program will be useful to inform considerations of further TOU program refinement and deployment.

Figure 9. Advantages and disadvantages of TOU rates in Hawaii

Rate design	Advantages	Disadvantages
TOU	Economically efficient; need for less utility capacity additions over time	Aggravation of high utility bills during peak periods
	Avoidance of subsidies to high peak-use utility customers	Potentially skeptical public
	Promotion of demand-side actions to allocate utility costs	Potentially large adverse effect on utility non-price responsive customers

Note: The advantages and disadvantages from the source below have been modified to reflect Hawaii specific market conditions.
Source: Costello, Ken. "Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives." National Regulatory Research Institute, Apr. 2014, <http://nebula.wsimg.com/5a9a01aeb5f95984861ea4b20d2c903b?AccessKeyId=8AF7098D30C5BF55909C&disposition=0&alloworigin=1.>

Example: State of Massachusetts

In 2014, the Massachusetts Department of Public Utilities ("MDPU") committed to transitioning residential consumers to TOU rates with a critical peak pricing overlay as the default rate



[29] Trabish, Herman. "As California leads way with TOU rates, some call for simpler solutions." Utility Dive. September 2, 2018. <https://www.utilitydive.com/news/as-california-leads-way-with-tou-rates-some-call-for-simpler-solutions/532436/>

[30] HECO. Time-of-Use Program. <https://www.hawaiianelectric.com/products-and-services/save-energy-and-money/time-of-use-program>

design within the next several years. The order requires electric distribution companies to offer two basic service TOU options:[31]

1. A TOU pricing which includes a CPP component in which retail electricity prices during on-peak hours (12 pm – 8 pm during weekdays) is priced higher than remaining off-peak hours.

2. A flat rate with a peak time rebate ("PTR") option in which consumers who choose to lower energy consumption during identified peak times receive a payment. This option effectively protects consumers who continue to consume during on-peak periods as they would be able to pay a flat rate.

6.3.2 RTP rates

RTP is a form of rate design which establishes hourly rates based on actual wholesale electricity costs (in restructured/competitive markets) or short run marginal generation costs (in vertically integrated markets).[32] RTP rates require the use of smart meters that can monitor hourly prices based on electricity costs and report usage patterns on an hourly basis. RTP provides proper price signals to consumers by linking wholesale/generation costs with retail electricity prices. Pilot programs have shown that RTP rates can work in terms of altering consumer choice and lead to benefits that exceed associated metering and incremental costs.[33]

Despite its appealing benefits, RTP use is limited due to the fact that it exposes consumers to volatile wholesale energy prices and the technical and implementation cost challenges.[34] Moreover, RTP could have adverse impacts on consumers who fail to shift energy consumption from on-peak to off-peak periods by increasing the average price of electricity they have to pay. Thus, RTP requires consumers to be well-educated about wholesale power markets and price dynamics so that they can effectively respond to price signals. Furthermore, it needs a robust energy service provider or an aggregator market so that consumers have sufficient options to optimize their energy use and manage their bills. Given these hurdles, it remains unclear if RTP rates would be appropriate for smaller consumers including residential and small-scale

[31] "Massachusetts DPU Says Time of Use Pricing Will Be the Default for All Customers | Smart Grid Legal News. Smart Grid Legal News, 26 June 2014, https://www.smartgridlegalnews.com/demand-response/massachusetts-dpu-says-time-of-use-pricing-will-be-the-default-for-all-customers/.

[32] Lazar, Jim, and Wilson Gonzalez. "Smart Rate Design for a Smart Future." RAP, July 2015, http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-gonzalez-smart-rate-design-july2015.pdf.

[33] Costello, Ken. "Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives." National Regulatory Research Institute, Apr. 2014, http://nebula.wsimg.com/5a9a01aeb5f95984861ea4b20d2c903b?AccessKeyId=8AF7098D30C5BF55909C&disposition=0&alloworigin=1.

[34] Ibid

commercial consumers. Figure 10 below provides a summary of the key advantages and disadvantages of RTP rates as they relate to the overall impacts on market conditions in Hawaii.

The HECO companies and KIUC currently do not offer an RTP program to any of their customers.

Figure 10. Advantages and disadvantages of RTP rates in Hawaii

Rate design	Advantages	Disadvantages
RTP	Leads to a more efficient use of energy and capacity resources by utilities and consumers	Exposes consumers to highly volatile electricity prices
	Allows easier integration of renewable energy	Adverse impact on consumers who fail to shift consumption from on-peak to off-peak periods
	Improves load flexibility	Requires the installation of smart meters; high implementation cost

Source: Costello, Ken. "Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives." National Regulatory Research Institute, Apr. 2014, <http://nebula.wsimg.com/5a9a01aeb5f95984861ea4b20d2c903b?AccessKeyId=8AF7098D30C5BF55909C&disposition=0&alloworigin=1.>

Example: State of Illinois



Illinois is the only state in the US whose two major utilities, Ameren Illinois and Commonwealth Edison ("ComEd") offer comprehensive opt-in dynamic "real-time pricing" programs for residential consumers in which electricity prices offered to consumers vary hourly, based on wholesale electricity prices.[35] Analysis conducted by the Citizens Utility Board shows that 97% of ComEd's customers could save on average $86.63 (approximately 13%) annually only through participating in the real-time pricing program.

6.3.3 CPP rates

CPP rates allow utilities to set substantially higher prices during "critical peak periods" which occur on specific hours of "critical peak days" of the year. The number of critical periods is often capped for a given year. Customers are therefore incentivized to lower their energy consumption

[35] Jeff, and David Kolata. "The Costs and Benefits of Real-Time Pricin." Citizens Utility Board, Nov. 2017, https://citizensutilityboard.org/wp-content/uploads/2017/11/FinalRealTimePricingWhitepaper.pdf.

during these periods and subsequently benefit from lower electricity bills. However, this form of rate design reduces the incentivize for consumers to reduce energy consumption in off-peak periods.[36] This rate design also requires the use of AMI. A slight variation of CPP rate is a **Critical Peak Rebate ("CPR") or Peak Time Rebate ("PTR")** in which the utility pays consumers for every kWh of electricity reduced during critical peak periods.[37] The figure below summarizes the key advantages and disadvantages of CPP rates as applicable to Hawaii.

Currently, utilities in Hawaii do not offer CPP rates to consumers. However, given the increasing penetration of solar power in Hawaii and the need to effectively manage peak load, if implemented strategically, CPP rates could offer significant benefits and could merit further evaluation.

Figure 11. Advantages and disadvantages of Critical Peak Pricing in Hawaii

Rate design	Advantages	Disadvantages
Critical Peak Pricing	Significant load reductions in peak periods	Adverse impacts on consumers who fail to reduce electricity consumption during "critical periods"
	Significant cost savings for consumers who lower electricity consumption during "critical periods"	Provides no consumer incentives to reduce energy consumption during hours outside of "critical periods"

Source: Badtke-Berkow, Mina, et al. "Making the Most of Time-Variant Electricity Pricing." Environmental Defense Fund, 2015, <https://www.edf.org/sites/default/files/content/a_primer_on_tvp_for_edf_webpage.pdf.>

Example: State of California

In the US, the largest residential CPP deployment is offered by PG&E. PG&E started offering its CPP rate in May 2008, with the initiation of its system-wide smart metering deployment.
The CPP rate features:

- Applicable during summer with peak period 2 pm – 6 pm
- Maximum number of peak events limited to 15 per summer
- Peak surcharge set at 60 cents/kWh
- Off-peak discounts vary between 3 cents and 4 cents/kWh



[36] Badtke-Berkow, Mina, et al. "Making the Most of Time-Variant Electricity Pricing." Environmental Defense Fund, 2015, https://www.edf.org/sites/default/files/content/a_primer_on_tvp_for_edf_webpage.pdf.

[37] Ibid

6.4 Comparative impacts of alternative rate designs on energy savings

The relative impacts of the alternative rate designs discussed in the prior section, including those on energy savings, vary depending on specific design characteristics and prevailing market conditions in the jurisdiction of implementation. Thus, they are not directly comparable to one another. We list them here merely to share experience from other jurisdictions and to provide an order of magnitude impact that such rate designs have had elsewhere. Figure 12 below summarizes the percentage of annual energy savings from select rate design pilots conducted by the following utilities:[38]

- Sacramento Municipal Utility District ("SMUD") of California;
- Xcel Energy of Colorado;
- Baltimore Gas and Electric ("BGE") of Maryland; and
- Public Service Electric and Gas Company ("PSEG") of New Jersey.

Figure 12. Percentage of energy savings from select rate pilots

Pilot name	Pilot period	Rate design	% of energy savings
SMUD Smart Pricing Options Study	2011 - 2013	Opt-in TOU	0.9 - 1.1%
		Opt-in CPP	1.0% - 3.5%
		Default TOU	1.30%
		Default CPP	2.60%
		Default TOU+CPP	1.30%
Xcel SmartGridCity	2010 - 2013	TOU	2%
		CPP	1.5 - 7.6%
		PTR	3.5 - 5%
BGE Smart Energy Pricing Pilot	2008	TOU + CPP	1.05%
		PTR	0.56%
PSEG myPower Pricing Pilot	2006 - 2007	TOU	3.8%

Note: Ranges for % in energy savings represent values across two phases of the given pilot. Furthermore, the values listed represent average values across phases.
Source: Baatz, Brendon. "Rate Design Matters: The Intersection of Rate Design and Energy Efficiency." March 2017. American Council for an Energy-Efficient Economy.

As shown in the figure, the percentage of annual energy savings varies widely depending on the form of rate design used and the jurisdiction in which the pilot is conducted. Specifically, impacts on energy savings vary due to factors including the type of customer group, enabling technologies used, and level of consumer responsiveness, among others. Generally, based on the pilot results noted above, CPP and PTR result in higher energy savings than TOU rates

[38] Please note that the table includes rates design pilots for which there is specific data on annual energy savings.

(considering both default and opt-in variations). However, care must be taken when drawing conclusions regarding the relative effectiveness of these rate designs given the factors above.

7 Evaluation of alternative rate designs as compared to ownership and regulatory model changes

In accordance with the scope of Tasks 3.1.1 and 3.1.2, the Project team conducted a high-level assessment of the extent to which the benefits of ownership and regulatory model changes can be achieved through rate design changes and the relative ability of rate design changes to:

(I) maximize consumer cost savings;
(ii) enable a competitive distribution system;
(iii) eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation; and
(iv) align management, ownership, and ratepayer interests.[39]

We discuss each of these in the subsections below.

It is important to note that a detailed quantitative analysis would be required to draw more specific conclusions about the relative effectiveness of rate design changes in achieving the benefits from ownership and regulatory model changes. Rate design is inherently interlinked with ownership, and regulatory models and care must be taken to ensure that rate design changes serve as effective complimentary tools and are consistent with overall policy goals in light of the prevailing ownership and regulatory model.

7.1 Ability of changes in rate design to maximize consumer cost savings

If designed and implemented correctly, rate design changes have the potential to optimize consumer cost savings. However, this is dependent upon consumers responding to price signals by shifting energy usage from on-peak to off-peak periods. By moving consumption to off-peak periods, consumers could reduce overall utility costs for additional generation capacity which would subsequently lead to lower rates. However, depending on program design, rate design changes such as time-varying rates could have adverse impacts on residential consumers who are unable to shift usage from on-peak to off-peak periods whether due to inflexible electric demand or a lack of enabling technology. In this context, the inability to shift from on-peak to off-peak periods would lead to higher monthly bills for these consumer groups.[40]

Regulatory model changes, if implemented correctly, also have the potential to result in significant cost savings for consumers. As discussed in the memo for Task 2.2.1, the Performance-Based Regulatory model ("PBR"), including both variants of outcomes-based PBR and conventional PBR, could result in reduced consumer rates as they allow the regulator to set

[39] Note: the ranking on regulatory models included an additional criteria of transition costs

[40] Colgan, John T., et al. "Guidance for Utilities Commissions on Time of Use Rates: A Shared Perspective from Consumer and Clean Energy Advocates." 15 July 2017, <https://uspirg.org/sites/pirg/files/reports/TOU-Paper-7.17.17.pdf>

incentives and penalties tailored to the specific goal of affordable rates. Furthermore, rate design mechanisms can be effective complementary tools to the PBR regulatory model.

On the other hand, the relative effectiveness of ownership model changes would depend on prevailing regulatory practices. As discussed in the memo for Task 1.2.5, for instance, the efficacy of the co-op model in lowering rates would primarily depend on the priorities of the customer-owners. Similarly, the Single Buyer model, given its ability to create a competitive procurement process can result in lower consumer rates driven by lower generation prices. However, the relative amount of consumer savings would depend on the management and procurement practices of the SB.

Overall, rate design, regulatory, and ownership model changes are all subject to varying levels of implementation risks. The relative effectiveness of such changes would depend on program design and prevailing market conditions at the time of implementation.

7.2 Ability of changes in rate design to enable a competitive distribution system

Time-varying rate design has the potential to advance customer driven DERs as it provides price signals that better reflect the costs associated with producing electricity. By doing so, it allows customers to make better-informed decisions about their energy usage and subsequently enable efficient use of DER resources.[41] For instance, during on-peak periods in which the grid's power supply is constrained, consumers could shift energy consumption from grid source electricity to on-site DER. This system would allow consumers to rely on grid-sourced electricity during off-peak periods and use DERs during on-peak periods, effectively reducing their consumer bills while also contributing to lower utility grid costs.[42] Furthermore, such rate designs could also improve the economic competitiveness of DERs.

Ownership model changes in isolation including co-ops, IOUs, and the SB model have limited abilities to promote distribution system competition, specifically, in promoting DERs due to bias towards building their generation instead of encouraging DERs (for co-ops and IOUs) or lack of incentives to do so. On the other hand, regulatory model changes, such as a shift toward the PBR model, has the potential to increase competition at the distribution level, by designing incentives and penalties specific to the goal enabling a competitive distribution system. It is important to note that the implementation of ownership or regulatory changes, such as a shift toward the PBR model, would still require corresponding revisions to rate design in order to enable a competitive distribution system.

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[41] Badtke-Berkow, Mina, et al. "Making the Most of Time-Variant Electricity Pricing." Environmental Defense Fund, 2015, https://www.edf.org/sites/default/files/content/a_primer_on_tvp_for_edf_webpage.pdf.

[42] Ibid

7.3 Ability of changes in rate design to eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation

As discussed in prior memos, under vertically integrated utilities, conflict of interest in the areas of energy resource planning, delivery, and regulation is primarily addressed through the separation of planning and operational control from investment and ownership. IOUs earn profits on capital investments, creating an economic incentive for them to favor IOU-owned assets. This has historically translated into a bias for thermal generation (as the IOUs are not allowed to own renewable generation) as well as wires investments. Customer-sited assets such as DERs would offset investments in centralized generation assets and thereby reduce utility revenues, although one might argue that over the long term, DER expansion might require additional wires investment.

While rate design changes would not enable the separation of planning and operational control from investment and ownership, they can play a significant role in utility resource planning strategy. For instance, a shift from traditional flat rate design to some form of time-varying rate would improve energy resource planning by incentivizing low-cost planning and potentially encourage utility adoption of DERs by ensuring revenue stability. Furthermore, it would encourage more efficient consumption of electricity and provide consumers an economic incentive to adopt DERs. At the same time, there are other forms of rate design that could be less favorable toward DERs.

Regulatory model changes including a shift toward the PBR model, despite not being able to result in full separation of planning and operational control from investment and ownership, could provide incentives and penalties tailored to the goal of reducing conflicts of interest. However, the Hybrid model could result in separation at the distribution level. These regulatory models are discussed in detail in the memo for Task 2.2.1.

On the other hand, as discussed in the memo for Task 1.2.5, changes from the status quo ownership model to the SB (outside of the utility) model would effectively eliminate the conflict of interest in energy resource planning, delivery, and regulation as it completely separates the ownership of generation and transmission assets from operational control. In a similar fashion, a shift towards a co-op ownership model could reduce conflicts of interest given that co-ops would generally be more favorable toward customer owned DERs.

7.4 Ability of changes in rate design to align management, ownership, and ratepayer interests

As noted in prior memos, the key principle that guides the alignment of management, ownership and ratepayer interests is the separation of ownership, procurement, and operations. While rate design changes only address the mechanism of structuring consumer bills and do not effect change in the ownership and regulatory regime (i.e., enable the separation of ownership, procurement, and operations, depending on program design and prevailing ownership and regulatory structures) they can offer useful benefits that can better align stakeholder interests. For instance, if utilities are required to invest capital in the grid to accommodate DERs, rate design changes such as time-varying rates, can better align consumer and utility interests.

Under the status quo IOU ownership model, the utility's primary interest is to maximize financial returns to utility owners and shareholders. On the other hand, ratepayers' primary interest is to reduce electricity rates. While rate design changes such as time-varying rates and inclining block rates would meet the ratepayer interest in terms of increasing savings and promoting the adoption of DERs, they can adversely impact prevailing ownership and management interests by reducing the number of consumers under each rate class and subsequently increasing rates for remaining customer groups from which utilities can recover costs, given the decoupling regime in Hawaii.

In summary, aligning management, ownership, and ratepayer interests would require a careful combination of ownership, regulatory, and rate design changes. For instance, a transition from the status quo IOU ownership model to an SB (outside of the utility) model would better align stakeholder interests as the SB would be a stand-alone, not-for-profit entity and not own any generation or transmission assets which would cause it to favor utility interests over that of ratepayers. Alternatively, a transition to a co-op form of ownership would also effectively address misalignment of utility and ratepayer interests as co-ops are owned and controlled by their members who are also customers, as is the case for the island of Kauai. In both cases, a complimentary change in rate design is necessary to ensure the effective alignment of management, ownership, and ratepayer interests.

8 Conclusion

In assessing whether the benefits of ownership and regulatory model changes can be achieved through changes to Hawaii's existing rate design, the Project Team evaluated a broad range of alternative rate designs including tiered rates (inclining and declining block rates), higher fixed charges, and time-varying rates (Time-of-Use ("TOU") rates, Real-Time Pricing ("RTP"), Critical Peak Pricing ("CPP")). Based on a high-level qualitative assessment of these rate designs, the Project Team concluded that rate design changes can be effective complementary mechanisms to ownership and regulatory changes and could help achieve some of Hawaii's state energy goals such as increasing the adoption of DERs and other consumer side resources, lowering peak demand, and encouraging energy conservation.

Rate design has significant implications for utility and consumer incentives. On the consumer side, rate design is a key driver of when electricity is consumed and how much of it is consumed. Accordingly, rate design impacts overall levels of electricity demand for utilities, and as a result, the total cost incurred to generate and distribute electricity to consumers. If designed appropriately, rate design can be a useful complementary mechanism to ownership and regulatory models and can contribute to balancing the interests of consumers, utilities, and policy makers alike. For instance, when used in conjunction with a PBR regulatory model, rate design can serve as a useful mechanism to incentivize utilities to consider distributed generation in the utility planning process and accordingly meet distributed generation targets. In this case, rate design can play an essential role in balancing utility and customer interests, while advancing the priorities of policymakers. While this is one example of how rate design can be paired with a regulatory model, there are several combinations of rate design and ownership or regulatory models that can be considered to ensure the alignment of stakeholder interests, increased adoption of consumer side resources, and enhancement of a competitive distribution system.

It is important to note that the relative effectiveness of rate designs and their ability to achieve Hawaii's energy goals are best assessed in light of any ultimate changes in ownership model or regulatory model. In order to do so, a detailed quantitative analysis would be required to identify the relative benefits of rate design changes and the most effective combinations of rate design with selected ownership and regulatory models.

9 Appendix A: Scope of work to which this deliverable responds

Task 3.1.1 Assessing whether benefits of changes from ownership and regulatory model changes could be accomplished through changes in rate design. CONTRACTOR shall provide a qualitative discussion on the extent benefits of ownership and regulatory model changes, including the alignment of utility interests with State policy, can be accomplished through changes in rate design.

DELIVERABLE FOR TASK 3.1.1. CONTRACTOR shall provide its conclusions and all work related to assessing whether the benefits of changes in ownership and regulatory model could be accomplished through changes in rate design. CONTRACTOR shall evaluate different potential changes in rate design qualitatively to consider the kinds of benefits they might offer the Hawaii electric power system. CONTRACTOR shall list the benefits and compare them to the benefits from the proposed changes to the ownership and regulatory model. CONTRACTOR shall then qualitatively assess them to consider whether the rate design changes can have a sufficiently large impact to be considered comparable to the ownership and regulatory model changes. The CONTRACTOR shall provide a written summary of the findings in MS Word and Power Point. CONTRACTOR shall submit deliverable for TASK 3.1.1 to the STATE for approval.

Task 3.1.2. Assessing how rate design compares to regulatory and ownership model changes considering overall market conditions. CONTRACTOR shall evaluate the ability of changes in rate design relative to ownership and regulatory model changes to (a) maximize consumer cost savings; (b) enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs; (c) eliminate or reduce conflicts of interest in energy resource planning, delivery and regulation; and (d) align management, ownership, and ratepayer interests.

DELIVERABLE FOR TASK 3.1.2. CONTRACTOR shall provide its conclusions and all work related to considering how rate design compares to regulatory and ownership model changes in terms of maximizing consumer savings, enabling a competitive distribution system, reducing conflicts of interest in energy planning and dispatch, and aligning management, ownership, and ratepayer interests. CONTRACTOR shall consider different potential rate designs and the maximum possible impact in percentage terms that these rate designs might have on savings based on previous experience. In addition, CONTRACTOR shall consider the impact rate designs have on these overall market conditions and whether any changes to rate design could shift them. CONTRACTOR shall provide a written summary of the findings in MS Word and Power Point. CONTRACTOR shall submit deliverable for TASK 3.1.2 to the STATE for approval.

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Assessment of Hawaii's electricity sector management: comparison of independent county with multi-county models

working paper prepared by London Economics International LLC for the State of Hawaii with support from Meister Consultants Group

September 26, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership and regulatory models that can support the State in achieving its energy goals. This document, which corresponds to Task 3.1.3, is one of several working papers associated with that engagement. This paper assesses two models when it comes to the management of Hawaii's electricity sector: (1) independent single-county model; and (2) multi-county model.

The single-county model is the status quo because the operations and management of electric systems are standalone and independent of each county (island). In contrast, under the multi-county model, two or more counties are assumed to be interconnected via inter-island transmission lines, which enable joint operations and dispatch resources these counties. Our preliminary evaluation of these models shows that the multi-county model works better when the models are evaluated relative to the state criteria.

Finally, the Project Team analyzed the recommended ownership and regulatory models under the single-county vs. multi-county approaches. We found that the cooperative model would be easier to implement under the single-county approach while the Single Buyer outside the utility model, Integrated Grid Operator, and Light Hawaii Electricity Reliability Administrator ("HERA") model would be more cost-effective under the multi-county approach. Meanwhile, other ownership and regulatory models such as the performance-based regulation ("PBR") and distribution system platform provider ("DSPP") would not be affected significantly whether the management of the electric systems is single county or multi-county.

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List of acronyms

CEO	Chief Executive Officer
DBEDT	Hawaii Department of Business Economic Development and Tourism
DER	Distributed energy resources
DSPP	Distributed System Platform Provider
HECO	Hawaiian Electric Company
HELCO	Hawaii Electric Light Company
HERA	Hawaii Electricity Reliability Administrator
HSEO	Hawaii State Energy Office
IGO	Integrated Grid Operator
IPP	Independent power producers
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company
PBR	Performance-based ratemaking
PSIP	Power Supply Improvement Plan
PUC	Public Utilities Commission
RPS	Renewable Portfolio Standards

1 Executive summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models that can support the State in achieving its energy goals. This working paper, which responds to Task 3.1.3 in the project scope of work, provides an assessment of managing Hawaii's electricity sector with each county operating independently as compared to a multi-county model.

The Project Team analyzed the single-county vs. the multi-county models from the perspective of utilities' management and operations—how the utilities operate the electricity system—from sourcing the supply to dispatching the electrons. The **single-county model** is the status quo because grids in each county (island) are isolated from those in other counties. Therefore, the operations and management of electric systems are standalone and independent in each county. In contrast, the **multi-county model** has two or more counties that are interconnected via inter-island transmission lines, which enable joint operations and the dispatch of resources in two or more counties.

Each model has its advantages and disadvantages. The current single-county model provides easier management and operations of the electricity system in each county because the local utility leadership can make operational decisions immediately. Moreover, local utilities are likely to be more aware of what is happening in their respective counties, enabling them to act based on county-specific needs. On the other hand, a multi-county model could better utilize the available renewable resources in each county because of the inter-island connection. This would then potentially lower the total cost of management and operations, thereby, reducing retail rates for electric consumers. However, the upfront costs of building and operating the interisland cables are high, making it a controversial topic that triggers significant socio-economic challenges in the past.

Moreover, the Project Team assessed the performance of each model relative to the policy goals established by the State for the energy sector. We found that the multi-county model better addresses 3 of the State's priorities while the single-county model is better suited for 2 of the State's priorities. The multi-county model received a better rating in the ability to meet state energy goals, maximize consumer cost savings, and enable a competitive distribution system. In contrast, the single-county model works better in addressing conflicts of interest and aligning stakeholder interests.

Finally, the Project Team performed an analysis of how the single-county and multi-county approach would affect the implementation of the recommended ownership and regulatory models. While most of the models would not be impacted by either approach, it would be easier to implement the cooperative model under the single-county approach. Meanwhile, the Single

Buyer outside the utility model[1], Integrated Grid Operator[2] and Light HERA[3] (segments of the Hybrid regulatory model) would be more cost-effective under the multi-county approach (see Section 6).

[1] The single buyer is not only ring-fenced from the other business entities of the utility but is outside of the utility.

[2] As discussed in Task 2.2.1, the functions of the ISO and the independent distribution system operator are combined in an Independent Grid Operator ("IGO") model. Given the smaller size of Hawaii's transmission systems (compared to other jurisdictions), combining these two regulatory models would be more effective and efficient in its context.

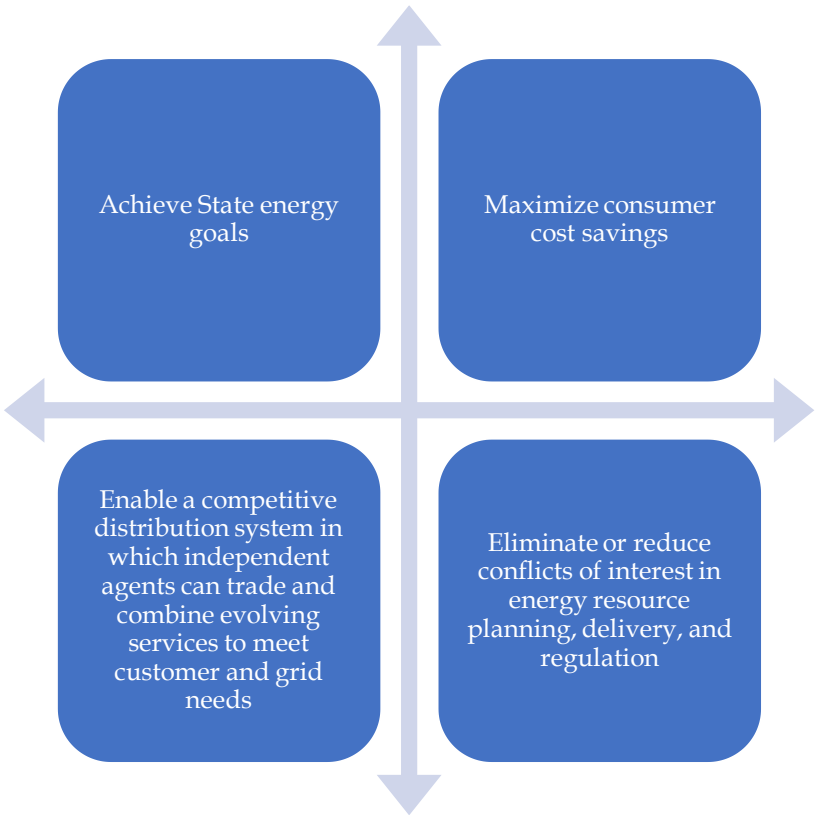
[3] A Light HERA was also considered as an alternative option to HERA. Under the Light HERA, HERA (the entity) could perform as an ombudsman and an appeals body focused on hosting capacity and interconnection. It would have the technical capability to set target timeframes and standard models for calculating interconnection costs—in cases when a customer wants to challenge utility interconnection behavior or lack of hosting capacity transparency. See Task. 2.1.1. for more description of the Light HERA.

2 Introduction and scope

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models, which can facilitate the achievement of the State's energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[4] was contracted to perform this study.[5]

The project aims to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[6] (Figure 1).

Figure 1. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

The study will help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models that could serve each county. Moreover, it

[4] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[5] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[6] House Bill No. 1700 Relating to the State Budget.

will also aid in identifying the process that must be followed in forming such ownership and regulatory models as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county, the ability to diversify energy resources, economic development, reducing greenhouse gas emissions, improving system reliability and power quality, and lowering costs to all consumers.[7]

This deliverable is responsive to Task 3.1.3 in the project scope of work.[8] It analyzes the relative advantages and disadvantages of the models, that is when each county is operating independently or collectively as a part of a multi-county model, which may involve the ownership of electric utilities in two or more counties. The evaluation is governed by a set of criteria, which assess the models in terms of ability to 1) achieve State energy goals; 2) maximize consumer cost savings; 3) enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs; and 4) eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation.

[7] Hawaii Contract No. 65595. Scope of Services.

[8] This task involves a high-level overview, which may not include all of the detailed nuances, conditions and exceptions that may apply under certain circumstances, which are beyond the scope of this task.

3 Overview of single-county model vs. multi-county model

Currently, Hawaiian Electric Company, Inc ("HECO") and its subsidiaries, Maui Electric Company ("MECO") and Hawaii Electric Light Company ("HELCO")—collectively known as the HECO Companies—serve about 95% of Hawaii's population through its electric utilities. The island of Kauai is served by the Kauai Island Utility Cooperative ("KIUC"), which serves the remaining 5% of Hawaii's customers. The discussion in this memo will focus on the utilities in the three counties only because the electric system in Kauai is operated separately by KIUC and there is little chance that it would be operated along with other utilities.

In this section, the Project Team focuses on the perspective of utilities' management and operations. Currently, the HECO Companies operate as a single-county model; each utility covers a single county. MECO and HELCO are subsidiaries under HECO, and certain functions and teams are shared or closely collaborated among these utilities. However, MECO and HELCO are separate entities that manage and operate their systems independently, and as required by the Hawaii Public Utilities Commission ("PUC"), HECO, MECO, and HELCO submit rate filings separately. Moreover, the grids in each county are isolated from each other—this means that each county's utility has its own control center and operates the system independently. Therefore, from the perspective of utilities' management and operations, the status quo is regarded as a single-county model. Figure 2 summarizes the services that are shared or independently provided under HECO Companies' One Company Initiative.

Figure 2. Services that are shared or independently provided under HECO Companies' One Company Initiative

Shared services	Operating areas that are moving to be shared services	Independent areas
• Legal • Regulatory • System Planning • Independent Power Producer Negotiations and Renewable Acquisitions • Environmental Consulting • IT services related to Enterprise Information Systems • Finance • Customer Service	• Power Supply • Energy Delivery • System Operation	• Government and Community Affairs • Public Affairs • Corporate Relations • Enterprise Operations Services • Business Development and Strategic Planning

Note: Independent areas were identified by comparing the list of departments under shared services with the list of all departments in HECO's website.

Source: HECO Companies. *Hawaiian Electric Company 2017 Test Year Rate Case – One Company Initiative*. Docket No. 2016-0328. Page 1. HEI. *Corporate Governance*. Website. <http://www.hei.com/CustomPage/Index?keyGenPage=1073751876>. Access Date: September 5, 2018.

Alternatively, there could be a multi-county model where the utility in each county operates in more enhanced coordination with other county utilities. This would mean that the utility would manage and operate the system in two or more counties—this requires inter-island transmission that connects these counties. Once the grids are connected, the utility would be able to manage

the demand and supply in these counties jointly, requiring one control center only for the dispatch of resources.

The comparison of the single-county and multi-county models is below.

3.1 Similarities between single-county and multi-county models

The single-county and multi-county models have several similarities, and some of them are discussed below:

- Neither model **depends on the ownership of the utilities**. From the perspective of utilities' management, the single-county model holds as long as each utility covers one and only one county while the multi-county model applies when a utility works in two or more counties, which are interconnected. These definitions do not change if the ownership of utility changes. For instance, if there is a cooperative that covers two counties and they are interconnected, it is still considered as a multi-county model.

- Both models **involve cooperation and collaboration among different counties**, to some extent. Under the current single-county model, MECO and HELCO are independent entities but are subsidiaries of HECO. In fact, some of their management team have worked or continue to work for two entities. For instance, currently, the same Board of Directors serves both MECO and HELCO and all of them are working or have worked as top executives at HECO. The executive management team of HECO includes both the Presidents of HELCO and MECO. Moreover, some departments provide supportive services (or "shared services")—such as legal, regulatory, system planning, independent power producer negotiations and renewable acquisitions, environmental consulting, IT services related to Enterprise Information Systems and finance—for HECO, MECO, and HELCO.[9] Meanwhile, some departments, including those that require communication with the local community on the ground, are operated within HECO, MECO, and HELCO separately. Moreover, the HECO Companies are considering expanding shared services to the core operating areas of Power Supply, Energy Delivery, and System Operation.[10] This structure means having or implementing a reporting line within one single company.

  However, if some or all the islands (except Kauai) become interconnected under the multi-county model, HECO could manage the single integrated network, increasing the level of cooperation and collaboration among different counties further. For instance, the management of the control room could be under one team because one interconnected system would cover multiple counties.

[9] HECO Companies. *Hawaiian Electric Company 2017 Test Year Rate Case – One Company Initiative*. Docket No. 2016-0328. Page 1.

[10] Ibid, page 2.

- Under both models, the utilities take the broad picture of multi-counties into account in their **strategic plans**. This is obvious under the multi-county model if two or more counties are interconnected. However, even under the current single-county model, HECO Companies have one single filing that presents a general picture of three counties covered by HECO, MECO, and HELCO in the strategic plans. Strategic plans referred to by the Project Team show that they share similar or complementing grid modernization strategy, sustainability reports, and power supply improvement plans.

3.2 Differences between the single-county model and multi-county model

From the utility's perspective, the fundamental difference between the single-county model and multi-county model is the presence of inter-island transmission lines in the latter model. The inter-island transmission would connect two or more counties with each other and, thereby, enable a utility to make strategic plans based on aggregated supply and demand and manage and operate the electric system of two or more counties.

4 Advantages and disadvantages of each model

In this section, we provide a high-level overview of the potential advantages and disadvantages of each model. Figure 3 summarizes them.

Figure 3. Advantages and disadvantages of each model

Utilities' management and operations	Single-county model (status quo)	Multi-county model
Advantages	• Flexible structure as both multi-county strategies and county-specific plans exist, given the parent-subsidiaries relationship • County-specific opinions have greater impact on the local electric system	• Total management and operation costs could be lower • The retail rates for electric consumers could be lower • Better utilization of available renewable resources and potentially reduce the volatility of electricity rates
Disadvantages	• Mismatch of resources exist – counties with high demand have limited renewable resources • Coordination between counties is limited due to unavailable infrastructure (no interisland connection) • Duplication of functional teams and control centers in each county	• Costs of building interisland transmission could be high • Political and social challenges for building interisland transmission are significant • Potential environmental impacts

4.1 Single-county model

As mentioned earlier, the single-county model is the current structure (status quo) in Hawaii, where there is no inter-island transmission connection. As a result, the utility of each island is relatively independent.

4.1.1 Advantages

Although MECO and HELCO are subsidiaries of HECO and the management and operations in each county are independent, certain collaboration and shared resources/services still exist. HECO, as the parent company, makes decisions on broad strategic plans together with MECO and HELCO while the local utility decides specific projects implementation for their respective county. For instance, on procurement, MECO and HELCO coordinate with HECO staff to get their support in negotiations with independent power producers and renewable acquisitions but when it comes to interconnection, technical staff in each local utility company process the interconnection request. This procedure enables collaboration among counties but also allows flexibility in implementation cognizant of the unique characteristics of each county.

Moreover, some stakeholders on neighboring counties oppose inter-island transmission because the interconnection between islands may cause unintended advantages for Oahu at the cost of

neighboring counties.[11] Naturally, the single-county model (status quo) has broader social support because the current structure (without inter-island transmission) gives greater local control of the electric system compared with the system in a multi-county model (with inter-island transmission).

4.1.2 Disadvantages

The absence of inter-island transmission likely leads to a mismatch of resources among counties. For instance, the City and County of Honolulu has the highest demand among all the counties, but the renewable resources are relatively limited there compared with the wind resources in the County of Maui and geothermal resources in the County of Hawaii. Under the single-county model, resources are dispatched to each county (island) independently, resulting in one control center and functional teams per county (island). Without the inter-island transmission, coordination in terms of dispatch and system operations between counties is limited. Therefore, the management and operations under the single-county model are observed to be less efficient compared with the multi-county model.

4.2 Multi-county model

Inter-island transmission that connects two or more counties is the foundation of the multi-county model and the reason why it is differentiated from a single-county model. It enables two or more interconnected counties to be managed and operated by one utility. Therefore, demand and supply on these counties can be aggregated and dispatched together in one system.

4.2.1 Advantages

Interconnected counties only need one control center and set of functional teams that cover multiple counties. This would lower the staff costs. The interconnected system would help to better utilize excess renewable resources from certain counties (i.e., reduce the curtailment) to meet the demand from other counties. If designed and operated effectively, this would help reduce the volatility of electricity rates by replacing local oil-fired generation with renewable generation from other counties. Moreover, an efficient system could potentially lower the retail rates for electric consumers as well.

4.2.2 Disadvantages

However, economic, political and social challenges for inter-island transmission are significant. First, many stakeholders interviewed for this Study are concerned about the high capital costs of such an inter-island transmission project and whether that would result in higher electric rates for consumers. HECO Companies evaluated the cost of inter-island transmission among Oahu, Maui, and Hawaii Island and determined that it would be around $600 million.[12] However, whether the benefit will be higher than the costs may require further analysis, which is not part

[11] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 3. Page H-52.

[12] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 1. Page 3-14.

of the scope of this Study. Second, some stakeholders from neighboring counties question whether the interconnection will benefit Oahu only, especially at the costs of neighboring counties.[13] Stakeholders are also concerned that county-specific would not be heard if multiple counties are connected to be one system. Third, some stakeholders are concerned with the potential negative impact on the environment.[14] Finally, it would be challenging to obtain consensus on the establishment of an inter-island transmission of the communities in the neighboring counties. Box 1 carries a discussion of prevailing opinions and studies related to these concerns.

Controversial topic: Inter-island transmission in the Hawaii context

The building of an inter-island transmission has always been a controversial topic in Hawaii for a long period of time. In 2013, Docket 2013-0169—which discusses whether inter-island cables were in the public interest—was opened but it has been inactive for a while.

Studies that revealed different opinions had also been conducted. For instance, DBEDT analyzed the costs and benefits of an inter-island transmission cable connecting Oahu and Maui in 2013 and concluded on an economic basis that the net benefits of the inter-island connection outweigh the costs. In addition to the overall cost savings to ratepayers, the report also stated that the inter-island transmission cable would reduce dependence on fossil fuels, lower fuel costs and provide less exposure to price volatility, increase flexibility in siting new renewable energy generation, reduce curtailment of renewable generation, and lower the operating reserve requirements, among others.

Meanwhile, the HECO Companies—as stated in the 2014 Power Supply Improvement Plan ("PSIP")—evaluated the interconnection between Oahu and Maui island, but found that the gross benefits were "*substantially less than the estimated cost of a cable*." However, in the December 2016 PSIP, the HECO Companies evaluated the potential inter-island transmission among Oahu, Maui, and Hawaii Island again by conducting a break-even analysis. The analysis assumes various copper plate configurations and then compares the benefits against $600 million. According to E3 Copper-plate Plans, the present value benefit of the cable is $3 billion, which is "*sufficiently large enough to justify further analysis of the feasibility, configuration and cost effectiveness of inter-island interconnections*."

Source: DBEDT. *Initial Public Comments in Response to Hawaii PUC Order No. 31356* (Docket No. 2013-0169). HECO Companies. 2016 PSIP.

[13] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 3. Page H-52.

[14] For instance, an inter-island cable might have impacts on marine mammals and deep-sea corals, etc. Source: HECO Companies. *PSIP Update Report.* December 23, 2016. Book 3. Page H-52.

5 Evaluation of each model relative to State criteria

The assessment of the single-county and multi-county models relative to State's criteria is both qualitative and high-level. Results are subject to refinement as the project proceeds and receives more feedback from stakeholders. The evaluation mechanism is intended as a thought exercise in comparing the single-county with the multi-county models. There are two models only under evaluation, so the Project Team identified the model that meets each State criteria more effectively. Figure 4 shows a summary of the findings.

Figure 4. Summary of evaluation: Utilities' management and operations

Utilities' management and operations	Single-county model (status quo)	Multi-county model
Ability to meet state energy goals	-	*better*
Maximize consumer cost savings	-	*better*
Enable a competitive distribution system	-	*better*
Address conflicts of interest in energy resource planning, delivery, and regulation	*better*	-
Align stakeholder interests	*better*	-

Overall, the multi-county model meets three of the state goals while the current single-county model is better in meeting two of the state goals. If designed and implemented correctly, the multi-county model with inter-island transmission could help achieve the 100% RPS goal faster, maximize consumer cost savings,[15] and enable a competitive distribution system that covers two or more counties. However, specific concerns such as potentially greater conflicts of interests in energy resource planning and delivery among different counties and wider gap among stakeholder interests would need to be addressed.

The two models are evaluated based on their ability to address the following state goals, which are the same criteria used in the evaluation of ownership and regulatory models.

i. meet state energy goals, particularly Hawaii's mandated RPS goal of 100% renewable energy by 2045;

[15] This is based on the assumption that the benefits of the inter-island transmission will be higher than the costs, which are the results of DBEDT's study in 2014 and also result of HECO's study in PSIP 2016.

ii. maximize consumer cost savings;

iii. enable a competitive distribution system in which there is a marketplace for customers and independent agents to trade energy and other evolving services to meet customer and grid needs;

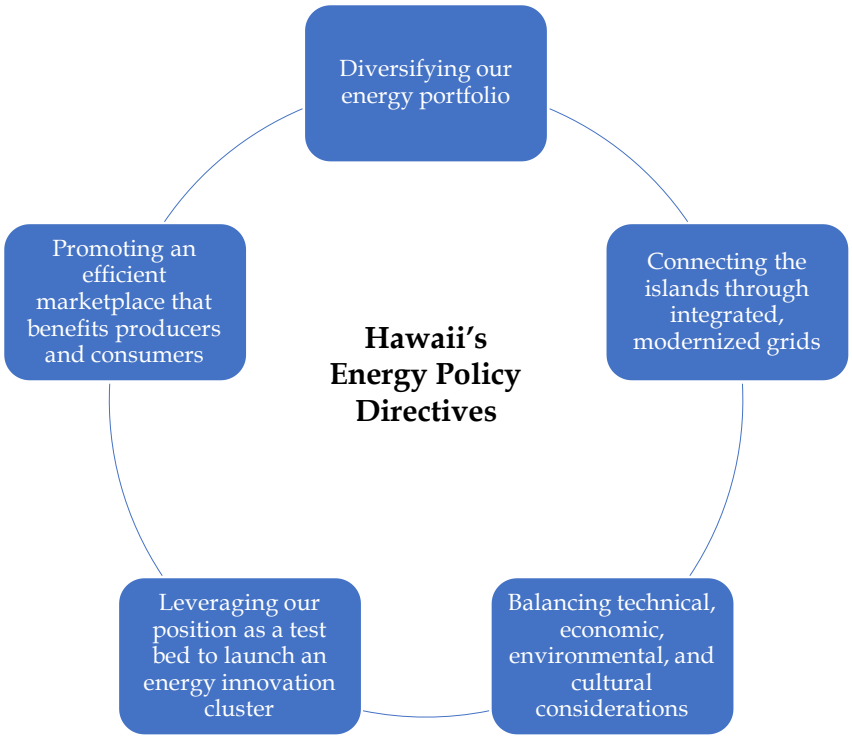
iv. address conflicts of interests in energy resource planning, delivery, and regulation; and

v. align stakeholder interests.[16]

5.1 Ability to meet state energy goals

The Project Team observes that the multi-county model with inter-island transmission lines as meeting more of the state goals than the current single-county model. Figure 5 illustrates Hawaii's energy policy directives.

Figure 5. Hawaii's energy policy directives



Source: HI Rev Stat § 269-92 (2015), Hawaii State Energy Office ("HSEO").

[16] Evaluation of each model relative to "align stakeholder interests" is not required in the scope of work, but the Project Team kept this criterion to make the criteria consistent with those used in evaluating ownership and regulatory models.

Hawaii has one of the most aggressive renewable energy targets in the country. As mentioned above, it aims for its utilities to generate 100% of their electricity from renewable energy by 2045.[17] Although there are other policy directives (Figure 5), for this criterion, the Project Team focused on Hawaii's target to achieve 100% of their electricity from renewable energy by 2045. The other policy directives are covered by the other criteria. For example, "balancing technical, economic, environmental, and cultural considerations" is reflected in criteria (v): align stakeholder interests. Likewise, "promoting an efficient marketplace that benefits producers and consumers" is substantially similar to "enabling a competitive distribution system."

Hawaii's utilities have made substantial progress toward the 100% renewables target under the status quo. All but one of the utilities are ahead of the current intermediate RPS target of 30% by 2020.[18] This indicates that the State's renewable energy goals are currently on-track under the status quo. This state-focused target allows the PUC to push the utilities toward the RPS targets while giving them enough flexibility to design tailored strategies for each county as well as make effective strategic plans collectively.

Changing to the multi-county model with inter-island transmission system can support the achievement of the State's energy targets further. One of the current challenges with increasing renewable generation is how renewable resources could be better utilized in each county. If abundant generation resources in one county could help meet demand in another, it would assist in addressing the concerns of curtailment and resource adequacy at the same time.

Implementation of the Renewable Portfolio Standards goals

As required in House Bill ("HB") 623, each electric utility company in Hawaii should achieve 100% of renewable electrical energy sales by 2045, and "an electric utility company and its electric utility affiliates may aggregate their renewable portfolios to achieve the renewable portfolio standard."* This means that HECO, MECO, and HELCO could combine their renewable energy sales to achieve the RPS targets. Alternatively, the RPS targets could be set up in a way that each electric utility must achieve 100% renewable goal independently for each county.

An ownership change of one utility within HECO Companies could result in this condition. For instance, if MECO and HELCO become independent entities outside of HECO Companies, the new utilities have to meet the 100% renewable goal on their own as they are not affiliated with any parent company. Without collaboration among counties, relying solely on local resources to achieve 100% RPS goal could be challenging for some counties.

* Source: HB 623

[17] HI Rev Stat § 269-92 (2015).

[18] HB623 HD2 SD2 CD1, *Relating to Renewable Standards.* House of Representatives, Twenty-Eight Legislature, 2015. State of Hawaii. Web. Accessed May 10, 2017.

5.2 Maximize consumer cost savings

The multi-county model (with inter-island transmission) is better than the current single-county model in maximizing consumer cost savings.

The City and County of Honolulu is the economic center in the State of Hawaii. Some neighboring islands such as Molokai and Hawaii have greater social and economic challenges than Oahu. Moreover, all the neighboring counties face higher electricity rates than the City and County of Honolulu because of higher fuel costs. As a result, high electricity rate poses more significant challenges to some neighboring counties especially to the low-income class than to Honolulu. During the outreach, many stakeholders in neighboring counties commented that lowering electricity costs is the top priority for them (even more important than achieving the 100% renewable goal).[19]

Admittedly, building inter-island transmission lines will bring significant upfront costs. However, it could bring more benefits to consumers in the long term particularly if designed and implemented effectively. According to the study from DBEDT, an Oahu-Maui grid tie could reduce electricity rates of up to 0.6 cents per kWh while the overall net savings on both islands were estimated to reach $423 million (net present value) in the period 2020 to 2050.[20] Similarly, HECO Companies' E3 Copper-plate Plans noted that the present value benefit of the inter-island cable is $3 billion, as mentioned earlier in the textbox."[21]

5.3 Enable a competitive distribution system

The multi-county model with an inter-island transmission cable could better facilitate the achievement of the state energy goal on enabling a competitive distribution system particularly in terms of utilities' management and operations.

A competitive distribution system is one "in which independent agents can trade and combine evolving services to meet customer and grid needs."[22] This goal requires the evolution of grid operations and services away from the traditional utility business model where the utility has a monopoly over the sale of electricity and other limited services to the customer. If inter-island cables are constructed, the grids that connect two or more counties could create a competitive distribution system. Moreover, the combined generation will be significantly higher than the isolated generation in each island—this could serve as a basis for the centralized competitive distribution system. Therefore, considering the potential of inter-island connection under the multi-county model, the Project Team scored the multi-county model more "favorably" than the single-county model under this criterion.

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[19] For instance, in the County of Hawaii, stakeholders identified reducing rates as the highest priority. Source: deliverable under Task 2.2.5 *Stakeholder Workshop Summary: Regulatory Models*.

[20] HSEO. *Oahu-Maui Grid Tie*. Website. <http://energy.hawaii.gov/renewable-energy/oahu-maui-gridtie>

[21] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 1. Page 3-14.

[22] Hawaii Contract No. 65595. Scope of Services.

5.4 Address conflicts of interest

Conflicts of interest can take place among utility shareholders, ratepayers, regulators, and market participants like independent power producers ("IPPs") and distributed energy resources ("DER") providers in matters of energy resource planning, energy delivery, and regulation. Addressing conflicts of interest requires the participation of local communities and the consideration of county-specific characteristics such as energy resources and culture.

The current single-county model scores "better" because the current single-county model, in theory, would allow more local participation in managing electric systems in each county because the electric system in each county stands alone. As discussed above, some stakeholders are concerned about the imbalanced distribution of costs and benefits in each county if the inter-island transmission lines are constructed under the multi-county model.[23] Box 3 carries a narrative about a transformative experience in a 'standalone' island in Scotland in terms of electricity.

Leadership from the community: Isle of Eigg's electricity transformation

The Isle of Eigg is a small island off the coast of Scotland with approximately 100 residents. The installed capacity is around 250 kW, which is about 18% of the installed capacity (13.7 MW) in Lanai. Prior to 2007, power in the Isle of Eigg was generated at homes and businesses using diesel. Later, the community drove a transformation of the electricity system after recognizing the drawbacks of relying on diesel alone. According to the Rocky Mountain Institute, leadership from the community is a unique feature of the transformation. The residents decided to create an integrated plan for a new connected electricity system rather than create an electrical connection to the mainland grid. Throughout the process, the community was forced to learn by doing, including "applying for grant funding, securing permission to build, finding a contractor to design and build the system, and training local residents on how to operate and repair the renewable microgrid." As a result, a team of local residents are able to maintain the system and "ensure reliable electricity for all community members."

Source: Rocky Mountain Institute and Carbon War Room. *Renewable Microgrids: Profiles from Islands and Remote Communities across the Globe*. November 2015.

5.5 Align stakeholder interests

Aligning stakeholder interests is similar to the previous criterion but with more focus on whether stakeholder interests are aligned rather than whether conflicts can be resolved. The multi-county model is again the less favorable model vis-a-vis alignment of stakeholder interests. This is because the current single-county model enables wider participation of stakeholders from each

[23] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 3. Page H-52.

county in the decision-making process, eventually aligning interests better between stakeholders in the City and County of Honolulu and the neighboring counties. During the stakeholder outreach conducted in each island between June 12th and June 22nd, 2018, several stakeholders raised the issue that the HECO Companies' decision making, as well as some of the PUC's policies, are favoring Oahu.[24]

If the inter-island transmission is built, the City and County of Honolulu as the demand center could be supplied with excess generation from neighboring counties. This could lead to further conflicts of interests with stakeholders in the other counties. As a result, the interests of stakeholders in neighboring counties could be misaligned with that of stakeholders in the City and County of Honolulu.

[24] For more information, please see the deliverable under Task 2.2.5 *Stakeholder Workshop Summary: Regulatory Models*.

6 Additional analysis of ownership and regulatory models[25]

Moreover, the Project Team analyzed how the single-county model and multi-county model would affect the implementation of the ownership and regulatory models that were identified and recommended in Tasks 1.2.5 and 2.2.6. Figure 6 shows a summary of the results.

Figure 6. Comparison of ownership and regulatory models under single-county and multi-county scenarios

Recommended models		Single-county model	Multi-county model
Ownership models	*Cooperative*	Easier to be implemented	Harder to be implemented
	Single Buyer within the utility	Same, because the Single Buyer would be created within the utility	
	Single Buyer outside the utility	Less cost-effective	More cost-effective
Regulatory models	*Outcomes-based PBR*	Same, because the outcomes and reporting will be done by utilities	
	Conventional PBR with HERA Light	Same for the Conventional PBR, because the outcomes and reporting will be done by utilities	
		HERA would be less cost effective	HERA would be more cost effective
	The Hybrid model	DSPP and PBR would not be affected, because they only impact utilities	
		IGO would be less cost effective	IGO would be more cost effective

Note: PBR: performance-based ratemaking, HERA: Hawaii Electricity Reliability Administrator, DSPP: Distributed System Platform Provider, IGO: Integrated Grid Operator.

6.1 Ownership models

Based on the Project Team's analyses, the four most favorable models (when it comes to ownership models) are the cooperative model, status quo, Single Buyer within the utility, and Single Buyer outside the utility. Since the analysis in Section 3 and 4 is based on the status quo, this section focuses on the other three models.

Cooperative

Given the unique features of each county, it would be easier to implement the cooperative model under the single-county model. A cooperative under a single county model would be able to facilitate more local control in the decision-making process—this would allow close alignment of

[25] From the perspective of utilities' management and operations only.

utility activities and goals with community priorities. Moreover, stakeholders within the single county would feel that they have more voice and decision-making power since all the Board members come from the same county.

On the other hand, a cooperative under a multi-county model would not likely provide the same "close alignment" as the single county model because the Board members would have to take the priorities of two or more counties into account. Therefore, the focus would be shared by different counties instead of being enjoyed by one county only. Furthermore, the cooperative model under the multi-county scenario might not even be possible in the state given the farm bill population limits on the definition of "rural." Some sources of co-op funding have specific requirements as to the size of the cooperative. More specifically, the Rural Utilities Service ("RUS") funding[26] is only available for areas with populations smaller than 20,000—this would allow island-wide cooperatives on in Molokai and Lanai only. As discussed in Task 1.2.3, the amended farm bill would not allow the creation of an island-wide cooperative in Oahu or the alteration of analysis in any other island.

Single Buyer within the utility

Under the Single Buyer within the utility model, the Single Buyer is owned by the incumbent utility, but ring-fenced from the functions of the existing utility in terms of legal status, financial accounts, and operations. This includes separated buildings, branding, employees, and information technology systems. Whether it is a single-county or a multi-county model, the single buyer within the utility would not be impacted much because the Single Buyer is within the utility.

Single buyer outside the utility

As for the Single Buyer outside the utility model, the single buyer is not only ring-fenced from the other business entities of the utility but is outside of the utility. It would be more cost-effective to be under a multi-county approach because the interconnection will require one central Single Buyer—tasked to determine the needs of each county and coordinate with the utilities—only.

[26] The RUS has specific loan programs for increasing energy efficiency, renewables, and additional grant programs specifically for high-cost energy areas. For more detailed information, please see Task 1.2.3.

6.2 Regulatory models

With regard to regulatory models, the highest-ranking models are outcomes-based performance-based ratemaking ("PBR"),[27] conventional PBR[28] with Light Hawaii Electricity Reliability Administrator ("HERA"),[29] and Hybrid model, which includes outcomes-based PBR, Distributed System Platform Provider ("DSPP"),[30] and Integrated Grid Operator ("IGO").[31]

Since PBR and DSPP will be implemented within the utilities, the implementation of these regulatory models would not change much whether they are under the single-county or multi-county model.

On the other hand, HERA and IGO would be more cost-effective under the multi-county model. Only one IGO is required once multiple counties are interconnected. Likewise, one HERA entity could do the work for the entire state.

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[27] As discussed in Task 2.1.1 (Introduction to the Regulatory Models), outcomes-based PBR would focus on outcomes related to enhancing customer experience, improving utility performance, achieving public policies and goals, and attaining healthy financial performance. It also features an expanded set of Performance Incentive Mechanisms ("PIMs") with Earning Sharing Mechanism ("ESM") and longer regulatory period, among the other features of this PBR.

[28] Conventional PBR would use an indexation formula and a revenue cap to determine the revenue requirements of the utilities—restricting their ability to increase revenue requirements—but would also have PIMs and a symmetrical ESM and total expenditure approach in treating expenditures.

[29] Under the Light HERA, HERA (the entity) could perform as an ombudsman or appeals body focused on hosting capacity and interconnection. It would have the technical capability to set target timeframes and standard models for the calculation of interconnection costs convened in cases when a customer wants to challenge utility interconnection behavior or lack of hosting capacity transparency. See Task. 2.1.1. for more description of the Light HERA.

[30] The DSPP would be responsible for planning and designing its distribution system so it can integrate DER as a primary means of meeting system needs.

[31] As discussed in Task 2.2.1, the functions of the ISO and independent distribution system operator are combined, and the resulting body is called Independent Grid Operator ("IGO"). Given the smaller size of Hawaii's transmission systems (compared to other jurisdictions), combining these two regulatory models would be more effective and efficient in the Hawaii context.

7 Appendix A: Scope of work to which this deliverable responds

Task 3.1.3 Assessing the pros and cons of managing Hawaii's electricity sector with each county operating independently as compared to a multi-county model.

CONTRACTOR shall include an analysis of the relative advantages and disadvantages of each county operating independently and collectively as a part of a multi-county model which may include the ownership of electric utilities in two or more counties. CONTRACTOR shall evaluate the potential for each model to 1) achieve State energy goals; 2) maximize consumer cost savings; 3) enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs; and 4) eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation.

DELIVERABLE FOR TASK 3.1.3. CONTRACTOR shall provide its conclusions and all work related to assessing the pros and cons of managing Hawaii's electricity sector with each county operating independently as compared to a multi-county model. CONTRACTOR shall consider the cost savings and additional costs that might be entailed in a multi-county model to assess the impact on consumer costs. CONTRACTOR shall consider the benefits that a multi-county model may offer achieving state energy goals as compared to the costs. CONTRACTOR shall assess whether there is any impact from a single county or multi-county model to enabling a competitive distribution system or reducing conflicts of interest in energy planning, delivery, and regulation. CONTRACTOR shall provide a written summary of the findings in MS Word and Power Point. CONTRACTOR shall submit deliverable for TASK 3.1.3 to the STATE for approval.

8 Appendix B: List of works consulted

DBEDT. *Initial Public Comments in Response to Hawaii PUC* Order No. 31356 (Docket No. 2013-0169). HECO Companies. 2016 PSIP.

DOE. "Renewable Portfolio Standard." Web. < https://www.energy.gov/savings/renewable-portfolio-standard-4>. Access date: August 21, 2018.

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