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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<th>Acronym</th>
<th>Full Form</th>
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<tbody>
<tr>
<td>AGDC</td>
<td>Alaska Gasline Development Corporation</td>
</tr>
<tr>
<td>APPA</td>
<td>American Public Power Association</td>
</tr>
<tr>
<td>ASB</td>
<td>American Savings Bank</td>
</tr>
<tr>
<td>B Corp</td>
<td>Benefit corporations</td>
</tr>
<tr>
<td>BESS</td>
<td>Battery energy storage system</td>
</tr>
<tr>
<td>CBRE</td>
<td>Community-Based Renewable Energy</td>
</tr>
<tr>
<td>CFC</td>
<td>Cooperative Finance Corporation</td>
</tr>
<tr>
<td>Co-ops</td>
<td>Cooperative utilities</td>
</tr>
<tr>
<td>DBEDT</td>
<td>Hawaii Department of Business, Economic Development and Tourism</td>
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<tr>
<td>DER</td>
<td>Distributed Energy Resource</td>
</tr>
<tr>
<td>DSP</td>
<td>Distribution System Platform</td>
</tr>
<tr>
<td>DUOS</td>
<td>Distribution Use of System</td>
</tr>
<tr>
<td>EIA</td>
<td>US Energy Information Administration</td>
</tr>
<tr>
<td>EMA</td>
<td>Energy Market Authority</td>
</tr>
<tr>
<td>G&amp;T</td>
<td>Generation and Transmission</td>
</tr>
<tr>
<td>GMP</td>
<td>Green Mountain Power</td>
</tr>
<tr>
<td>HCA</td>
<td>Historical Cost Accounting</td>
</tr>
<tr>
<td>HECO</td>
<td>Hawaiian Electric Company, Inc.</td>
</tr>
<tr>
<td>HEI</td>
<td>Hawaiian Electric Industries, Inc.</td>
</tr>
<tr>
<td>HELCO</td>
<td>Hawaii Electric Light Company, Inc.</td>
</tr>
<tr>
<td>HERA</td>
<td>Hawaii Electricity Reliability Administrator</td>
</tr>
<tr>
<td>HES</td>
<td>Hermiston Energy Services</td>
</tr>
<tr>
<td>HSEO</td>
<td>Hawaii State Energy Office</td>
</tr>
<tr>
<td>IDER</td>
<td>Integrated DER</td>
</tr>
<tr>
<td>IESCO</td>
<td>Independent Electricity System Operator</td>
</tr>
<tr>
<td>IOU</td>
<td>Investor-Owned Utility</td>
</tr>
<tr>
<td>IPP</td>
<td>Independent Power Producer</td>
</tr>
<tr>
<td>IRP</td>
<td>Integrated Resource Plan</td>
</tr>
<tr>
<td>ITC</td>
<td>Investment Tax Credits</td>
</tr>
<tr>
<td>KIUC</td>
<td>Kauai Island Utility Cooperative</td>
</tr>
<tr>
<td>KOGAS</td>
<td>Korea Gas Corporation</td>
</tr>
</tbody>
</table>
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.

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

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
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.

---

\(^2\) 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.

<table>
<thead>
<tr>
<th>Form</th>
<th>Local Ownership?</th>
<th>For profit?</th>
<th>Regulator</th>
<th>Management time horizon</th>
</tr>
</thead>
<tbody>
<tr>
<td>IOU</td>
<td>limited</td>
<td>yes</td>
<td>PUC</td>
<td>short</td>
</tr>
<tr>
<td>New parent under IOU</td>
<td>depends on parent</td>
<td>parent may or may not be</td>
<td>PUC</td>
<td>depends on parent</td>
</tr>
<tr>
<td>Co-op</td>
<td>yes</td>
<td>returns profits to members</td>
<td>self*</td>
<td>long</td>
</tr>
<tr>
<td>Muni</td>
<td>yes</td>
<td>profits partly fund city budget</td>
<td>city council</td>
<td>medium</td>
</tr>
<tr>
<td>Hybrid (Government majority)</td>
<td>yes</td>
<td>profits partly fund state budget</td>
<td>PUC</td>
<td>long</td>
</tr>
<tr>
<td>Integrated DER</td>
<td>mixed</td>
<td>yes</td>
<td>PUC</td>
<td>medium</td>
</tr>
<tr>
<td>Single buyer</td>
<td>mixed</td>
<td>no for single buyer itself</td>
<td>PUC</td>
<td>long</td>
</tr>
<tr>
<td>Grid defection</td>
<td>mixed</td>
<td>yes</td>
<td>building codes</td>
<td>long</td>
</tr>
</tbody>
</table>

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.*

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

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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. 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

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**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”).

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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.

<table>
<thead>
<tr>
<th>Figure 3. Co-op principles</th>
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<tbody>
<tr>
<td><strong>Open and voluntary membership</strong></td>
</tr>
<tr>
<td>• Membership is open to all who can reasonably use its services and accept the responsibilities of membership</td>
</tr>
<tr>
<td><strong>Democratic membership control</strong></td>
</tr>
<tr>
<td>• It is a democratic organization controlled by their members, who actively participate in setting policies and making decisions</td>
</tr>
<tr>
<td><strong>Members’ economic participation</strong></td>
</tr>
<tr>
<td>• Members contribute equitably to the capital of their cooperative. Part of the capital remains the common property of the cooperative while the excess of operating revenues are allocated among members</td>
</tr>
<tr>
<td><strong>Autonomy and independence</strong></td>
</tr>
<tr>
<td>• Cooperatives are autonomous self-help organizations controlled by their members</td>
</tr>
<tr>
<td><strong>Education, training, and information</strong></td>
</tr>
<tr>
<td>• Education and training help members and employees effectively contribute to the development of their cooperatives</td>
</tr>
<tr>
<td><strong>Cooperation among cooperatives</strong></td>
</tr>
<tr>
<td>• Working together improves services, bolster local economies, and deal more effectively with social and community needs</td>
</tr>
</tbody>
</table>

*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


\(^{16}\) 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.\textsuperscript{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”),\textsuperscript{18} National Rural Utilities Cooperative Finance Cooperation (“CFC”), and the National Cooperative Services Corporation (“NCSC”),\textsuperscript{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.

\textsuperscript{17} Ibid.

\textsuperscript{18} An agency of the US Department of Agriculture.

\textsuperscript{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.

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. 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):*

<table>
<thead>
<tr>
<th>Companies</th>
<th>Number of customers</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO Companies</td>
<td>460,000</td>
</tr>
<tr>
<td>Austin Energy</td>
<td>452,898</td>
</tr>
<tr>
<td>Jacksonville Electric Authority</td>
<td>445,823</td>
</tr>
<tr>
<td>Seattle City Light</td>
<td>422,809</td>
</tr>
<tr>
<td>Memphis Light Gas &amp; Water</td>
<td>410,679</td>
</tr>
</tbody>
</table>

*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

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.
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. 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

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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.\textsuperscript{22} HERA could also take on the role of system operator as envisioned in the IDER model.\textsuperscript{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.

\begin{center}
\textbf{Ontario Power Authority/ Independent Electricity System Operator}
\end{center}

On January 1, 2015, the Ontario Power Authority (“OPA”) and the Independent Electricity System Operator (“IESO”) were merged through amendments to the \textit{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.

\textit{Source: IESO.}

\textsuperscript{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.

\textsuperscript{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; while the phenomenon may not be imminent, it is likely closer in Hawaii than it is on the mainland.

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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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.](image)

### 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. 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
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

<table>
<thead>
<tr>
<th>Utility motivation</th>
<th>IOU</th>
<th>New parent</th>
<th>Co-op</th>
<th>Muni</th>
<th>Hybrid</th>
<th>IDER</th>
<th>Single Buyer</th>
<th>Grid defection/disperse ownership</th>
</tr>
</thead>
<tbody>
<tr>
<td>• More bias towards generation</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>• More bias towards wires</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
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<tr>
<td>• Generation and transmission neutral</td>
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<td></td>
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<td>X</td>
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<td>Role of regulator</td>
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<tr>
<td>• Regulates reliability standards</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>• Regulates rates</td>
<td>X</td>
<td>X</td>
<td>X*</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>• Ensures equality of access</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
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<tr>
<td>• Ensures effectiveness of integration</td>
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<tr>
<td>• Ensures fairness in procurement process</td>
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<tr>
<td>Generation remuneration</td>
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<tr>
<td>• Utility continues to be under ratebase</td>
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<td></td>
<td>X</td>
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<tr>
<td>• Another approach to rate design might need to be explored</td>
<td>X</td>
<td>X</td>
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<tr>
<td>Planning</td>
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<td></td>
</tr>
<tr>
<td>• Utility is responsible for generation and grid planning</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>• Utility is responsible for grid planning</td>
<td>X</td>
<td></td>
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<td></td>
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<tr>
<td>• Regulator is responsible for grid planning</td>
<td>X</td>
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<td></td>
<td></td>
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<tr>
<td>Taxation</td>
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<td></td>
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<tr>
<td>• Federal tax-exempt</td>
<td>X</td>
<td>X</td>
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<td>X</td>
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<tr>
<td>• State tax-exempt</td>
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<td>X</td>
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<tr>
<td>• Tax-exempt on debt financing</td>
<td></td>
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<td>X</td>
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<tr>
<td>Fund mobilization</td>
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<td></td>
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<tr>
<td>• Greater access to capital</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>• Retained earnings are primary source of equity</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
</tr>
</tbody>
</table>

* 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,\(^2^8\) 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

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\(^2^8\) 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: $3.7 billion

*Calculated using:
- Current stock price: $32.02 per share
- Number of shares: 108,750,455 shares
- Assumed premium: 5%

Estimated Cost of ASB: $1.3 billion

*Calculated using:
- Estimated Market Price Per Share of ASB only: $12.05
- ASB’s Book Value per Share: $5.48
- Average Price to Book Ratio of similar banks: 2.20

Estimated Cost of HECO Companies: $2.1 billion

Amount offered by NextEra: $4.3 billion (in 2014)

Note:
- This is just a back of the envelope calculation
- This assumes buying the HEI entirely, including the American Savings Bank ("ASB").
- LEI does not foresee KIUC being acquired by an IOU and therefore estimated cost of acquisition is not estimated.
- As of July 17, 2017
- Assuming debt unchanged at the holding company level, the net debt (as of latest filing) is $346.25 million
- The estimated cost of ASB is estimated by multiplying the total number of HEI shares by the estimated ASB market price per share.
- Estimated cost of the HECO Companies is calculated by subtracting the Cost of ASB from the Cost of HEI.
- 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.
- 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.
- 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 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
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).

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

<table>
<thead>
<tr>
<th>Event</th>
<th>Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>PacifiCorp closes local customer service center</td>
<td>1996</td>
</tr>
<tr>
<td>City of Hermiston votes in favor of municipalization</td>
<td>1998</td>
</tr>
<tr>
<td>City of Hermiston conducts feasibility assessments</td>
<td>1998 - 2001</td>
</tr>
<tr>
<td>Hermiston Energy Services established as local municipal utility</td>
<td>2001</td>
</tr>
</tbody>
</table>

Source: Public Utility Commission of Oregon, APPA.
✓ 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.


31 Ibid; Hawaii House Bill 416 (January 26, 2015), and House Bill 1494 (December 17, 2015).
Figure 5. Hawaii’s energy policy directives


Figure 6. Position of each model in the scale in terms of its ability to meet state goals

<table>
<thead>
<tr>
<th>Least favorable</th>
<th>Most favorable</th>
</tr>
</thead>
<tbody>
<tr>
<td>Muni</td>
<td>IOU</td>
</tr>
<tr>
<td>Government</td>
<td>New Parent</td>
</tr>
<tr>
<td>Grid majority</td>
<td>Single Buyer</td>
</tr>
<tr>
<td>defection</td>
<td>Integrated DER</td>
</tr>
<tr>
<td>Co-op</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
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<tr>
<td></td>
<td></td>
</tr>
</tbody>
</table>

4.2 Maximize consumer cost savings

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

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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**

<table>
<thead>
<tr>
<th>Least favorable</th>
<th>Most favorable</th>
</tr>
</thead>
<tbody>
<tr>
<td>IOU, Grid defection, Muni, Government majority, Integrated DER, New Parent, Co-op, Single Buyer</td>
<td></td>
</tr>
</tbody>
</table>

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**

<table>
<thead>
<tr>
<th>Least favorable</th>
<th>Most favorable</th>
</tr>
</thead>
<tbody>
<tr>
<td>Muni, Government majority, Co-op, IOU, New Parent, Single Buyer, Grid defection, Integrated DER</td>
<td></td>
</tr>
</tbody>
</table>

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.
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.

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.
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\textsuperscript{33} and KIUC’s publicly available information (such as the KIUC Strategic Plan Update 2016-2030\textsuperscript{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.\textsuperscript{35} In addition, HECO Companies filed a grid modernization plan in August 2017, which is estimated to cost about $205 million over six years.\textsuperscript{36} By 2045, Hawaii electric utilities plan to invest between $15 and $21 billion to add over 2,450 MW of new renewable capacity.\textsuperscript{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.

\textsuperscript{33} PUC accepted the PSIP on July 14, 2017.

\textsuperscript{34} Approved by KIUC’s Board of Directors on January 31, 2017.


\textsuperscript{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. \textit{PSIP Update Report}. December 23, 2016. Book 1, Chapter 5.
Figure 12. State’s installed capacity by fuel type and county (2017)

By fuel type

- Oil: 56%
- Diesel: 14%
- Biomass/biodiesel/refuse: 7%
- Coal: 7%
- Wind: 7%
- Gas: 1%
- Hydro: 1%
- Geothermal: 1%
- Solar: 6%

By county

- Honolulu (68%)
- Kauai (7%)
- Maui (13%)
- Hawaii (12%)

Figure 13. Installed capacity by county (2017)

Honolulu County

- Installed capacity: 1,876 MW
- Oil: 71.1%
- Diesel: 39.86%
- Wind: 9.35%
- Hydro: 6.31%
- Geothermal: 11.47%

Maui County

- Installed capacity: 355 MW
- Oil: 18.6%
- Diesel: 58.6%
- Wind: 20.3%
- Solar: 4.3%
- Hydro: 0.1%

Hawaii County

- Installed capacity: 331 MW
- Oil: 33.01%
- Diesel: 39.86%
- Wind: 9.35%
- Solar: 2.3%
- Hydro: 6.31%

Kauai County

- Installed capacity: 208 MW
- Oil: 25.36%
- Diesel: 21.05%
- Gas: 32.06%
- Solar: 2.3%
- Biomass/biodiesel/refuse: 3.35%

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](http://kauai.coopwebbuilder.com/sites/kauai.coopwebbuilder.com/files/schedule_q_eff_092012.pdf)

**Figure 14. Hawaii’s electric service territories**

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).


\(^{39}\) This assumes that those plants that are currently not reported to be retired will be converted to biomass/biodiesel.
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. The updated PSIP was submitted to the PUC on December 23, 2016.

(Docket 2014-0183), which the PUC accepted on July 14, 2017, directing HECO to implement the near-term plans. Previously, the PUC had rejected the first version of the PSIP from August 2014, and rendered moot the second version from April 2016 when it dismissed the utilities’ merger with NextEra Energy.

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, grid-scale wind, and FIT);
- about 137 MWh of storage; and
- about 115 MW of demand response program resources.

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. Figure 17, Figure 18, and Figure 19 show the planned new entry and retirements in Honolulu, Maui, and Hawaii counties.

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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

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\(^{53}\) 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].”


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.\footnote{KIUC. 2017 Capital Improvements Program for Ensuing Five Years. December 27, 2016.}

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.\footnote{“Tesla built a huge solar energy plant on the island of Kauai.” The Verge. March 8, 2017.} 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.”\footnote{“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>}

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.\footnote{“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/>} 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**

<table>
<thead>
<tr>
<th>Plant Name</th>
<th>Fuel type</th>
<th>Capacity (MW)</th>
<th>Proposed Online Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>AES Lawai</td>
<td>Solar</td>
<td>28</td>
<td>2018</td>
</tr>
<tr>
<td>Gay &amp; Robinson, Olokele</td>
<td>Hydro</td>
<td>6</td>
<td>2019</td>
</tr>
<tr>
<td>Pacific Missile Range Facility</td>
<td>Solar plus Storage</td>
<td>44</td>
<td>2020</td>
</tr>
<tr>
<td>Pu’u Opa Pumped Storage</td>
<td>Hydro pumped storage</td>
<td>25</td>
<td>2023</td>
</tr>
<tr>
<td><strong>SUM</strong></td>
<td></td>
<td><strong>103</strong></td>
<td></td>
</tr>
</tbody>
</table>

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%. 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.

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**

<table>
<thead>
<tr>
<th>Island and County</th>
<th>Forecast RPS (%)</th>
<th>Forecasted Renewables (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Molokai Island (Maui County)</td>
<td>142%</td>
<td>8.50</td>
</tr>
<tr>
<td>Hawaii Island (Hawaii County)</td>
<td>80%</td>
<td>235.30</td>
</tr>
<tr>
<td>Maui Island (Maui County)</td>
<td>63%</td>
<td>284.00</td>
</tr>
<tr>
<td>Lanai Island (Maui County)</td>
<td>59%</td>
<td>6.70</td>
</tr>
<tr>
<td>Oahu Island (Honolulu County)</td>
<td>45%</td>
<td>1,299.00</td>
</tr>
</tbody>
</table>


**Figure 24. State of Hawaii’s RPS mandates and HECO’s anticipated target achievement**


---


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.\(^2\) 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.\(^3\)

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

---


• 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**

<table>
<thead>
<tr>
<th>Capital expenditures (nominal, 2017-2021, $b)</th>
<th>HECO</th>
<th>MECO</th>
<th>HELCO</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Post-April PSIP Plan</td>
<td>$1.72</td>
<td>$1.19</td>
<td>$0.47</td>
<td>$3.38</td>
</tr>
<tr>
<td>E3 Plan</td>
<td>$1.62</td>
<td>$1.14</td>
<td>$0.42</td>
<td>$3.17</td>
</tr>
<tr>
<td>E3 Plan with LNG</td>
<td>$1.84</td>
<td>$1.22</td>
<td>$0.47</td>
<td>$3.53</td>
</tr>
<tr>
<td>E3 Plan with Generation Modernization</td>
<td>$1.70</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>E3 Plan with LNG and Generation Modernization</td>
<td>$1.93</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

| Min                                          | $1.62   | $1.14   | $0.42   | $3.17  |
| Max                                          | $1.93   | $1.22   | $0.47   | $3.53  |

<table>
<thead>
<tr>
<th>Capital expenditures (nominal, 2017-2045, $b)</th>
<th>HECO</th>
<th>MECO</th>
<th>HELCO</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Post-April PSIP Plan</td>
<td>$9.41</td>
<td>$3.30</td>
<td>$2.15</td>
<td>$14.86</td>
</tr>
<tr>
<td>E3 Plan</td>
<td>$13.92</td>
<td>$3.66</td>
<td>$2.55</td>
<td>$20.13</td>
</tr>
<tr>
<td>E3 Plan with LNG</td>
<td>$14.05</td>
<td>$3.92</td>
<td>$2.57</td>
<td>$20.54</td>
</tr>
<tr>
<td>E3 Plan with Generation Modernization</td>
<td>$13.93</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>E3 Plan with LNG and Generation Modernization</td>
<td>$13.72</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

| 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**

<table>
<thead>
<tr>
<th>Revenue Requirement (NPV, 2017-2045, $b)</th>
<th>HECO</th>
<th>MECO</th>
<th>HELCO</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Post-April PSIP Plan</td>
<td>$26.53</td>
<td>$5.29</td>
<td>$5.04</td>
<td>$36.85</td>
</tr>
<tr>
<td>E3 Plan</td>
<td>$26.29</td>
<td>$5.05</td>
<td>$4.74</td>
<td>$36.09</td>
</tr>
<tr>
<td>E3 Plan with LNG</td>
<td>$24.94</td>
<td>$4.98</td>
<td>$4.84</td>
<td>$34.76</td>
</tr>
<tr>
<td>E3 Plan with Generation Modernization</td>
<td>$26.56</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>E3 Plan with LNG and Generation Modernization</td>
<td>$25.74</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

| 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.” 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:

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.

---


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,” 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 prudence 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.

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;
- accommodate large amounts of variable renewable generation on Oahu over 10 to 15 years; and
- address aging infrastructure and reliability issues on Hawaii Island.

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 uncertainty around the cable permitting, feasibility, and timing.” The PSIP analysis also determined that the interisland transmission scenario created an unrealistic result, where renewable energy additions on
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. 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.”

As for KIUC, several transmission projects are planned on the Kauai Island, which collectively are estimated to cost nearly $37 million:

- 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, 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;”
- certain assumptions were “forced” into the models, and this may have disproportionately favored utility-owned resources;

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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).

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.


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.
Appendix B: List of works consulted


Hawaii DBEDT. Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).


House Bill No. 1700 relating to the State Budget.


KIUC. *Kauai Consolidated Financial Statements (December 31, 2016 and 2015).*


“Tesla built a huge solar energy plant on the island of Kauai”. *The Verge.* March 8, 2017.


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 maps1 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
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, was 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 listed in Figure 1.

![Figure 1. State’s key criteria](source)

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).


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.  

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

Hawaii has a total capacity of 3,427 MW as of September 2017. 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. 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.

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 PSIP12), 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 Current13, 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.

9 Analysis of transmission system and substations is based on data from Velocity Suite and Annual Financial Reports (“AFR”) for Electric Utilities 2016.


11 U.S. Census Bureau, Population Division.


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. These are expected to be online in 2018 and 2020, respectively. In addition to these resources, 21.5 MW


of biomass plant developed by Hu Honua Bioenergy, LLC is anticipated to be operational by the end of 2018. 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.

---


3.3 Hawaii County substation facilities

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\textsuperscript{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**

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\textsuperscript{20}. A portion of Molokai comprises Kalawao County, but it is taken into consideration as part of Maui County in this section.

\textsuperscript{19} The voltage, in kilovolts, of the largest feature from the Electric Transmission Lines that connects to the feature.

\textsuperscript{20} U.S. Census Bureau, Population Division.
Maui County’s total net capacity as of September 2017 is about 466 MW including 119 MW of DG. 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. 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.

---


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 5.74 MW grid-scale PV (2017), 1 MW grid-scale PV (2018, CBRE), 2 MW 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


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.

Figure 9. Maui County transmission facilities

Source: Created the map using the Energy Velocity Suite

4.3 Maui County substation facilities

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 MVA.


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\textsuperscript{27} is the predominant operating voltage of substations in the county as shown in Figure 10 below.

\textbf{Figure 10. Maui County substation facilities}

\textit{Source: Created the map using the Energy Velocity Suite}

\textsuperscript{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). Downtown Honolulu is the center of business and government for the State of Hawaii.

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. HECO is the largest generation player in the county, owning about 51% of the net capacity.

Source: Created the map using the Energy Velocity Suite

---

28 U.S. Census Bureau, Population Division.

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. The remaining capacity comes mostly from wind, solar and biofuels.

More than 692 MW of proposed generating resources are planned to be online in the next five years (from 2017 to 2021). These include: 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

Source: Created the map using the Energy Velocity Suite


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


5.3 City and County of Honolulu substation facilities

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\(^3\) 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](image)

Source: Created the map using the Energy Velocity Suite

---

\(^3\) 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.

\(^3\) 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**

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.

---

\(^{36}\) U.S. Census Bureau, Population Division.


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

---


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

<table>
<thead>
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<th>Legend</th>
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<tr>
<td>Electric Transmission Lines</td>
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</table>

#### Figure 17. Kauai County transmission facilities

Source: Created the map using the Energy Velocity Suite

### 6.3 Kauai County substation facilities43

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.


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.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{kauai_substations.png}
\caption{Kauai County substation facilities}
\end{figure}

\begin{center}
\textit{Source: Created the map using the Energy Velocity Suite}
\end{center}

\textsuperscript{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.
Appendix B: List of works consulted


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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<th>Acronym</th>
<th>Description</th>
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<tr>
<td>AFR</td>
<td>Annual Financial Reports for Electric Utilities</td>
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<td>CEMS</td>
<td>Continuous Emission Monitoring Systems - United States Environmental Protection Agency</td>
</tr>
<tr>
<td>DBEDT</td>
<td>Hawaii Department of Business, Economic Development and Tourism</td>
</tr>
<tr>
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<td>Distributed generation photovoltaic</td>
</tr>
<tr>
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<td>US Energy Information Association</td>
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<td>North American Electric Reliability Corporation</td>
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<tr>
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<td>Power System Improvement Plan</td>
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<td>USGS</td>
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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, was 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 listed in Figure 1.

Figure 1. State’s key criteria for evaluating the models

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: 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).


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**

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<thead>
<tr>
<th>Asset Category</th>
<th>Tab Contents</th>
<th>Sources</th>
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<td>Generation asset data</td>
<td>Table 1.1 Hawaii County Gen</td>
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<td>Table 1.2 Maui County Gen</td>
<td>Contracts, KIUC website, KIUC 2017 Capital Improvements</td>
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<td>Table 1.3 Honolulu County Gen</td>
<td>Program for Ensuing Five Years, SNL Power Plant Profile</td>
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<td>Table 1.4 Kauai County Gen</td>
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<td>Transmission asset data</td>
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<td>Table 2.2 Maui County Transmission</td>
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<td>Table 2.3 Honolulu County Transmission</td>
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<td>Substation asset data</td>
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<td>Table 3.2 Maui County Substation</td>
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<td>Table 3.3 Honolulu County Substation</td>
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<td>Table 3.4 Kauai County Substation</td>
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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
- US Energy Information Association (“EIA”)
- SNL Financial – is a paid third-party database provider and is part of S&P Global Market Intelligence. 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. 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 their website at https://marketintelligence.spglobal.com/about-us/about-us.html.

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.
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**

*Capacity by generation owners*

<table>
<thead>
<tr>
<th>Generation Owner</th>
<th>Capacity Share</th>
</tr>
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<tbody>
<tr>
<td>Hawaiian Electric Industries</td>
<td>50%</td>
</tr>
<tr>
<td>City &amp; County of Honolulu</td>
<td>33%</td>
</tr>
<tr>
<td>AES</td>
<td>5%</td>
</tr>
<tr>
<td>KIUC</td>
<td>4%</td>
</tr>
<tr>
<td>PSEG</td>
<td>3%</td>
</tr>
<tr>
<td>Harrbert Management</td>
<td>3%</td>
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**Figure 7. Installed capacity, by county and generation owner**

**Hawaii**

<table>
<thead>
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<th>Generation Owner</th>
<th>Capacity Share</th>
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<tbody>
<tr>
<td>Hawaiian Electric Industries</td>
<td>27%</td>
</tr>
<tr>
<td>EPG</td>
<td>2%</td>
</tr>
<tr>
<td>Apolie Energy Corp</td>
<td>3%</td>
</tr>
<tr>
<td>Berkshire Hathaway</td>
<td>5%</td>
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<tr>
<td>Northof Capital</td>
<td>3%</td>
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<tr>
<td>Oreant Technologies</td>
<td>5%</td>
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<tr>
<td>Other IPPs</td>
<td>25%</td>
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**Honolulu**

<table>
<thead>
<tr>
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<th>Capacity Share</th>
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<tbody>
<tr>
<td>Hawaiian Electric Industries</td>
<td>31%</td>
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<td>PSEG</td>
<td>4%</td>
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<td>Harbert Management</td>
<td>4%</td>
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<tr>
<td>AES</td>
<td>4%</td>
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<tr>
<td>DE Shaw &amp; Co</td>
<td>3%</td>
</tr>
<tr>
<td>Other IPPs</td>
<td>22%</td>
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**Kauai**

<table>
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<th>Generation Owner</th>
<th>Capacity Share</th>
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<tr>
<td>KIUC</td>
<td>71%</td>
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<td>McBryde</td>
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<td>Green Energy Team</td>
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<tr>
<td>Tesla</td>
<td>7%</td>
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<td>Other IPPs</td>
<td>13%</td>
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**Maui**

<table>
<thead>
<tr>
<th>Generation Owner</th>
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<tr>
<td>Hawaiian Electric Industries</td>
<td>59%</td>
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<td>AES</td>
<td>2%</td>
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<td>NRG Energy</td>
<td>4%</td>
</tr>
<tr>
<td>TerraFormPower</td>
<td>7%</td>
</tr>
<tr>
<td>Other IPPs</td>
<td>26%</td>
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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.

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. Figure 11 shows the State’s transmission miles by county. The capacity of the transmission lines across all the four counties ranges from 13.8 kV – 138 kV 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**

![Bar chart showing transmission miles by county.](image)

*Source: HECO Companies’ FERC Form 1 filings and KIUC website*

**Figure 12. Hawaii State number of substations (transmission and distribution), by county**

![Bar chart showing number of substations by county.](image)

*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

Capacity by generation players

- Hawaiian Electric Industries: 51%
- DE Shaw & Co: 3%
- AES: 8%
- Harbert Management: 4%
- PSEG: 4%
- City & County of Honolulu: 3%
- Others: 27%

Capacity by fuel type

- Oil: 56%
- DGPV: 21%
- Coal: 8%
- Solar (utility): 3%
- Refuse: 3%
- Wind: 4%
- Biodiesel: 5%

Age of oil-fired plants

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.
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


KIUC. *Energy Information*. Website. Access date: July 26, 2017. [http://website.kiuc.coop/content/energy-information](http://website.kiuc.coop/content/energy-information)


S&P Global Market Intelligence. Access date: July – August 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

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<thead>
<tr>
<th>Acronym</th>
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<tr>
<td>ADMS</td>
<td>Advanced Distribution Management System</td>
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<td>AFR</td>
<td>Annual Financial Reports for Electric Utilities</td>
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<td>AGC</td>
<td>Automatic Generation Control</td>
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<td>DBEDT</td>
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<td>DER</td>
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<td>Distributed Energy Resource Management System</td>
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<td>Distribution Management System</td>
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<td>Distribution Operations Center</td>
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<td>DSIP</td>
<td>Distributed System Implementation Plan</td>
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<td>DSP</td>
<td>Distributed System Platform</td>
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<td>FCI</td>
<td>Faulted Circuit Indicators</td>
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<td>GIS</td>
<td>Geographic Information System</td>
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<td>Hawaiian Electric Company</td>
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<td>Hawaiian Electric Industries Inc.</td>
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<td>HELCO</td>
<td>Hawaii Electric Light Company</td>
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<td>IDER</td>
<td>Integrated Distributed Energy Resources</td>
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<td>Independent System Operator</td>
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<td>JU</td>
<td>Joint Utilities of New York</td>
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<td>Kauai Island Utility Cooperative</td>
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<td>kV</td>
<td>Kilovolt</td>
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<tr>
<td>MDMS</td>
<td>Meter Data Management System</td>
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<td>TNB</td>
<td>Tenaga Nasional Berhad</td>
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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 1.1.4 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. 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.

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 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.
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, 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 criteria5 listed in Figure 2.

![Figure 2. State’s key criteria in evaluating the models](source)

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).


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.  

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.

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.

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.
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. HELCO has deployed Supervisory Control and Data Acquisition (“SCADA”) systems at 78% of its distribution substation transformers. 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

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compliance, including load duration. Dispatchable resources are placed under Automatic Generation Control (“AGC”). The order of preference for dispatch is shown in Figure 5. 

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. 

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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
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.\textsuperscript{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.\textsuperscript{16} HECO has deployed SCADA systems at 49% of its distribution substation transformers.\textsuperscript{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.\textsuperscript{18} It has considered increased exemption from PUC regulation for greater operational flexibility.\textsuperscript{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.\textsuperscript{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.\textsuperscript{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


\textsuperscript{16} AFR 2016. Additional detail in the Excel spreadsheet deliverable for Task 1.1.3.

\textsuperscript{17} \textit{Modernizing Hawaii’s Grid for Our Customers}. August 29, 2017. page 85.

\textsuperscript{18} KIUC website.


\textsuperscript{21} Kauai Island Utility Cooperative. \textit{2016 Annual Report}. 

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growing rapidly. The utility manages dispatch with an EMS/SCADA system, which it proposed to upgrade in 2018.\textsuperscript{22}

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. 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.

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. 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


24 KIUC website.


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**

<table>
<thead>
<tr>
<th>Utility</th>
<th>Island</th>
<th>DG-PV (MW)</th>
<th>FIT (MW)</th>
<th>DR (MW)</th>
<th>Grid-scale PV (MW)</th>
<th>Grid-scale wind (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO</td>
<td>Oahu</td>
<td>255.1</td>
<td>23.8</td>
<td>88.8</td>
<td>352.2</td>
<td>64.0</td>
</tr>
<tr>
<td>MECO</td>
<td>Maui</td>
<td>38.4</td>
<td>1.0</td>
<td>14.7</td>
<td>6.7</td>
<td>62.0</td>
</tr>
<tr>
<td>MECO</td>
<td>Molokai</td>
<td>1.4</td>
<td>0.0</td>
<td>0.3</td>
<td>0.0</td>
<td>5.0</td>
</tr>
<tr>
<td>MECO</td>
<td>Lanai</td>
<td>0.7</td>
<td>0.0</td>
<td>0.3</td>
<td>0.0</td>
<td>4.0</td>
</tr>
<tr>
<td>HELCO</td>
<td>Hawaii</td>
<td>30.3</td>
<td>5.7</td>
<td>10.6</td>
<td>1.0</td>
<td>22.0</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>325.9</strong></td>
<td><strong>30.5</strong></td>
<td><strong>114.7</strong></td>
<td><strong>359.9</strong></td>
<td><strong>157.0</strong></td>
</tr>
</tbody>
</table>


**Figure 8. PSIP Projections - DERs and DRs**

<table>
<thead>
<tr>
<th>December 2016 PSIP Projections</th>
<th>2017-2021</th>
<th>2022-2045</th>
</tr>
</thead>
<tbody>
<tr>
<td>New DG-PV</td>
<td>326 MW</td>
<td>2,086 MW</td>
</tr>
<tr>
<td>New Customer Self-Supply (CSS) Energy Storage</td>
<td>89 MWh</td>
<td>1,057 MWh</td>
</tr>
<tr>
<td>New Demand Response Capacity</td>
<td>115 MW</td>
<td>442 MW</td>
</tr>
<tr>
<td>New Demand Response Energy Storage</td>
<td>104 MWh</td>
<td>1,608 MWh</td>
</tr>
</tbody>
</table>


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. 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.


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.\textsuperscript{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.\textsuperscript{31} It also intends to spend over $52 million in recurring and $56 million in non-recurring expenses between 2017 and 2021.\textsuperscript{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.\textsuperscript{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,


\textsuperscript{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

The HECO Companies have divided their planned infrastructure expenditure in four different categories based on the purpose of the expenditure:

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.

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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.

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**Figure 10. Technical Strategies for Operational Reliability**

<table>
<thead>
<tr>
<th>Issue</th>
<th>Current Methods</th>
<th>Future Methods</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frequency Support</td>
<td>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.</td>
<td>Synchronous condensers and flywheels to provide inertia</td>
</tr>
<tr>
<td></td>
<td>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.</td>
<td>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.</td>
</tr>
<tr>
<td></td>
<td>Spinning reserve is typically provided by synchronous generation that is ready to ramp up or down in response to a frequency deviation.</td>
<td>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.</td>
</tr>
<tr>
<td></td>
<td>Demand response is the reduction of load to balance loss of generation triggered at a predetermined frequency set point and limited by program participants.</td>
<td>Autonomous downward response of inverter based DER resources configured with the advanced inverter frequency-watt function to respond to an over-frequency event.</td>
</tr>
<tr>
<td></td>
<td>Under frequency load shed scheme is the automatic disconnection of blocks of load to re-balance the system during a frequency disturbance.</td>
<td></td>
</tr>
</tbody>
</table>

Voltage Support/Short Circuit Availability

<table>
<thead>
<tr>
<th>Issue</th>
<th>Current Methods</th>
<th>Future Methods</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Reactive power supply and voltage control provided by synchronous generating facilities, excitation systems, and capacitors.</td>
<td>Synchronous condensers to provide reactive power support and short circuit current. Repurposing de-activated generators as condensers.</td>
</tr>
<tr>
<td></td>
<td>Protective relay schemes designed to isolate faults within cycles.</td>
<td>Storage systems such as battery storage, electric vehicles, flywheels, and thermal storage to provide quick and flexible energy sources to stabilize system balancing.</td>
</tr>
<tr>
<td></td>
<td>Fault current supplied by synchronous generators.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Dynamic reactive power capability of synchronous generators and static var compensators.</td>
<td></td>
</tr>
</tbody>
</table>

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).


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.\textsuperscript{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.\textsuperscript{39}

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**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.

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\textsuperscript{38} Electricity Restructuring Act, 2004. S.O. 2004, c. 23 – Bill 100.

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
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.

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

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capabilities for its own operations, especially on the T&D side, in which case these functions would be partially duplicated in the SB.

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:

1. 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.

<table>
<thead>
<tr>
<th>Item</th>
<th>Grid System Operator (“GSO”)</th>
<th>Single Buyer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Work area</td>
<td>Separate from the work areas of other divisions and units within TNB</td>
<td>Separate from the work areas of other divisions and units within TNB</td>
</tr>
<tr>
<td>Sharing of information</td>
<td>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</td>
<td>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</td>
</tr>
<tr>
<td>Accounts</td>
<td>Needs to maintain a separate set of Financial Statutory Accounts, which is audited at least annually and published on the GSO’s website</td>
<td>A separate set of Single Buyer Accounts relating to the performance of its functions as a Single Buyer should be maintained and established</td>
</tr>
<tr>
<td>Access to IT system</td>
<td>1) Only GSO staff can access systems that are only used by the GSO; 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) 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.</td>
<td>Other users of the IT system cannot access confidential information held by the Single Buyer</td>
</tr>
<tr>
<td>Compliance report</td>
<td>Prepare a statement of compliance, and the GSO shall identify a full-time &quot;Compliance Officer&quot; who manages the compliance arrangements</td>
<td>Prepare a statement of compliance, issue guidelines, and provide supporting information to justify compliance</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th></th>
<th>Cost (2005 CAD)</th>
<th>Asset Life (years)</th>
<th>Cost ($000s, 2016 USD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Furniture and equipment</td>
<td>1,174,275</td>
<td>10</td>
<td>1,431</td>
</tr>
<tr>
<td>Leasehold improvements</td>
<td>1,458,998</td>
<td>Length of lease</td>
<td>1,779</td>
</tr>
<tr>
<td>Computer hardware and software</td>
<td>693,839</td>
<td>2.5</td>
<td>846</td>
</tr>
<tr>
<td>Audio visual equipment</td>
<td>135,843</td>
<td>10</td>
<td>166</td>
</tr>
<tr>
<td>Telephone system</td>
<td>49,217</td>
<td>5</td>
<td>60</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>3,512,172</strong></td>
<td></td>
<td><strong>4,281</strong></td>
</tr>
</tbody>
</table>

Note: FX conversion to 2005 USD (1 USD = 1.02 CAD), adjusted for inflation at 2%


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. 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

---

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.

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. 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

---

42 REVConnect website.

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, 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


Figure 16. DSP - Enabling Technologies Proposed by the JU

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 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)

<table>
<thead>
<tr>
<th>Utility</th>
<th>Customers Served</th>
<th>Technology</th>
<th>Five Year Costs ($ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Orange &amp; Rockland Utilities</td>
<td>230,000</td>
<td>ADMS</td>
<td>$13</td>
</tr>
<tr>
<td>Central Hudson Gas &amp; Electric</td>
<td>300,000</td>
<td>DA</td>
<td>$44</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Network upgrades to support DA and ADMS</td>
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<tr>
<td></td>
<td></td>
<td>ADMS</td>
<td>$7</td>
</tr>
<tr>
<td>Niagara Mohawk Power Corporation (National Grid)</td>
<td>1,600,000</td>
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<tr>
<td></td>
<td></td>
<td>ADMS</td>
<td>$14</td>
</tr>
<tr>
<td>AVANGRID (New York State Electric &amp; Gas; Rochester Gas &amp; Electric)</td>
<td>1,250,000</td>
<td>DA</td>
<td>$190</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ADMS</td>
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<tr>
<td></td>
<td></td>
<td>GIS grid model</td>
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</tr>
<tr>
<td></td>
<td></td>
<td>Enterprise analytics platform</td>
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<tr>
<td>Consolidated Edison</td>
<td>3,400,000</td>
<td>DERMS</td>
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<tr>
<td></td>
<td></td>
<td>Green Button Connect</td>
<td>$15</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Overall DSP development costs</td>
<td>$133</td>
</tr>
</tbody>
</table>


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.


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 Hawai’i’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

<table>
<thead>
<tr>
<th>Project Budget Requirement</th>
<th>Phase 1</th>
<th></th>
<th>Phase 2</th>
<th></th>
<th>Phase 3</th>
<th></th>
<th>Total Project</th>
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<td>OPEX</td>
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<td>National Grid</td>
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<td>IT Integration Services</td>
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<td>IT Hardware/Software</td>
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<td>IT Network and communications</td>
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<td></td>
<td></td>
<td>$200,000</td>
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<td>$0</td>
<td>$1,625,000</td>
<td>$355,000</td>
<td>$4,425,000</td>
</tr>
</tbody>
</table>


### 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).

DELIBERABLE 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.
7 Appendix B: Works Cited


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
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’ (“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.

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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.
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**

<table>
<thead>
<tr>
<th>Drivers</th>
<th>Proposed improvements</th>
</tr>
</thead>
<tbody>
<tr>
<td>Meeting the State's clean energy goals</td>
<td>Proposed adding renewables and energy storage; retirement of thermal plants; transmission upgrades and expansion as well as grid modernization to accommodate more renewables</td>
</tr>
<tr>
<td>Aging generation and transmission infrastructure</td>
<td>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</td>
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<tr>
<td>Increasing penetration of distributed energy resources</td>
<td>Utilize advanced grid technologies into the distribution system to provide access to other flexible power resources; deploy autonomous resources</td>
</tr>
<tr>
<td>Moderate load growth</td>
<td>New plant installations</td>
</tr>
<tr>
<td>Continuing the utilities' mandate to provide reliable energy service</td>
<td>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.</td>
</tr>
</tbody>
</table>
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, was 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 listed in Figure 2.

Figure 2. State’s key criteria in evaluating the models

<table>
<thead>
<tr>
<th>Achieve State energy goals</th>
<th>Maximize consumer cost savings</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs</td>
<td>Eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation</td>
</tr>
</tbody>
</table>

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

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3 Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).


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. 

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.

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7 KIUC’s 2017 Annual RPS Status Report had not been released when this memo was finalized. “40%” was retrieved from KIUC’s website (http://website.kiuc.coop/content/about-us, access date: April 3, 2018).

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.” 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%. 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. 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**

<table>
<thead>
<tr>
<th>Island and County</th>
<th>Forecast RPS (%)</th>
<th>Forecasted Renewables (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Molokai Island (Maui County)</td>
<td>142%</td>
<td>8.50</td>
</tr>
<tr>
<td>Hawaii Island (Hawaii County)</td>
<td>80%</td>
<td>235.30</td>
</tr>
<tr>
<td>Maui Island (Maui County)</td>
<td>63%</td>
<td>284.00</td>
</tr>
<tr>
<td>Lanai Island (Maui County)</td>
<td>59%</td>
<td>6.70</td>
</tr>
<tr>
<td>Oahu Island (Honolulu County)</td>
<td>45%</td>
<td>1,299.00</td>
</tr>
</tbody>
</table>


Likewise, KIUC has exceeded the 2016 RPS goal of 30% by having 41.66% of its net electricity sales from renewable energy resources. 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. According to KIUC’s 2016 Annual RPS Status Report, it is on target to exceed the next RPS

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requirement of 70% by 2040. As of 2017, more than 40% of KIUC’s electricity came from renewable energy sources.

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:

- 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.

### 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.

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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16 Ibid.

17 Ibid.

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). 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.

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19 A brief discussion of the average age of retired oil-fired plants is discussed in Task 1.1.3.
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. 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. 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

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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$)


Figure 10. MECO in-service T&D infrastructure assets (2016$)


²² Ibid.
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.

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

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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**

![PV Generation Growth Chart]


**Figure 13. Installed Residential and Commercial PV**

<table>
<thead>
<tr>
<th>Utility</th>
<th>Number of PV Systems</th>
<th>PV Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Residential</td>
<td>Commercial</td>
</tr>
<tr>
<td>Hawaiian Electric</td>
<td>44,267</td>
<td>1522</td>
</tr>
<tr>
<td>Maui Electric</td>
<td>10,148</td>
<td>782</td>
</tr>
<tr>
<td>Hawaiian Electric Light</td>
<td>10,263</td>
<td>647</td>
</tr>
<tr>
<td>Totals</td>
<td>64,678</td>
<td>2,951</td>
</tr>
</tbody>
</table>


**Figure 14. DG-PV Forecast**

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\(^{25}\) Ibid.
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

<table>
<thead>
<tr>
<th>Island</th>
<th>2016</th>
<th>2017</th>
<th>2020</th>
<th>2025</th>
<th>2030</th>
<th>2035</th>
<th>2040</th>
<th>2045</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oahu</td>
<td>407</td>
<td>479</td>
<td>606</td>
<td>867</td>
<td>1,175</td>
<td>1,484</td>
<td>1,793</td>
<td>2,101</td>
</tr>
<tr>
<td>Maui</td>
<td>98</td>
<td>115</td>
<td>132</td>
<td>178</td>
<td>243</td>
<td>307</td>
<td>371</td>
<td>435</td>
</tr>
<tr>
<td>Lanai</td>
<td>0.8</td>
<td>1.3</td>
<td>1.5</td>
<td>2.5</td>
<td>3.8</td>
<td>5.2</td>
<td>6.5</td>
<td>7.8</td>
</tr>
<tr>
<td>Molokai</td>
<td>2.1</td>
<td>2.5</td>
<td>3.4</td>
<td>4.0</td>
<td>4.7</td>
<td>5.5</td>
<td>6.3</td>
<td>7.1</td>
</tr>
<tr>
<td>Hawaii</td>
<td>88</td>
<td>103</td>
<td>115</td>
<td>174</td>
<td>244</td>
<td>315</td>
<td>386</td>
<td>456</td>
</tr>
<tr>
<td>Total</td>
<td>596</td>
<td>701</td>
<td>858</td>
<td>1,226</td>
<td>1,671</td>
<td>2,117</td>
<td>2,563</td>
<td>3,007</td>
</tr>
</tbody>
</table>


27 Ibid.

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.\textsuperscript{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.\textsuperscript{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**

\begin{itemize}
\item Net Peak Forecast
\item Oahu
\item Net Peak Forecast
\item Maui
\item Net Peak Forecast
\item Lanai
\item Net Peak Forecast
\item Molokai
\item Net Peak Forecast
\item Hawaii
\end{itemize}


### 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, \textsuperscript{29}HECO Companies. *PSIP Update Report*. December 23, 2016. Book 3. Page J-50 – J-55.

\textsuperscript{30}Ibid.
from 2017 to 2021) of -0.02% and 2.33% in the different islands\textsuperscript{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

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,\textsuperscript{32} about 326 MW of distributed solar generation,\textsuperscript{33} and about 110 MW of demand response program resources.\textsuperscript{34} Figure 17 shows the renewable generation

\textsuperscript{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%.


\textsuperscript{33} Ibid.

\textsuperscript{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. 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.

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. In total, an additional 695.1 MW of renewable energy is anticipated to be

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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)](image)

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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. 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."

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

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MW of Westside Pumped Hydro Storage and 12 MW of solar plus storage. This will increase the total renewable energy in Kauai to 138.9 MW by 2025.

Figure 20. PSIP near-term resource plan summary for Hawaii County


41 Ibid.
4.1.2 Retirements

As mentioned in the PSIP, according to E3 Plans\textsuperscript{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.\textsuperscript{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\textsuperscript{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.”\textsuperscript{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.”\textsuperscript{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.\textsuperscript{47} The HECO Companies stated in the PSIP that

\textsuperscript{42} Includes “E3 Plan,” “E3 Plan with LNG,” “E3 Plan with LNG; Keahole & HEP LNG Conversion.”


\textsuperscript{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.


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.”

Below are the identified transmission projects in Hawaii County. 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 Reconstructor, 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:

- **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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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.” 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.”

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). The goal in the near term is to integrate “advanced

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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."  

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. 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."

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.

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. 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." 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.

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.

56 Ibid. Page 106.
57 Ibid. Page 107.
58 Ibid.
59 Ibid. Page 106.
60 Ibid. Page 107.
Furthermore, the HECO Companies will deploy autonomous resources like the IEEE 1547-compliant advanced inverters\(^1\) 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.”\(^2\) 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.

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\(^1\) Ibid.

\(^2\) Ibid. Page 82.
### Figure 22. The HECO Companies’ strategies for maintaining operating reliability

<table>
<thead>
<tr>
<th>Issue</th>
<th>Current Methods</th>
<th>Future Methods</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frequency Support</td>
<td><strong>Inertia</strong> 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.</td>
<td>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.</td>
</tr>
<tr>
<td>Voltage Support/Short-Circuit Availability</td>
<td>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.</td>
<td>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.</td>
</tr>
</tbody>
</table>


### 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

<table>
<thead>
<tr>
<th></th>
<th>O'ahu</th>
<th>Maui</th>
<th>Lanai</th>
<th>Molokai</th>
<th>Hawaii</th>
</tr>
</thead>
<tbody>
<tr>
<td>Contingency FFR1</td>
<td>2019</td>
<td>2019</td>
<td>2019</td>
<td>2019</td>
<td>2020</td>
</tr>
<tr>
<td>1-hour regulation BESS</td>
<td>2020</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Synchronous condensers</td>
<td>2021</td>
<td>2020</td>
<td>2019</td>
<td>2019</td>
<td>2020</td>
</tr>
<tr>
<td>Load-shifting energy storage</td>
<td>2020</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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.

<table>
<thead>
<tr>
<th>Post-April PSIP Plan</th>
<th>E3 Plan</th>
<th>E3 Plan with LNG</th>
<th>E3 Plan with Generation Modernization</th>
<th>E3 Plan with LNG and Generation Modernization</th>
<th>100% renewable by 2020</th>
<th>100% renewable by 2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO MECO - Maui MECO-Lanai MECO-Molokai HELCO</td>
<td>x</td>
<td>x</td>
<td></td>
<td></td>
<td>x</td>
<td>x</td>
</tr>
</tbody>
</table>


The PSIP document explained the plans63 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;

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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.

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\(^{65}\) 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.
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. 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.”

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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.\(^6\) 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.”

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

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**

![Graph showing new installation in Hawaii county under different plans](image)

**Figure 30. New installation in Hawaii County by fuel type**

![Graph showing new installation in Hawaii County by fuel type](image)

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

![Graph showing potential retirements in Honolulu County under different plans]

Figure 32. List of potential retirements in Honolulu county

<table>
<thead>
<tr>
<th>Unit</th>
<th>Fuel</th>
<th>Net capacity (MW)</th>
<th>Age as of 2016</th>
<th>Delivery type</th>
<th>Post April PSIP Plan</th>
<th>E3 Plan with Generation Modernization</th>
<th>E3 Plan with LNG and Generation Modernization</th>
</tr>
</thead>
<tbody>
<tr>
<td>AES</td>
<td>Coal</td>
<td>180.00</td>
<td>25</td>
<td>Baseload</td>
<td>2022</td>
<td>2022</td>
<td>2022</td>
</tr>
<tr>
<td>Waiau 3</td>
<td>LSFO</td>
<td>47.00</td>
<td>70</td>
<td>Cycling</td>
<td>2023</td>
<td>2023</td>
<td>2023</td>
</tr>
<tr>
<td>Waiau 4</td>
<td>LSFO</td>
<td>46.50</td>
<td>67</td>
<td>Cycling</td>
<td>2023</td>
<td>2023</td>
<td>2023</td>
</tr>
<tr>
<td>Waiau 5</td>
<td>LSFO</td>
<td>54.50</td>
<td>58</td>
<td>Cycling</td>
<td>2030</td>
<td>2026</td>
<td>2026</td>
</tr>
<tr>
<td>Waiau 6</td>
<td>LSFO</td>
<td>53.70</td>
<td>56</td>
<td>Cycling</td>
<td>2030</td>
<td>2026</td>
<td>2026</td>
</tr>
<tr>
<td>Waiau 7</td>
<td>LSFO</td>
<td>83.30</td>
<td>51</td>
<td>Baseload</td>
<td>2032</td>
<td>2031</td>
<td>2031</td>
</tr>
<tr>
<td>Waiau 8</td>
<td>LSFO</td>
<td>86.20</td>
<td>49</td>
<td>Baseload</td>
<td>2032</td>
<td>2031</td>
<td>2031</td>
</tr>
<tr>
<td>Kahe 1</td>
<td>LSFO</td>
<td>82.20</td>
<td>54</td>
<td>Baseload</td>
<td>2027</td>
<td>2035</td>
<td>2035</td>
</tr>
<tr>
<td>Kahe 2</td>
<td>LSFO</td>
<td>82.20</td>
<td>53</td>
<td>Baseload</td>
<td>2027</td>
<td>2035</td>
<td>2035</td>
</tr>
<tr>
<td>Kahe 3</td>
<td>LSFO</td>
<td>86.20</td>
<td>47</td>
<td>Baseload</td>
<td>2034</td>
<td>2039</td>
<td>2039</td>
</tr>
<tr>
<td>Kahe 4</td>
<td>LSFO</td>
<td>85.30</td>
<td>45</td>
<td>Baseload</td>
<td>2034</td>
<td>2039</td>
<td>2039</td>
</tr>
<tr>
<td>Kahe 5</td>
<td>LSFO</td>
<td>134.60</td>
<td>43</td>
<td>Baseload</td>
<td>2030</td>
<td>2028</td>
<td>2028</td>
</tr>
<tr>
<td>Kahe 6</td>
<td>LSFO</td>
<td>133.80</td>
<td>36</td>
<td>Baseload</td>
<td>2025</td>
<td>2028</td>
<td>2028</td>
</tr>
</tbody>
</table>

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.

<table>
<thead>
<tr>
<th>Unit</th>
<th>Fuel</th>
<th>Net capacity (MW)</th>
<th>Age as of 2016</th>
<th>Delivery type</th>
<th>Retirement year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kahului 1</td>
<td>IFO</td>
<td>5.00</td>
<td>68</td>
<td>Peaking</td>
<td>2022</td>
</tr>
<tr>
<td>Kahului 2</td>
<td>IFO</td>
<td>5.00</td>
<td>67</td>
<td>Peaking</td>
<td>2022</td>
</tr>
<tr>
<td>Kahului 3</td>
<td>IFO</td>
<td>11.50</td>
<td>62</td>
<td>Baseload</td>
<td>2022</td>
</tr>
<tr>
<td>Kahului 4</td>
<td>IFO</td>
<td>12.50</td>
<td>50</td>
<td>Baseload</td>
<td>2022</td>
</tr>
<tr>
<td>Ma'alaea 4</td>
<td>LSD</td>
<td>5.60</td>
<td>43</td>
<td>Peaking</td>
<td>N/A</td>
</tr>
<tr>
<td>Ma'alaea 5</td>
<td>LSD</td>
<td>5.60</td>
<td>43</td>
<td>Peaking</td>
<td>N/A</td>
</tr>
<tr>
<td>Ma'alaea 6</td>
<td>LSD</td>
<td>5.60</td>
<td>43</td>
<td>Peaking</td>
<td>N/A</td>
</tr>
<tr>
<td>Ma'alaea 7</td>
<td>LSD</td>
<td>5.60</td>
<td>38</td>
<td>Peaking</td>
<td>N/A</td>
</tr>
<tr>
<td>Ma'alaea 8</td>
<td>LSD</td>
<td>5.60</td>
<td>38</td>
<td>Peaking</td>
<td>N/A</td>
</tr>
<tr>
<td>Ma'alaea 9</td>
<td>LSD</td>
<td>5.60</td>
<td>38</td>
<td>Peaking</td>
<td>N/A</td>
</tr>
<tr>
<td>Ma'alaea 10</td>
<td>LSD</td>
<td>12.50</td>
<td>36</td>
<td>Cycling</td>
<td>2045</td>
</tr>
<tr>
<td>Ma'alaea 11</td>
<td>LSD</td>
<td>12.50</td>
<td>36</td>
<td>Cycling</td>
<td>2045</td>
</tr>
<tr>
<td>Ma'alaea 12</td>
<td>LSD</td>
<td>12.50</td>
<td>28</td>
<td>Cycling</td>
<td>2045</td>
</tr>
<tr>
<td>Ma'alaea 13</td>
<td>LSD</td>
<td>12.50</td>
<td>28</td>
<td>Cycling</td>
<td>2045</td>
</tr>
</tbody>
</table>


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

<table>
<thead>
<tr>
<th>Unit</th>
<th>Fuel</th>
<th>Net capacity (MW)</th>
<th>Age as of 2016</th>
<th>Delivery type</th>
<th>Post April PSIP Plan</th>
<th>E3 Plan</th>
<th>E3 Plan with LNG</th>
<th>E3 Plan with LNG &amp; Keahole &amp; HEP LNG Conversion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Puna Steam</td>
<td>IFO</td>
<td>15.70</td>
<td>46</td>
<td>Frequency Regulation, Load Following, Cycling</td>
<td>2025</td>
<td>2020</td>
<td>2020</td>
<td>2020</td>
</tr>
<tr>
<td>Hill 5</td>
<td>IFO</td>
<td>13.50</td>
<td>51</td>
<td>Frequency Regulation, Load Following, Cycling</td>
<td>2027</td>
<td>2020</td>
<td>2020</td>
<td>2020</td>
</tr>
<tr>
<td>Hill 6</td>
<td>IFO</td>
<td>20.20</td>
<td>42</td>
<td>Frequency Regulation, Load Following, Cycling</td>
<td>2030</td>
<td>2020</td>
<td>2020</td>
<td>2020</td>
</tr>
<tr>
<td>Keahole CT2</td>
<td>LSD</td>
<td>13.80</td>
<td>27</td>
<td>Peaking, Emergency, Black start</td>
<td>N/A</td>
<td>2040</td>
<td>2040</td>
<td>2040</td>
</tr>
</tbody>
</table>


5.3 System improvements planned: grid

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.

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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. 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. 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.”

This transmission project will consist of three parts:

- Maalaea–Puunene Substation reconductoring;
- Maalaea to Waihu Substation 69 kV reconductoring; and
- Waihu 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.

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. 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.”

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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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.”

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.” 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.”

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.”

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.

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81 Ibid.

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.

DELCIVERABLE 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


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

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>ACC</td>
<td>Arizona Corporation Commission</td>
</tr>
<tr>
<td>APS</td>
<td>Arizona Public Service Company</td>
</tr>
<tr>
<td>B Corp</td>
<td>Benefit corporations</td>
</tr>
<tr>
<td>CMVE</td>
<td>Competitive Market Value Estimate</td>
</tr>
<tr>
<td>Co-op</td>
<td>Cooperative utility</td>
</tr>
<tr>
<td>CTC</td>
<td>Competitive Transaction Charge</td>
</tr>
<tr>
<td>DBEDT</td>
<td>Hawaii Department of Business, Economic Development, and Tourism</td>
</tr>
<tr>
<td>DER</td>
<td>Distributed Energy Resource</td>
</tr>
<tr>
<td>DRC</td>
<td>Debt Retirement Charge</td>
</tr>
<tr>
<td>EIA</td>
<td>US Energy Information Administration</td>
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<td>FERC</td>
<td>Federal Energy Regulatory Commission</td>
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<td>HECO</td>
<td>Hawaiian Electric Company, Inc.</td>
</tr>
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<td>Hawaiian Electric Industries, Inc.</td>
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<tr>
<td>HELCO</td>
<td>Hawaii Electric Light Company, Inc.</td>
</tr>
<tr>
<td>HERA</td>
<td>Hawaii Electricity Reliability Administrator</td>
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<tr>
<td>HSEO</td>
<td>Hawaii State Energy Office</td>
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<tr>
<td>IDER</td>
<td>Integrated DER</td>
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<tr>
<td>IESO</td>
<td>Independent Electricity System Operator</td>
</tr>
<tr>
<td>IOU</td>
<td>Investor-Owned Utility</td>
</tr>
<tr>
<td>IPP</td>
<td>Independent Power Producer</td>
</tr>
<tr>
<td>IRP</td>
<td>Integrated Resource Plan</td>
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<tr>
<td>KIUC</td>
<td>Kauai Island Utility Cooperative</td>
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<tr>
<td>LEI</td>
<td>London Economics International LLC</td>
</tr>
<tr>
<td>MECO</td>
<td>Maui Electric Company, Ltd.</td>
</tr>
<tr>
<td>Munis</td>
<td>Municipal utilities</td>
</tr>
<tr>
<td>NMP</td>
<td>Nine Mile Point</td>
</tr>
<tr>
<td>NYSE</td>
<td>New York Stock Exchange</td>
</tr>
<tr>
<td>OEFC</td>
<td>Ontario Electric Financial Corporation</td>
</tr>
<tr>
<td>OPG</td>
<td>Ontario Power generation</td>
</tr>
<tr>
<td>PILOT</td>
<td>Payment in Lieu of Taxes</td>
</tr>
<tr>
<td>PPA</td>
<td>Power Purchase Agreement</td>
</tr>
<tr>
<td>PSIP</td>
<td>Power Supply Improvement Plans</td>
</tr>
<tr>
<td>PUC</td>
<td>Public Utilities Commission</td>
</tr>
<tr>
<td>RSE</td>
<td>Revenue Stream Estimate</td>
</tr>
<tr>
<td>SB</td>
<td>Single Buyer</td>
</tr>
<tr>
<td>SCO</td>
<td>Stranded Cost Obligation</td>
</tr>
<tr>
<td>TEP</td>
<td>Tucson Electric Power</td>
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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 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.

<table>
<thead>
<tr>
<th>Ownership</th>
<th>Generation assets</th>
<th>Transmission/distribution (“T&amp;D”) assets</th>
</tr>
</thead>
<tbody>
<tr>
<td>Traditional utility models:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- investor-owned utility (“IOU”) (status quo or new owner),</td>
<td>No stranded costs</td>
<td>T&amp;D assets remain under regulated regime, hence no stranded costs are expected</td>
</tr>
<tr>
<td>- municipal utility (“muni”),</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- cooperative (co-op), and</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- hybrid - majority government owned (“hybrid”)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Integrated Distributed Energy Resources System Operator (“IDER’)</td>
<td>Potential for stranded costs if generation assets have lower value under a new regulatory model than under current regulated regime</td>
<td>T&amp;D assets remain under regulated regime, hence no stranded costs are expected</td>
</tr>
<tr>
<td>Single Buyer</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Grid defection</td>
<td>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>
<td></td>
</tr>
</tbody>
</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\textsuperscript{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.\textsuperscript{3}

In a follow-up work paper discussing potential changes in regulatory models,\textsuperscript{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.

\textsuperscript{2} Based on LEI’s analysis of regulatory filings by the HECO Companies and KIUC.

\textsuperscript{3} The annual straight-line remaining-life depreciation rates vary by generation asset accounts, but average approximately 2%.

\textsuperscript{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, was 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 listed in Figure 2.

---

**Figure 2. State’s key criteria for evaluating the models**

- **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: Scope of Services under Contract No. 65595*

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5 Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).


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.  

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.

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.

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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,

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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. 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”):

\[
SCO = (RSE \text{ minus CMVE}) \times L
\]

where:

- **RSE** is the Revenues 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

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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.

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**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*

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### 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

<table>
<thead>
<tr>
<th>Approach to recover stranded costs</th>
<th>Exit fee</th>
<th>Rate freeze/cap</th>
<th>Securitization/rate reduction</th>
</tr>
</thead>
<tbody>
<tr>
<td>Charged to those who purchase power from other generator and not the incumbent.</td>
<td>Access fee</td>
<td>Charged higher prices to regulated components to compensate for stranded costs</td>
<td>Lower rate to customers with securitization of certain transition costs. Upfront payment to utility for some stranded costs.</td>
</tr>
</tbody>
</table>

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.


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), 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.

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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 assets13 (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.

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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.

**2016 average electricity rates for residential customers**

<table>
<thead>
<tr>
<th>Island</th>
<th>Average cents/kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oahu</td>
<td>25</td>
</tr>
<tr>
<td>Maui</td>
<td>30</td>
</tr>
<tr>
<td>Kauai</td>
<td>35</td>
</tr>
<tr>
<td>Hawaii</td>
<td>40</td>
</tr>
<tr>
<td>Molokai</td>
<td>45</td>
</tr>
<tr>
<td>Lanai</td>
<td>50</td>
</tr>
</tbody>
</table>

*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\textsuperscript{14} for Hawaii’s four utilities, which include the net value of production, transmission, distribution, and other\textsuperscript{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,\textsuperscript{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\textsuperscript{17} assumed a net cost of plant in service of $657 million where generation assets comprised approximately 26\% of the value. MECO\textsuperscript{18} and KIUC\textsuperscript{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.

\textsuperscript{14} As of the target date of the source data, which ranges from 2015 to 2017 as noted in the notes of Figure 4.

\textsuperscript{15} Includes vehicles, land, and general assets.

\textsuperscript{16} HAWAII PUC Docket 2016-0328. “Application for Approval of General Rate Case and Revised Rate Schedules and Rules.” Filed on September 16, 2016.

\textsuperscript{17} HAWAII PUC Docket 2015-0170. “Application for Approval of General Rate Case and Revised Rate Schedules and Rules.” Filed on June 17, 2015.

\textsuperscript{18} HAWAII PUC Docket 2014-0318. “Application for Approval of General Rate Case.” Filed on December 30, 2014.

\textsuperscript{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](image)

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

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\[^{21}\] 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, 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, 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 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.


24 Task 1.1.2. Hawaii Maps for Service Areas of Each County.

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, and 88 MW (combined cycle combustion turbine and diesel internal combustion engines) is between 20 and 30 years old. 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, 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.

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, 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

26 These include the following plants: Maalaea 17 (21 MW diesel), Maalaea 18 (16 MW diesel), and Maalaea 19 (21 MW diesel).
27 Ibid.
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,\textsuperscript{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.

\textbf{Figure 7. HELCO thermal generation fleet age}

\begin{center}
\includegraphics[width=0.5\textwidth]{helco_thermal_generation_fleet_age.png}
\end{center}

\textit{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.\textsuperscript{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.

\textsuperscript{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.”

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.
Appendix B: List of works consulted


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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<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>DBEDT</td>
<td>Hawaii Department of Business, Economic Development and Tourism</td>
</tr>
<tr>
<td>EIA</td>
<td>Energy Information Administration</td>
</tr>
<tr>
<td>ERCOT</td>
<td>Electric Reliability Council of Texas</td>
</tr>
<tr>
<td>FERC</td>
<td>Federal Energy Regulatory Commission</td>
</tr>
<tr>
<td>HECO</td>
<td>Hawaiian Electric Company</td>
</tr>
<tr>
<td>HEI</td>
<td>Hawaiian Electric Industries</td>
</tr>
<tr>
<td>IOU</td>
<td>Investor Owned Utility</td>
</tr>
<tr>
<td>KIUC</td>
<td>Kauai Island Utility Cooperative</td>
</tr>
<tr>
<td>LEI</td>
<td>London Economics International</td>
</tr>
<tr>
<td>M&amp;A</td>
<td>Mergers and Acquisitions</td>
</tr>
<tr>
<td>MCG</td>
<td>Meister Consultants Group</td>
</tr>
<tr>
<td>PSC</td>
<td>Public Services Commission</td>
</tr>
<tr>
<td>PUC</td>
<td>Public Utility Commission</td>
</tr>
<tr>
<td>PUD</td>
<td>Public Utility District</td>
</tr>
<tr>
<td>REV</td>
<td>Reforming the Energy Vision</td>
</tr>
<tr>
<td>SWEPCO</td>
<td>Southwestern Electric Power Company</td>
</tr>
<tr>
<td>VEMC</td>
<td>Valley Electric Member Cooperative</td>
</tr>
<tr>
<td>WMECO</td>
<td>Western Massachusetts Electric Company</td>
</tr>
</tbody>
</table>
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, 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 criteria3 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).


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

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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 utility7 (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

<table>
<thead>
<tr>
<th>Ownership Model Change</th>
<th>Count</th>
</tr>
</thead>
<tbody>
<tr>
<td>IOU-Only Activity</td>
<td>22</td>
</tr>
<tr>
<td>IOU transitioning to Cooperative Utility</td>
<td>3</td>
</tr>
<tr>
<td>IOU transitioning to Municipal Utility</td>
<td>2</td>
</tr>
<tr>
<td>Cooperative Utility transitioning to IOU</td>
<td>2</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>29</strong></td>
</tr>
</tbody>
</table>

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.
<table>
<thead>
<tr>
<th>Ownership Change Type</th>
<th>State</th>
<th>Year</th>
<th>Acquired Utility</th>
<th>Acquiring Entity</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>IOU to Cooperative HI</td>
<td>2002</td>
<td>Kauai Electric</td>
<td>Kauai Island Utility Cooperative (KIUC)</td>
<td>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.</td>
<td></td>
</tr>
<tr>
<td>IOU to Cooperative MT</td>
<td>1998</td>
<td>PacifiCorp (MT service area)</td>
<td>Flathead Electric Cooperative</td>
<td>An existing cooperative utility purchased the Montana service territory of PacifiCorp (dba Pacific Power).</td>
<td></td>
</tr>
<tr>
<td>IOU to Municipality TX</td>
<td>2010</td>
<td>Xcel (Lubbock service area)</td>
<td>Lubbock Power &amp; Light</td>
<td>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.</td>
<td></td>
</tr>
<tr>
<td>Cooperative to IOU LA</td>
<td>2010</td>
<td>Valley Electric Member Cooperative</td>
<td>Southwestern Electric Power Company (SWEPCO)</td>
<td>An existing IOU, SWEPCO acquired the assets of Valley Electric, with cooperative members voting to support the acquisition.</td>
<td></td>
</tr>
<tr>
<td>Cooperative to IOU TX</td>
<td>2002</td>
<td>Cap Rock Electric Cooperative</td>
<td>Cap Rock Energy</td>
<td>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</td>
<td></td>
</tr>
</tbody>
</table>
## Figure 4. Total Sample of Utility Transactions and Changes in Ownership Model

<table>
<thead>
<tr>
<th>Acquired/Merged Utility</th>
<th>State</th>
<th>Year</th>
<th>Outgoing</th>
<th>Incoming</th>
<th>Change in Ownership Model</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cleco Power</td>
<td>LA</td>
<td>2016</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>United Illuminating Company</td>
<td>CT</td>
<td>2015</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>Rochester Gas &amp; Electric Corp</td>
<td>NY</td>
<td>2015</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>Interstate Power &amp; Light (Minnesota service territory)</td>
<td>MN</td>
<td>2015</td>
<td>Investor Owned</td>
<td>Cooperative</td>
<td>Yes</td>
</tr>
<tr>
<td>Upper Peninsula Power Co</td>
<td>MI</td>
<td>2014</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>UNS Electric</td>
<td>AZ</td>
<td>2014</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>Maine Public Service Company</td>
<td>ME</td>
<td>2014</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>Sierra Pacific Power</td>
<td>NV</td>
<td>2013</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>Central Hudson Gas &amp; Electric</td>
<td>NY</td>
<td>2013</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>Puget Sound Energy (Jefferson County service territory)</td>
<td>WA</td>
<td>2013</td>
<td>Investor Owned</td>
<td>Municipal</td>
<td>Yes</td>
</tr>
<tr>
<td>Green Mountain Power</td>
<td>VT</td>
<td>2012</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>Granite State</td>
<td>NH</td>
<td>2012</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>Western Massachusetts Electric Co (WMECO)</td>
<td>MA</td>
<td>2012</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>Sierra Pacific Power (California service territory)</td>
<td>CA</td>
<td>2011</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>Southwest Public Service Co (Lubbock service territory)</td>
<td>TX</td>
<td>2010</td>
<td>Investor Owned</td>
<td>Municipal</td>
<td>Yes</td>
</tr>
<tr>
<td>Valley Electric Member Corp</td>
<td>LA</td>
<td>2010</td>
<td>Cooperative</td>
<td>Investor Owned</td>
<td>Yes</td>
</tr>
<tr>
<td>Acquila, Inc</td>
<td>CO</td>
<td>2008</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>Texas - New Mexico Power</td>
<td>NM</td>
<td>2007</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>Union Light, Heat &amp; Power Co</td>
<td>KY</td>
<td>2006</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>Cheyenne Light Fuel &amp; Power Co</td>
<td>WY</td>
<td>2005</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>Central Illinois Light Co</td>
<td>IL</td>
<td>2003</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>Cap Rock Energy Cooperative</td>
<td>TX</td>
<td>2002</td>
<td>Cooperative</td>
<td>Investor Owned</td>
<td>Yes</td>
</tr>
<tr>
<td>Company Name</td>
<td>State</td>
<td>Year</td>
<td>Ownership Type</td>
<td>Status</td>
<td></td>
</tr>
<tr>
<td>--------------------------------------------------</td>
<td>-------</td>
<td>------</td>
<td>----------------</td>
<td>----------</td>
<td></td>
</tr>
<tr>
<td>Kauai Electric</td>
<td>HI</td>
<td>2002</td>
<td>Investor Owned</td>
<td>Cooperative</td>
<td>Yes</td>
</tr>
<tr>
<td>Bangor Hydro-Electric Co</td>
<td>ME</td>
<td>2001</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>Louisville Gas &amp; Electric Co</td>
<td>KY</td>
<td>2000</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>St Joseph Light &amp; Power Co</td>
<td>MO</td>
<td>2000</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>Commonwealth Electric Co</td>
<td>MA</td>
<td>1999</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>Central Illinois Light Co</td>
<td>IL</td>
<td>1999</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>Pacific Power (Montana service territory)</td>
<td>MT</td>
<td>1998</td>
<td>Investor Owned</td>
<td>Cooperative</td>
<td>Yes</td>
</tr>
<tr>
<td>Interstate Power Co</td>
<td>IA</td>
<td>1998</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>IES Utilities Inc</td>
<td>IA</td>
<td>1998</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
<tr>
<td>Wisconsin Power &amp; Light Co</td>
<td>WI</td>
<td>1998</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>No</td>
</tr>
</tbody>
</table>
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

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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.

PacifiCorp’s rates in the acquired territory, though the cooperative would later be permitted to align its rates.\footnote{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} 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.\footnote{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}

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.\footnote{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.}

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.\footnote{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} 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,\footnote{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} 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.\footnote{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.  

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.

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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), 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), 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

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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, 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. 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. 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

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](image)

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

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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.\textsuperscript{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).\textsuperscript{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

\textsuperscript{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.

\textsuperscript{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.

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.

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**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**

<table>
<thead>
<tr>
<th>Utility</th>
<th>State</th>
<th>Change in Delivery Charges</th>
<th>Change in Supply Charges</th>
<th>Total Change in Rates</th>
</tr>
</thead>
<tbody>
<tr>
<td>Central Hudson Gas &amp; Electric</td>
<td>NY</td>
<td>$0.011</td>
<td>-$0.001</td>
<td>$0.010</td>
</tr>
<tr>
<td>Granite State</td>
<td>NH</td>
<td>$0.015</td>
<td>-$0.012</td>
<td>$0.003</td>
</tr>
<tr>
<td>Rochester Gas &amp; Electric Corp</td>
<td>NY</td>
<td>$0.009</td>
<td>$0.001</td>
<td>$0.011</td>
</tr>
<tr>
<td>Sierra Pacific Power</td>
<td>NV</td>
<td>$0.004</td>
<td>-$0.014</td>
<td>-$0.010</td>
</tr>
<tr>
<td>United Illuminating Company</td>
<td>CT</td>
<td>-$0.014</td>
<td>$0.014</td>
<td>$0.000</td>
</tr>
<tr>
<td>WMECO</td>
<td>MA</td>
<td>-$0.015</td>
<td>$0.022</td>
<td>$0.007</td>
</tr>
<tr>
<td><strong>Average</strong></td>
<td></td>
<td><strong>$0.002</strong></td>
<td><strong>$0.002</strong></td>
<td><strong>$0.003</strong></td>
</tr>
</tbody>
</table>

Source: Energy Information Administration, Form 861, 1990-Current. n=6 utilities; only utilities with both bundled and delivery rates included.
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.


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, 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, 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

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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.


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

<table>
<thead>
<tr>
<th>Acquired/Merged Utility</th>
<th>Year</th>
<th>New Parent Company</th>
<th>Outgoing</th>
<th>Incoming</th>
<th>1 Year Prior to Transaction</th>
<th>3 Years Post Transaction</th>
</tr>
</thead>
<tbody>
<tr>
<td>UNS Electric</td>
<td>2014</td>
<td>Fortis Inc</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>Baa2</td>
<td>A3</td>
</tr>
<tr>
<td>Sierra Pacific Power</td>
<td>2013</td>
<td>MidAmerican Energy Holdings Co</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>Baa3</td>
<td>Baa1</td>
</tr>
<tr>
<td>Central Hudson Gas &amp; Electric</td>
<td>2013</td>
<td>Cascade Acquisition Sub Inc (Fortis)</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>A3</td>
<td>A2</td>
</tr>
<tr>
<td>Western Massachusetts Electric Co (WMECO)</td>
<td>2012</td>
<td>Northeast Utilities</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>Baa2</td>
<td>A3</td>
</tr>
<tr>
<td>Southwest Public Service Co (Lubbock service territory)</td>
<td>2010</td>
<td>Lubbock Power &amp; Light</td>
<td>Investor Owned</td>
<td>Municipal</td>
<td>A1</td>
<td></td>
</tr>
<tr>
<td>Acquila, Inc</td>
<td>2008</td>
<td>Black Hills Power Inc</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>Baa2</td>
<td>Baa2</td>
</tr>
<tr>
<td>Texas - New Mexico Power</td>
<td>2007</td>
<td>PNM Resources</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>Baa3</td>
<td>Baa3</td>
</tr>
<tr>
<td>Union Light, Heat &amp; Power Co</td>
<td>2006</td>
<td>Duke Energy</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>Baa1</td>
<td>Baa1</td>
</tr>
<tr>
<td>Central Illinois Light Co</td>
<td>2003</td>
<td>Ameren Corp</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>A3 *-</td>
<td>Baa2 *-</td>
</tr>
<tr>
<td>Louisville Gas &amp; Electric Co</td>
<td>2000</td>
<td>PowerGen PLC</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>Aa3</td>
<td>A2</td>
</tr>
<tr>
<td>Commonwealth Electric Co</td>
<td>1999</td>
<td>NSTAR</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>A2</td>
<td></td>
</tr>
<tr>
<td>Central Illinois Light Co</td>
<td>1999</td>
<td>AES Corporation</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>Aa3 *-</td>
<td>A3 *-</td>
</tr>
<tr>
<td>Interstate Power Co</td>
<td>1998</td>
<td>Alliant</td>
<td>Investor Owned</td>
<td>Investor Owned</td>
<td>A2</td>
<td></td>
</tr>
<tr>
<td>Wisconsin Power &amp; Light Co</td>
<td>1998</td>
<td></td>
<td></td>
<td></td>
<td>Aa3</td>
<td>Aa3</td>
</tr>
</tbody>
</table>

*Source: Moody’s. Data not available for all utilities.*
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

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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.

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.


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 impact 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.

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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,\textsuperscript{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.

\textsuperscript{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. 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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<th>Full Form</th>
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<tr>
<td>BTM</td>
<td>Behind-the-meter</td>
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<tr>
<td>CEO</td>
<td>Chief Executive Officer</td>
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<td>DBEDT</td>
<td>Hawaii Department of Business, Economic Development, and Tourism</td>
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<tr>
<td>DER</td>
<td>Distributed energy resource</td>
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<td>DSP</td>
<td>Distribution system platform</td>
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<tr>
<td>EAF</td>
<td>Equivalent availability factor</td>
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<td>EFORD</td>
<td>Equivalent forced outage rate-demand</td>
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<tr>
<td>EFOF</td>
<td>Equivalent forced outage factor</td>
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<td>Federal Energy Regulatory Commission</td>
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<td>HAR</td>
<td>Hawaii Administrative Rules</td>
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<td>HEI</td>
<td>Hawaiian Electric Industries</td>
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<td>HELCO</td>
<td>Hawaii Electric Light Company</td>
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<td>HERA</td>
<td>Hawaii Electricity Reliability Administrator</td>
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<td>ICT</td>
<td>Information and communication technologies</td>
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<td>IDER</td>
<td>Integrated distributed energy resource</td>
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<td>IOU</td>
<td>Investment owned utility</td>
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<td>IPP</td>
<td>Independent Power Producers</td>
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<td>Kauai Island Utility Cooperative</td>
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<td>London Economics International, LLC</td>
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<td>Long Island Power Authority</td>
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<td>MCG</td>
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<td>MECO</td>
<td>Maui Electric Company</td>
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<tr>
<td>Acronym</td>
<td>Description</td>
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<tr>
<td>NRECA</td>
<td>National Rural Electrical Cooperative Association</td>
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<td>PPA</td>
<td>Power purchase agreement</td>
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<td>PSC</td>
<td>Public Service Commission</td>
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<td>Public Service Enterprise Group</td>
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<td>PUC</td>
<td>Public Utilities Commission of the State of Hawaii</td>
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<td>Public Utility Regulatory Policies Act</td>
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<td>National Rural Utilities Service</td>
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<td>SAIDI</td>
<td>System average interruption duration index</td>
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<td>System average interruption frequency index</td>
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<td>Single Buyer</td>
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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**

![Figure 1. State’s key criteria](source: Scope of Services under Contract No. 65595)

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\(^2\) 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.
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

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\(^5\) 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.” 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 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. 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.”

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 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).*

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. 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.
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.
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 of 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

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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.

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;\(^\text{11}\)
- 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.\(^\text{12}\)

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.\(^\text{13}\) 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?

\(^{11}\) HRS § 269-92.


• 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.\textsuperscript{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.\textsuperscript{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.\textsuperscript{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 20\textsuperscript{th} 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,\textsuperscript{17} and Hawaii Revised Statutes

\textsuperscript{14} Charles F. Phillips, Jr., The Regulation of Public Utilities 120 (Public Utilities Reports, Inc. 1988).

\textsuperscript{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.”)


\textsuperscript{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.

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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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.\textsuperscript{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.\textsuperscript{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 \textit{must} regulate investor owned utilities, \textit{may} regulate cooperatives,\textsuperscript{21} and \textit{may not} regulate municipal utilities.\textsuperscript{22}

- The PUC may review contracts between public utilities and "affiliated interests."\textsuperscript{23}

\textit{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."\textsuperscript{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.\textsuperscript{25}

\textsuperscript{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").

\textsuperscript{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.")

\textsuperscript{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.")

\textsuperscript{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.")

\textsuperscript{23} HRS § 269-19.5.

\textsuperscript{24} The relevant sections of the FPA are codified at 16 U. S. C. § 824 et seq.

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


\(^{27}\) 133 FERC ¶ 61,059 (2010).


transmission grids from utilities. 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. 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 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”).

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.” 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


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. 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.” 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. 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.” 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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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

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<td>Assumption of utility short-term and long-term responsibilities</td>
<td>Access to human resources&lt;br&gt;Infrastructure requirements&lt;br&gt;Institutional requirements&lt;br&gt;Business model compatibility&lt;br&gt;Stakeholder engagement and oversight&lt;br&gt;Potential for innovation&lt;br&gt;Potential for competition and efficient markets&lt;br&gt;Roles and incentive alignment&lt;br&gt;Context-specific factors (i.e. transactions, regulations)</td>
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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”).

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, prior experience and knowledge.

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.

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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.* 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.

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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. 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 decision making. 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.” 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:

- 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.” This guidance also will not legally control the decisions of the PUC regarding future public utility transfers, but it is highly


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.

• 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 Hawai‘i’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

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Categorization</th>
<th>Various Considerations</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Technical feasibility</strong>&lt;br&gt;Implications for the role and responsibilities of the utility</td>
<td></td>
<td>(+/-) No significant changes</td>
</tr>
<tr>
<td>Assumption of utility responsibilities</td>
<td>(+) Access to in-house staff and expertise</td>
<td></td>
</tr>
<tr>
<td>Achievement of State clean energy goals</td>
<td>(+/-) Subject to proposed transaction&lt;br&gt;(+/-) Subject to regulation&lt;br&gt;(-) Possibly incompatible business models&lt;br&gt;(-) Subject to shareholder control, not local stakeholders</td>
<td></td>
</tr>
<tr>
<td><strong>Financial feasibility</strong>&lt;br&gt;Impacts on ratepayers</td>
<td>(+) Rate moratoriums, freezes, or credits&lt;br&gt;(+/-) Potential financial impact of unregulated businesses&lt;br&gt;(-) For profit company with shareholder profit</td>
<td></td>
</tr>
<tr>
<td>Cost factors for initial acquisition</td>
<td>(+/-) Subject to the proposed transaction</td>
<td></td>
</tr>
<tr>
<td>Cost factors for achieving State clean energy goals</td>
<td>(+/-) Subject to the proposed transaction&lt;br&gt;(+/-) Broad access to capital, but not necessarily an increase&lt;br&gt;(+/-) Possible increase in credit rating of utility</td>
<td></td>
</tr>
<tr>
<td><strong>Legal feasibility</strong>&lt;br&gt;Existence of supporting framework</td>
<td>(+) Preexisting legal framework, although past decisions do not necessarily establish precedent</td>
<td></td>
</tr>
<tr>
<td>Governance requirements</td>
<td>(+) General IOU governance structure unchanged&lt;br&gt;(+/-) Potentially subject to PUC determination</td>
<td></td>
</tr>
<tr>
<td>Additional legal factors</td>
<td>(+/-) Subject to PUC approval</td>
<td></td>
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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.\textsuperscript{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

\textsuperscript{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. 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. 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.

*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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**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://lrbhawaii.hawaii.gov/con/conart7.html](http://lrbhawaii.hawaii.gov/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

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Categorization</th>
<th>Various Considerations</th>
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<tbody>
<tr>
<td>Technical feasibility</td>
<td>Implications for the role and responsibilities of the utility</td>
<td>(+/-) No significant changes</td>
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<tr>
<td></td>
<td>Assumption of utility responsibilities</td>
<td>(+/-) No significant changes</td>
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<tr>
<td></td>
<td>Achievement of State clean energy goals</td>
<td>(+/-) Subject to short-term decision-making</td>
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<td></td>
<td></td>
<td>(+) Increased local control</td>
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<td></td>
<td></td>
<td>(-) Misalignment of incentives and risk allocation</td>
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<tr>
<td></td>
<td></td>
<td>(-) Perception of inefficient and poor management</td>
</tr>
<tr>
<td>Financial feasibility</td>
<td>Impacts on ratepayers</td>
<td>(+/-) Subject to local priorities</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(+/-) Subject to government management</td>
</tr>
<tr>
<td></td>
<td>Cost factors for initial acquisition</td>
<td>(-) Increased public debt</td>
</tr>
<tr>
<td></td>
<td>Cost factors for achieving State clean energy goals</td>
<td>(+/-) Subject to the “friendliness” of transaction</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(+) Strong Hawaii credit rating</td>
</tr>
<tr>
<td>Legal feasibility</td>
<td>Existence of supporting framework</td>
<td>(-) Requires legislative chartering of a holding corporation</td>
</tr>
<tr>
<td></td>
<td>Governance requirements</td>
<td>(-) Requires substantial legislative bond issuance</td>
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<tr>
<td></td>
<td>Additional legal factors</td>
<td>(+/-) Unclear legal outlook</td>
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<tr>
<td></td>
<td></td>
<td>(+/-) Subject to determination of public/private role</td>
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<tr>
<td></td>
<td></td>
<td>(+/-) Subject to independence of holding company</td>
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<tr>
<td></td>
<td></td>
<td>(+/-) Subject to determination of civil service status for employees</td>
</tr>
</tbody>
</table>
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. 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.

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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.


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.

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.

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.

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. 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.

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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 Hawaii 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 Hawaii 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 waiver 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

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Categorization</th>
<th>Various Considerations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Implications for the role and responsibilities of the utility</td>
<td>(+/-) No significant changes</td>
<td>(+) Attractiveness of munis as employers</td>
</tr>
<tr>
<td>Assumption of utility responsibilities</td>
<td>(+) Integration with local government</td>
<td>(-) Possible disruption of workforce, but solutions possible</td>
</tr>
<tr>
<td>Achievement of State clean energy goals</td>
<td>(+/-) Subject to implementation and context</td>
<td>(+) Potential innovation due to lack of PUC regulation</td>
</tr>
<tr>
<td>Impacts on ratepayers</td>
<td>(+/-) Subject to the “friendliness” of transaction</td>
<td>(+) Increased responsiveness to local stakeholders</td>
</tr>
<tr>
<td>Cost factors for initial acquisition</td>
<td>(-) Increased public debt</td>
<td>(-) Perception of inefficient and poor management</td>
</tr>
<tr>
<td>Cost factors for achieving State clean energy goals</td>
<td>(+/-) Subject to the “friendliness” of transaction</td>
<td>(+) Strong county credit ratings</td>
</tr>
<tr>
<td>Existence of supporting framework</td>
<td>(+/-) Variety of legal acquisition pathways</td>
<td>(-) Requires county or referendum vote</td>
</tr>
<tr>
<td>Governance requirements</td>
<td>(+/-) Subject to context and goals</td>
<td>(+/-) The status or relevance of PUC oversight</td>
</tr>
<tr>
<td>Additional legal factors</td>
<td>(-) Requires county or referendum vote</td>
<td>(+/-) The status or relevance of PUC oversight</td>
</tr>
</tbody>
</table>

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, 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.


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,

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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. 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.

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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/](https://ilsr.org/just-how-democratic-are-rural-electric-cooperatives/)

### 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.

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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%. 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. 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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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.”

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.

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Categorization</th>
<th>Various Considerations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Technical feasibility</td>
<td>Implications for the role and responsibilities of the utility</td>
<td>(+/-) No significant changes</td>
</tr>
<tr>
<td></td>
<td>Assumption of utility responsibilities</td>
<td>(+) Access to support networks, (-) Possible disruption of the workforce</td>
</tr>
<tr>
<td></td>
<td>Achievement of State clean energy goals</td>
<td>(+/-) Subject to implementation and context, (+/-) Possibility of increased innovation (subject to PUC), (+) Increased responsiveness to local stakeholders</td>
</tr>
<tr>
<td>Financial feasibility</td>
<td>Impacts on ratepayers</td>
<td>(+/-) Subject to local priorities</td>
</tr>
<tr>
<td></td>
<td>Cost factors for initial acquisition</td>
<td>(+) Capital credits returned to customer-owners</td>
</tr>
<tr>
<td></td>
<td>Cost factors for achieving State clean energy goals</td>
<td>(+) Access to low-cost debt</td>
</tr>
<tr>
<td>Legal feasibility</td>
<td>Existence of supporting framework</td>
<td>(+) Pre-existing legal framework</td>
</tr>
<tr>
<td></td>
<td>Governance requirements</td>
<td>(+/-) Local governance through elections</td>
</tr>
<tr>
<td></td>
<td>Additional legal factors</td>
<td>(-) 20,000 population cap on RUS funding</td>
</tr>
<tr>
<td></td>
<td>Additional legal factors</td>
<td>(+/-) May or may not be subject to PUC regulation</td>
</tr>
</tbody>
</table>
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. 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.

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. 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.

- 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.

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

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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).
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.

\(^{70}\) 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,\(^7\) 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

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. 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%).

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”). 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. 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”, 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.

Furthermore, the State has enacted the Hawaii Ratepayer Protection Act, which was signed into law on April 24, 2018, and will take effect on July 1, 2018. The purpose of this act is to “is to


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.


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.”

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.

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?

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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.

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**Figure 7. Single Buyer: Feasibility Criteria Summary**

<table>
<thead>
<tr>
<th>Categorization</th>
<th>Various Considerations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Implications for the role and responsibilities of the utility</td>
<td>(+/-) Subject to realignment method (function unbundling, structural unbundling, independent entity)</td>
</tr>
<tr>
<td>Assumption of utility responsibilities</td>
<td>(+/-) No significant changes</td>
</tr>
<tr>
<td></td>
<td>(+) Realignment of utility incentives</td>
</tr>
<tr>
<td></td>
<td>(+) Possible greater innovative flexibility</td>
</tr>
<tr>
<td>Achievement of State clean energy goals</td>
<td>(+/-) Possible procurement efficiency improvement</td>
</tr>
<tr>
<td>Impact on ratepayers</td>
<td>(+/-) Depends on role provided to SB but most likely better terms since SB is independent</td>
</tr>
<tr>
<td>Cost factors for initial acquisition</td>
<td>(+/-) Requires some investments for ring-fencing mechanisms (for SB within the utility) or new capital expenses (for SB outside of the utility)</td>
</tr>
<tr>
<td>Cost factors for achieving State clean energy goals</td>
<td>(+) Realignment of utility incentives</td>
</tr>
<tr>
<td>Existence of supporting framework</td>
<td>(+/-) Existing framework, but requires significant additional regulatory or legislative reform</td>
</tr>
<tr>
<td>Governance requirements</td>
<td>(+/-) Requires independence from political and generation interests</td>
</tr>
<tr>
<td>Additional legal factors</td>
<td>Not applicable</td>
</tr>
</tbody>
</table>
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.

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.

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.

**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

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Categorization</th>
<th>Various Considerations</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Technical feasibility</strong></td>
<td>Implications for the role and responsibilities of the utility</td>
<td>(+/-) Separation of wires from generation</td>
</tr>
<tr>
<td></td>
<td>Assumption of utility responsibilities</td>
<td>(+/-) Subject to implementation</td>
</tr>
<tr>
<td></td>
<td>Achievement of State clean energy goals</td>
<td>(+/-) Subject to implementation</td>
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<tr>
<td><strong>Financial feasibility</strong></td>
<td>Impacts on ratepayers</td>
<td>(+) Possible value streams from DERs</td>
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<tr>
<td></td>
<td>Cost factors for initial acquisition</td>
<td>(-) Increased price volatility</td>
</tr>
<tr>
<td></td>
<td>Cost factors for achieving State clean energy goals</td>
<td>(+/-) Insufficient empirical data</td>
</tr>
<tr>
<td><strong>Legal feasibility</strong></td>
<td>Existence of supporting framework</td>
<td>(-) Requires significant regulatory changes</td>
</tr>
<tr>
<td></td>
<td>Governance requirements</td>
<td>(+/-) Must address conflicts of interest</td>
</tr>
<tr>
<td></td>
<td>Additional legal factors</td>
<td>Not applicable</td>
</tr>
</tbody>
</table>
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.  

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.

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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 Hawai‘i’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

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Categorization</th>
<th>Various Considerations</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Technical feasibility</strong></td>
<td>Implications for the role and responsibilities of the utility</td>
<td>(-) Undermines role of the utility</td>
</tr>
<tr>
<td></td>
<td>Assumption of utility responsibilities</td>
<td>(-) Unable to comply with reliability, adequacy, quality of service</td>
</tr>
<tr>
<td></td>
<td>Achievement of State clean energy goals</td>
<td>(-) Unable to achieve clean energy goals</td>
</tr>
<tr>
<td><strong>Financial feasibility</strong></td>
<td>Impacts on ratepayers</td>
<td>(-) Significant costs to lower income households</td>
</tr>
<tr>
<td></td>
<td>Cost factors for initial acquisition</td>
<td>(-) Rising electricity grid costs</td>
</tr>
<tr>
<td></td>
<td>Cost factors for achieving State clean energy goals</td>
<td>(-) Reduces revenue for investing into clean energy</td>
</tr>
<tr>
<td><strong>Legal feasibility</strong></td>
<td>Existence of supporting framework</td>
<td>(+) No significant legal impediments</td>
</tr>
<tr>
<td></td>
<td>Governance requirements</td>
<td>(+) Minimal governance concerns</td>
</tr>
<tr>
<td></td>
<td>Additional legal factors</td>
<td>Not applicable</td>
</tr>
</tbody>
</table>
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.
### Figure 10. Comprehensive Feasibility Assessment (1/2)

<table>
<thead>
<tr>
<th>Criteria</th>
<th>New Owner</th>
<th>Hybrid</th>
<th>Muni</th>
<th>Co-op</th>
</tr>
</thead>
<tbody>
<tr>
<td>Implications for the role and responsibilities of the utility</td>
<td>(+/-) No significant changes</td>
<td>(+/-) No significant changes</td>
<td>(+/-) No significant changes</td>
<td>(+/-) No significant changes</td>
</tr>
<tr>
<td>Assumption of utility responsibilities</td>
<td>(+) Access to in-house staff and expertise</td>
<td>(+/-) No significant changes</td>
<td>(+) Attractiveness of munis as employers</td>
<td>(+) Access to support networks</td>
</tr>
<tr>
<td>Technical feasibility</td>
<td>(+/-) Subject to implementation and context</td>
<td>(+/-) Subject to implementation and context</td>
<td>(+/-) Subject to implementation and context</td>
<td>(+/-) Subject to implementation and context</td>
</tr>
<tr>
<td>Achievement of State clean energy goals</td>
<td>(+/-) Subject to regulation</td>
<td>(+/-) Subject to regulation</td>
<td>(+/-) Subject to regulation</td>
<td>(+/-) Subject to regulation</td>
</tr>
<tr>
<td>Financial feasibility</td>
<td>(+) Rate moratoriums, freezes, or credits</td>
<td>(+/-) Subject to local priorities</td>
<td>(+/-) Subject to the &quot;friendliness&quot; of transaction</td>
<td>(+/-) Subject to local priorities</td>
</tr>
<tr>
<td>Cost factors for initial acquisition</td>
<td>(+/-) Subject to the proposed transaction</td>
<td>(+/-) Subject to the proposed transaction</td>
<td>(+/-) Subject to the proposed transaction</td>
<td>(+/-) Subject to the proposed transaction</td>
</tr>
<tr>
<td>Cost factors for achieving State clean energy goals</td>
<td>(+/-) Subject to the proposed transaction</td>
<td>(+/-) Subject to the proposed transaction</td>
<td>(+/-) Subject to the proposed transaction</td>
<td>(+/-) Subject to the proposed transaction</td>
</tr>
<tr>
<td>Legal feasibility</td>
<td>(+) Preexisting legal framework, although past decisions do not necessarily establish precedent</td>
<td>(+/-) Requires legislative chartering of a holding corporation</td>
<td>(+) Organization of legal acquisition pathways</td>
<td>(+) Pre-existing legal framework</td>
</tr>
<tr>
<td>Governance requirements</td>
<td>(+/-) Local government through elections</td>
<td>(+) Requires substantial legislative vote</td>
<td>(+/-) Requires county or referendum vote</td>
<td>(+/-) Requires municipal vote</td>
</tr>
<tr>
<td>Additional legal factors</td>
<td>(+/-) Subject to PUC approval</td>
<td>(+/-) Subject to determination of public/private role</td>
<td>(+/-) Subject to PUC determination</td>
<td>(+/-) Subject to PUC approval</td>
</tr>
</tbody>
</table>

*Criteria*: New Owner, Hybrid, Muni, Co-op
<table>
<thead>
<tr>
<th>Criteria</th>
<th>Single Buyer</th>
<th>IDER</th>
<th>Grid Defection</th>
</tr>
</thead>
<tbody>
<tr>
<td>Implications for the role and responsibilities of the utility</td>
<td>(+/-) Subject to realignment method (function unbundling, structural unbundling, independent entity)</td>
<td>(+/-) Separation of wires from generation</td>
<td>(-) Undermines role of the utility</td>
</tr>
<tr>
<td>Assumption of utility responsibilities</td>
<td>(+/-) No significant changes</td>
<td>(+/-) Subject to implementation</td>
<td>(-) Unable to comply with reliability, adequacy, quality of service</td>
</tr>
<tr>
<td>Achievement of State clean energy goals</td>
<td>(+) Realignment of utility incentives</td>
<td>(+/-) Subject to implementation</td>
<td>(-) Unable to achieve clean energy goals</td>
</tr>
<tr>
<td></td>
<td>(+) Possible greater innovative flexibility</td>
<td>(+) Possibility of increased competition</td>
<td></td>
</tr>
<tr>
<td></td>
<td>(+) Possible procurement efficiency improvement</td>
<td>(+) Possibility of increased innovation</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>(+) Increased responsiveness to local stakeholders</td>
<td></td>
</tr>
</tbody>
</table>

**Technical Feasibility**

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Single Buyer</th>
<th>IDER</th>
<th>Grid Defection</th>
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</thead>
<tbody>
<tr>
<td>Impacts on ratepayers</td>
<td>(+/-) Subject to realignment method</td>
<td>(+/-) Insufficient empirical data</td>
<td>(-) Significant costs to lower income households</td>
</tr>
<tr>
<td>Cost factors for initial acquisition</td>
<td>(+/-) Subject to realignment method</td>
<td>(+) Possible value streams from DERs</td>
<td>(-) Rising electricity grid costs</td>
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<tr>
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**Financial Feasibility**

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Single Buyer</th>
<th>IDER</th>
<th>Grid Defection</th>
</tr>
</thead>
<tbody>
<tr>
<td>Existence of supporting framework</td>
<td>(+/-) Existing framework, but requires significant additional regulatory or legislative reform</td>
<td>(+) Requires significant regulatory changes</td>
<td>(+) No significant legal impediments</td>
</tr>
<tr>
<td>Governance requirements</td>
<td>(+/-) Requires independence from political and generation interests</td>
<td>(+/-) Must address conflicts of interest</td>
<td>(+) Minimal governance concerns</td>
</tr>
<tr>
<td>Additional legal factors</td>
<td>Not applicable</td>
<td>Not applicable</td>
<td>Not applicable</td>
</tr>
</tbody>
</table>
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 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.

**Sources:**

B Lab, “What are B Corps,” available at: [http://www.bcorporation.net/what-are-b-corps](http://www.bcorporation.net/what-are-b-corps)


Green Mountain Power, “We are proud to be a Certified B Corp,” December 1, 2014, available at [https://www.greenmountainpower.com/2014/12/01/proud-certified-b-corporation/](https://www.greenmountainpower.com/2014/12/01/proud-certified-b-corporation/)
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.
15 Appendix D: List of works consulted


B Lab, “What are B Corps,” available at: http://www.bcorporation.net/what-are-b-corps


Green Mountain Power, “We are proud to be a Certified B Corp,” December 1, 2014, available at https://www.greenmountainpower.com/2014/12/01/proud-certified-b-corporation/


Hawaii Revised Statues, Title 15. Transportation and Utilities, Chapter 269, Section 269-16, “Merger and consolidation of public utilities.”


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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<table>
<thead>
<tr>
<th>Acronym</th>
<th>Full Form</th>
</tr>
</thead>
<tbody>
<tr>
<td>B-corp</td>
<td>B-corporation</td>
</tr>
<tr>
<td>Co-op</td>
<td>Cooperative</td>
</tr>
<tr>
<td>DBEDT</td>
<td>Department of Business, Economic Development &amp; Tourism</td>
</tr>
<tr>
<td>HECO</td>
<td>Hawaiian Electric Company</td>
</tr>
<tr>
<td>HEI</td>
<td>Hawaiian Electric Industries</td>
</tr>
<tr>
<td>HELCO</td>
<td>Hawaii Electric Light Company</td>
</tr>
<tr>
<td>IDER</td>
<td>Integrated Distributed Energy Resources</td>
</tr>
<tr>
<td>IOU</td>
<td>Investor-Owned Utility</td>
</tr>
<tr>
<td>IPP</td>
<td>Independent Power Producer</td>
</tr>
<tr>
<td>ISO</td>
<td>Independent System Operator</td>
</tr>
<tr>
<td>KIUC</td>
<td>Kauai Island Utility Cooperative</td>
</tr>
<tr>
<td>MECO</td>
<td>Maui Electric Company</td>
</tr>
<tr>
<td>Muni</td>
<td>Municipal Utility</td>
</tr>
<tr>
<td>OTEC</td>
<td>Ocean Thermal Energy Conversion</td>
</tr>
<tr>
<td>PPA</td>
<td>Power Purchase Agreement</td>
</tr>
<tr>
<td>PUC</td>
<td>Public Utilities Commission</td>
</tr>
<tr>
<td>PV</td>
<td>Photovoltaics</td>
</tr>
<tr>
<td>R&amp;D</td>
<td>Research and Development</td>
</tr>
</tbody>
</table>
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](image)

\(^{1}\) 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.

<table>
<thead>
<tr>
<th>Public Sector</th>
</tr>
</thead>
<tbody>
<tr>
<td>o DBEDT</td>
</tr>
<tr>
<td>o Consumer Advocate</td>
</tr>
<tr>
<td>o Public Utilities Commission (&quot;PUC&quot;)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>County Energy Coordinators</th>
</tr>
</thead>
<tbody>
<tr>
<td>o Hawaii</td>
</tr>
<tr>
<td>o Honolulu</td>
</tr>
<tr>
<td>o Maui</td>
</tr>
<tr>
<td>o Kauai</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>County Economic Development Boards</th>
</tr>
</thead>
<tbody>
<tr>
<td>o Hawaii</td>
</tr>
<tr>
<td>o Honolulu</td>
</tr>
<tr>
<td>o Maui</td>
</tr>
<tr>
<td>o Kauai</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Utilities</th>
</tr>
</thead>
<tbody>
<tr>
<td>o Hawaiian Electric Company (&quot;HECO&quot;)</td>
</tr>
<tr>
<td>o Hawaiian Electric Light Company (&quot;HELCO&quot;)</td>
</tr>
<tr>
<td>o Kauai Island Utility Cooperative (&quot;KIUC&quot;)</td>
</tr>
<tr>
<td>o Maui Electric Company (&quot;MECO&quot;)</td>
</tr>
</tbody>
</table>

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, nonprofits, 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

- **Project Kickoff**: May: Initial bilateral meetings with Core Group members
  June: VEBGE Workshop and bilateral meetings with various stakeholders
  July: Follow-on bilateral meetings with various stakeholders

- **Task 1.2.4: Ownership Model Stakeholder Outreach**: September: Identify and invite stakeholders to participate in the workshops; Convene Core Group
  October: Hold workshops on each island to discuss interim findings and solicit public input related to ownership model analysis; Convene Core Group

- **Task 1: Draft Report**: January-March: Provide Core Group with draft report of Task 1 for comment

- **Task 2.2.5: Regulatory Model Stakeholder Outreach**: January-February: Identify and invite stakeholders to participate in the workshops; Convene Core Group
  March: Finalize workshops
  April: Hold workshops on each island to discuss interim findings and solicit public input related to regulatory model analysis; Convene Core Group
  April-June: Convene Core Group
  September: Provide Core Group with draft report of Task 2 for comment

- **Task 2: Draft Report**: October-December: Convene Core Group; Public presentation of draft report; Incorporate comments and submit report to DBEDT for additional review
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

<table>
<thead>
<tr>
<th>Time</th>
<th>Topic Addressed</th>
<th>Overview</th>
</tr>
</thead>
<tbody>
<tr>
<td>5:30pm to 5:35pm</td>
<td>Arrival time</td>
<td>• Time for participants to take their seats and allow for late arrivals</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Invite participants to sign-in as they arrive</td>
</tr>
<tr>
<td>5:35pm to 5:40pm</td>
<td>Welcome, introductions, and icebreaker</td>
<td>• Project team welcomes the group and introduces themselves</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Participants are invited to introduce themselves</td>
</tr>
<tr>
<td>5:40pm to 5:55pm</td>
<td>Presentation Part I and Q&amp;A</td>
<td>• Share purpose of the workshop</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Review ground rules for discussion</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Utility overview presentation</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Q&amp;A as time allows</td>
</tr>
<tr>
<td>5:55pm to 6:15pm</td>
<td>Feedback on Stakeholder Priorities for their Utility</td>
<td>• Facilitated discussion to better understand stakeholder interests underlying their positions on ownership (e.g. more renewables, cost to customers, reliable electricity, etc.)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Questions:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>o What does your utility do well for you? For Hawaii?</td>
</tr>
<tr>
<td></td>
<td></td>
<td>o What else do you want to see from your utility that you don’t have now? For Hawaii?</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Pin board discussion and summarize results by theme at close of discussion.</td>
</tr>
<tr>
<td>6:15pm to 6:30pm</td>
<td>Presentation Part II: Utility Ownership Models</td>
<td>• Presentation on different utility ownership types and models (e.g. IOU, muni, and co-op), as well as what utilities can own.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Q&amp;A following the presentation as time allows.</td>
</tr>
<tr>
<td>Time</td>
<td>Topic Addressed</td>
<td>Overview</td>
</tr>
<tr>
<td>-----------------</td>
<td>-------------------------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>6:30pm to 6:55pm</td>
<td>Small Group Discussion</td>
<td>• 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.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Questions for discussion include:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>o What benefits do you see from each model?</td>
</tr>
<tr>
<td></td>
<td></td>
<td>o What drawbacks do you see from each model?</td>
</tr>
<tr>
<td></td>
<td></td>
<td>o What is accomplished by a change in utility ownership? Does it address your priorities?</td>
</tr>
<tr>
<td></td>
<td></td>
<td>o What are the key challenges to changing to this utility ownership model?</td>
</tr>
<tr>
<td>6:55pm to 7:00pm</td>
<td>Lightning Report-outs and Closing</td>
<td>• Small group facilitators provide lighting report-outs on key takeaways from their discussion.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Project team shares next steps for projects and thanks participants for coming.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Invite further input and questions in one-on-one discussions with team members following the workshop and/or to submit comments to the email.</td>
</tr>
<tr>
<td>7:00pm to 7:30pm</td>
<td>Follow-on Discussions</td>
<td>• The project team will remain onsite to allow for any follow-on discussions as needed.</td>
</tr>
</tbody>
</table>

**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. 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.
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. 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. 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 Hawai‘i and two on Oahu. Team 2 held one meeting on Maui, Molokai, Lanai, and Kauai, and joined Team 1 for the meeting in Honolulu.

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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

<table>
<thead>
<tr>
<th>Island</th>
<th>Town</th>
<th>Venue</th>
</tr>
</thead>
<tbody>
<tr>
<td>9-Oct</td>
<td>Hawaii Kona</td>
<td>Natural Energy Laboratory of Hawaii Authority</td>
</tr>
<tr>
<td>10-Oct</td>
<td>Hawaii Hilo</td>
<td>Waiakea High School</td>
</tr>
<tr>
<td>11-Oct</td>
<td>Oahu Waialua</td>
<td>Waialua High &amp; Intermediate School</td>
</tr>
<tr>
<td>12-Oct</td>
<td>Oahu Honolulu</td>
<td>No Workshop - Bilateral Meetings Only</td>
</tr>
<tr>
<td>13-Oct</td>
<td>Oahu Honolulu</td>
<td>Hawaiian Foreign Trade Zone</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Island</th>
<th>Town</th>
<th>Venue</th>
</tr>
</thead>
<tbody>
<tr>
<td>9-Oct</td>
<td>Maui Wailuku</td>
<td>Wailuku Community Center</td>
</tr>
<tr>
<td>10-Oct</td>
<td>Molokai Kaunakakai</td>
<td>Mitchell Pauole Main Hall</td>
</tr>
<tr>
<td>11-Oct</td>
<td>Lanai Lanai City</td>
<td>Lanai Community Center</td>
</tr>
<tr>
<td>12-Oct</td>
<td>Kauai Lihue</td>
<td>Chiefess Kamakahelei Middle School</td>
</tr>
<tr>
<td>13-Oct</td>
<td>Oahu Honolulu</td>
<td>Hawaiian Foreign Trade Zone</td>
</tr>
</tbody>
</table>

### 4.5 Outreach for Stakeholder Workshops

To announce the workshops and invite stakeholders, the Project Team 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 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:

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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/](http://dbedt.hawaii.gov/blog/17-55/).
## Figure 7. Media Outlets

<table>
<thead>
<tr>
<th>Island</th>
<th>Business or Organization</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Print, Online Media, and Local Business Groups</strong></td>
<td></td>
</tr>
<tr>
<td>Hawaii</td>
<td>Big Island News</td>
</tr>
<tr>
<td></td>
<td>Hawaii 24/7</td>
</tr>
<tr>
<td></td>
<td>Hawaii Island Chamber of Commerce</td>
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<tr>
<td></td>
<td>Hawaii Tribune Herald</td>
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<tr>
<td></td>
<td>Ililani Media</td>
</tr>
<tr>
<td></td>
<td>Konaweb Community Calendar</td>
</tr>
<tr>
<td></td>
<td>Leeward Planning Conference (calendar)</td>
</tr>
<tr>
<td></td>
<td>Rotary Club of Kona</td>
</tr>
<tr>
<td></td>
<td>Rotary Club of Kona Mauka</td>
</tr>
<tr>
<td></td>
<td>Rotary Club of Kona Sunrise</td>
</tr>
<tr>
<td></td>
<td>Rotary Club of North Hawaii</td>
</tr>
<tr>
<td></td>
<td>Rotary Club of Pahoa Sunset</td>
</tr>
<tr>
<td></td>
<td>Rotary Club of South Hilo</td>
</tr>
<tr>
<td></td>
<td>Rotary Club of Volcano</td>
</tr>
<tr>
<td></td>
<td>Rotary Club of Hilo Bay</td>
</tr>
<tr>
<td></td>
<td>West Hawaii Today</td>
</tr>
<tr>
<td>Oahu</td>
<td>Civil Beat</td>
</tr>
<tr>
<td></td>
<td>Green List Hawaii</td>
</tr>
<tr>
<td></td>
<td>Hawaii Business</td>
</tr>
<tr>
<td></td>
<td>Hawaii Chamber of Commerce</td>
</tr>
<tr>
<td></td>
<td>Hawaii Free Press (Statewide)</td>
</tr>
<tr>
<td></td>
<td>Hawaii Midweek Calendar (Statewide)</td>
</tr>
<tr>
<td></td>
<td>Hawaii Public Radio Events Calendar (Statewide)</td>
</tr>
<tr>
<td></td>
<td>Honolulu Star Advertiser (Statewide)</td>
</tr>
<tr>
<td></td>
<td>Kailua Chamber of Commerce</td>
</tr>
<tr>
<td></td>
<td>Midweek Oahu</td>
</tr>
<tr>
<td></td>
<td>Northshore Community Calendar (Chamber of Commerce)</td>
</tr>
<tr>
<td></td>
<td>Northshore News</td>
</tr>
<tr>
<td></td>
<td>Pacific Business Journal (Statewide)</td>
</tr>
<tr>
<td></td>
<td>Rotary Club of Hawaii Kai</td>
</tr>
<tr>
<td></td>
<td>Rotary Club of Honolulu</td>
</tr>
<tr>
<td></td>
<td>Rotary Club of Kahala Sunrise</td>
</tr>
<tr>
<td></td>
<td>Rotary Club of Kapolei Sunset</td>
</tr>
</tbody>
</table>
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. 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

<table>
<thead>
<tr>
<th>County (Town, Island)</th>
<th>Invitations Sent*</th>
<th>RSVPs**</th>
<th>Participants</th>
</tr>
</thead>
<tbody>
<tr>
<td>City and County of Honolulu</td>
<td>56</td>
<td>-</td>
<td>35</td>
</tr>
<tr>
<td>Honolulu, Oahu</td>
<td>-</td>
<td>34</td>
<td>29</td>
</tr>
<tr>
<td>Waialua, Oahu</td>
<td>-</td>
<td>7</td>
<td>6</td>
</tr>
<tr>
<td>Hawaii County</td>
<td>25</td>
<td>-</td>
<td>34</td>
</tr>
<tr>
<td>Hilo, Hawaii</td>
<td>-</td>
<td>12</td>
<td>14</td>
</tr>
<tr>
<td>Kona, Hawaii</td>
<td>-</td>
<td>7</td>
<td>20</td>
</tr>
<tr>
<td>Kauai County (Lihue)</td>
<td>19</td>
<td>17</td>
<td>27</td>
</tr>
<tr>
<td>Maui County</td>
<td>-</td>
<td>-</td>
<td>45</td>
</tr>
<tr>
<td>Lanai City, Lanai</td>
<td>2</td>
<td>14</td>
<td>18</td>
</tr>
<tr>
<td>Wailuku, Maui</td>
<td>15</td>
<td>19</td>
<td>19</td>
</tr>
<tr>
<td>Kaunakakai, Molokai</td>
<td>3</td>
<td>7</td>
<td>8</td>
</tr>
<tr>
<td>Statewide Organizations</td>
<td>6</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>TOTAL</td>
<td>126</td>
<td>117</td>
<td>141</td>
</tr>
</tbody>
</table>

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

- Honolulu, Oahu: 21%
- Lihue, Kauai: 19%
- Kona, Hawaii: 14%
- Hilo, Hawaii: 10%
- Wailuku, Molokai: 6%
- Waialua, Oahu: 4%
- Lanai City, Lanai: 13%
- Kona, Hawaii: 13%

Locations: Honolulu, Oahu; Lihue, Kauai; Kona, Hawaii; Hilo, Hawaii; Wailuku, Molokai; Lanai City, Lanai; Waialua, Oahu.
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

<table>
<thead>
<tr>
<th>Location</th>
<th>Top Priorities</th>
<th>Discussion Highlights by Model</th>
</tr>
</thead>
<tbody>
<tr>
<td>Honolulu</td>
<td>Local influence</td>
<td>IOU: Not aligned with public interest but with shareholders’ interest.</td>
</tr>
<tr>
<td></td>
<td>Innovation and flexibility</td>
<td>Muni: Potential for politicization of utility operations.</td>
</tr>
<tr>
<td></td>
<td>Distributed renewables</td>
<td>Co-op: Allows for local control.</td>
</tr>
<tr>
<td></td>
<td>Affordable rates and increased equity</td>
<td>Wires-Only: Encourage more competition and distributed energy.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>IOU: Concern about operational inefficiencies.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Muni: Could operate with less overhead.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Co-op: Difficult to educate and encourage active consumers.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Wires-Only: Might not work for population size and diversity on Oahu.</td>
</tr>
<tr>
<td>Waialua</td>
<td>Diverse energy generation, more renewables</td>
<td>IOU: Stable leadership and reliable service.</td>
</tr>
<tr>
<td></td>
<td>Resiliency</td>
<td>Muni: Too political.</td>
</tr>
<tr>
<td></td>
<td>Customer service</td>
<td>Co-op: Allows for consumer input.</td>
</tr>
<tr>
<td></td>
<td>Minimal bureaucracy</td>
<td>Wires-Only: Very interested in this model.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>IOU: Less competition for IPPs.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Muni: Equity concerns for rural areas.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Co-op: Difficult to ensure broad engagement.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Wires-Only: Likely to lower costs.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>IOU: Concerned about fit for Oahu.</td>
</tr>
</tbody>
</table>
Figure 11. Summary Table of Workshop Discussions: Hawaii County

<table>
<thead>
<tr>
<th>Location</th>
<th>Top Priorities</th>
<th>Discussion Highlights by Model</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>IOU</td>
</tr>
<tr>
<td><strong>Hilo</strong></td>
<td>Affordable rates and equitable access to renewables</td>
<td>Good access to resources</td>
</tr>
<tr>
<td></td>
<td>Innovation</td>
<td>Less investment in renewables</td>
</tr>
<tr>
<td></td>
<td>Local ownership</td>
<td>Profits go to off-island stakeholders</td>
</tr>
<tr>
<td></td>
<td>Utility-scale solar</td>
<td>High rates</td>
</tr>
<tr>
<td><strong>Kona</strong></td>
<td>Reliable service</td>
<td>Not aligned with community priorities</td>
</tr>
<tr>
<td></td>
<td>Renewable energy</td>
<td>Not as responsive to customer needs</td>
</tr>
<tr>
<td></td>
<td>Lower rates</td>
<td>Lack of innovation</td>
</tr>
<tr>
<td></td>
<td>Agile, innovative utility</td>
<td>Lack of local control</td>
</tr>
</tbody>
</table>
Figure 12. Summary Table of Workshop Discussions: Kauai County

<table>
<thead>
<tr>
<th>Location</th>
<th>Top Priorities</th>
<th>Discussion Highlights by Model</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>IOU</td>
</tr>
<tr>
<td>Lihue</td>
<td>Local control</td>
<td>Lack of local control</td>
</tr>
<tr>
<td></td>
<td>Efficient use of resources</td>
<td>No incentive to reduce expenses</td>
</tr>
<tr>
<td></td>
<td>Energy education (members and board)</td>
<td>Incentivized to increase capital investments</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Lack of interest in this model</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Local influence on decisions</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Influenced by politics</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Inefficient use of resources</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Concerned about fit for Kauai</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Works well for Kauai</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Democratically controlled</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Efficient use of resources</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Access to resources through co-op networks</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Low-cost financing options</td>
</tr>
<tr>
<td></td>
<td></td>
<td>PUC regulation hinders operations</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Did not discuss in detail</td>
</tr>
</tbody>
</table>

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Boston, MA 02111
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contact:
Sarah Booth
303-242-4154
sarah@boothcleanenergy.com
### Figure 13. Summary Table of Workshop Discussions: Maui County

<table>
<thead>
<tr>
<th>Location</th>
<th>Top Priorities</th>
<th>Discussion Highlights by Model</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lanai</td>
<td>Reliable, affordable electricity</td>
<td>IOU: Economies of scale</td>
</tr>
<tr>
<td></td>
<td>Local influence</td>
<td>Lack of local control and incorporating community needs</td>
</tr>
<tr>
<td></td>
<td>Responsiveness to community needs</td>
<td>IOU: Lack of local control and incorporating community needs</td>
</tr>
<tr>
<td></td>
<td>Planning for 100% renewables</td>
<td>IOU: Lower rates; not profit driven</td>
</tr>
<tr>
<td></td>
<td></td>
<td>IOU: Political influence and inefficient</td>
</tr>
<tr>
<td></td>
<td></td>
<td>IOU: Lack of interest in this model</td>
</tr>
</tbody>
</table>

Maui

<table>
<thead>
<tr>
<th>Top Priorities</th>
<th>Discussion Highlights by Model</th>
</tr>
</thead>
<tbody>
<tr>
<td>Local influence</td>
<td>IOU: Attract talented workforce</td>
</tr>
<tr>
<td>Reliable service</td>
<td>Muni: Political influence</td>
</tr>
<tr>
<td>Diverse fuel mix, more renewables, more distributed renewables</td>
<td>Co-op: County may lack the expertise to operate efficiently</td>
</tr>
<tr>
<td>Innovation</td>
<td>IOU: HECO Companies share resources</td>
</tr>
<tr>
<td>Resiliency</td>
<td>Muni: High cost to county to purchase a utility</td>
</tr>
<tr>
<td></td>
<td>Co-op: Local influence; incorporation of community needs</td>
</tr>
<tr>
<td></td>
<td>Wires-Only: Separation of generation and T&amp;D creates competition and lower rates</td>
</tr>
<tr>
<td></td>
<td>Forces utility to be more flexible</td>
</tr>
<tr>
<td></td>
<td>Interest in ISO</td>
</tr>
<tr>
<td></td>
<td>Co-op: Can be short-sighted if board members focused on reelection</td>
</tr>
<tr>
<td></td>
<td>Wires-Only: Questioned if Maui qualified for rural financing</td>
</tr>
<tr>
<td>Location</td>
<td>Top Priorities</td>
</tr>
<tr>
<td>----------</td>
<td>----------------------------------------</td>
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<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>Molokai</td>
<td>Safe and reliable service</td>
</tr>
<tr>
<td></td>
<td>Local influence</td>
</tr>
<tr>
<td></td>
<td>Transparency</td>
</tr>
<tr>
<td></td>
<td>Equity</td>
</tr>
<tr>
<td></td>
<td>Diverse energy mix</td>
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</tr>
</tbody>
</table>
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.
5.1.1.5 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.

5.1.1.6 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.
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.

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**Figure 14. Bilateral Meetings**

<table>
<thead>
<tr>
<th>Team 1</th>
<th>Island</th>
<th>Organization/Individual</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>9-Oct</td>
<td>Hawaii Island Economic Development Board</td>
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<tr>
<td></td>
<td></td>
<td>Paniolo Power</td>
</tr>
<tr>
<td></td>
<td>10-Oct</td>
<td>Hawaii County</td>
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<td></td>
<td></td>
<td>Hawaii Island Energy Cooperative</td>
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<td></td>
<td></td>
<td>HELCO leadership</td>
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<tr>
<td></td>
<td>11-Oct</td>
<td>Oahu</td>
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<tr>
<td></td>
<td></td>
<td>City and County of Honolulu</td>
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<tr>
<td></td>
<td></td>
<td>Oahu Economic Development Board</td>
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<tr>
<td></td>
<td>12-Oct</td>
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<td>Ulupono Initiative</td>
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<td>Independent Power Producer</td>
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<td></td>
<td>HECO Leadership</td>
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<td></td>
<td>13-Oct</td>
<td>Oahu</td>
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<td></td>
<td>Core Group Call</td>
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</table>

<table>
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<th>Team 2</th>
<th>Island</th>
<th>Organization/Individual</th>
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<tbody>
<tr>
<td></td>
<td>9-Oct</td>
<td>Maui</td>
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<tr>
<td></td>
<td></td>
<td>Mayor Arakawa, Maui County</td>
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<tr>
<td></td>
<td></td>
<td>Maui County</td>
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<tr>
<td></td>
<td></td>
<td>MECO Leadership</td>
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<tr>
<td></td>
<td>10-Oct</td>
<td>Molokai</td>
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<td>MECO Management for Molokai</td>
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<td>11-Oct</td>
<td>Lanai</td>
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<td>MECO Management for Lanai</td>
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<td>12-Oct</td>
<td>Kauai</td>
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<td>Kauai County</td>
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<td></td>
<td>Former PUC Commissioner</td>
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<td>KIUC</td>
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<td></td>
<td>13-Oct</td>
<td>Oahu</td>
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<td></td>
<td></td>
<td>Core Group Call</td>
</tr>
</tbody>
</table>

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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)
Figure 16. Utility Ownership Model Summary Handout (page 2)

Community Discussion on Utility Ownership Models
Workshop Handout

What does the Utility own?

- **Generation and Wires**
  - No Change: “Vertically Integrated” Utility that owns both power plants (generation), transmission, and distribution (wires).

- **Wires Only**
  - Utility only owns transmission and distribution (wires), with altered roles in power generation.

- **Single Buyer**
  - Either new contracting agency, or the utility (with regulatory protections), serves as a contracting agency for all generation in a technologically neutral fashion.

- **Integrated Distributed Energy Resource Operator**
  - The “utility” is required to provide open access to all distributed energy resources (“DERs”) connected to it at a price that recovers the utility’s costs. The utility or another entity coordinates flows across the grid.

- **Disperse Ownership**
  - Customers defect from the grid, passing costs onto other consumers, and decreasing system reliability.

Please do not hesitate to send any additional feedback to the following email address:
dbedt.utilitybizmodstudy@hawaii.gov
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

<table>
<thead>
<tr>
<th>Stakeholder Worksheet</th>
<th>Investor-Owned Utility (Shareholders own the utility)</th>
<th>Municipal Utility (The city/town government owns the utility)</th>
<th>Cooperative Utility (Customers own the utility)</th>
</tr>
</thead>
<tbody>
<tr>
<td>What benefits do you see from this model?</td>
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<td></td>
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<tr>
<td>What drawbacks do you see from this model?</td>
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<td></td>
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<tr>
<td>What is accomplished by this model of utility ownership?</td>
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<tr>
<td>Does it address your priorities?</td>
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<tr>
<td>What are the key challenges to changing to this utility ownership model?</td>
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<tr>
<td>Do you have any additional feedback, questions, or concerns?</td>
<td></td>
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</tbody>
</table>
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/8r0hnivy9lfih6ai/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/xzt8yhi2paf6dh1/Flier_Wailuku%20Community%20Center_10-9-17.pdf?dl=0
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](mailto:dbedt.utilitybizmodstudy@hawaii.gov). If you have questions about the meetings or project, please email them also at the same email address above.
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](#)

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](#)

Questions about the meeting or project can be directed to Len Trinidad, Project Manager, at [cherrylin@londoneconomics.com](mailto: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

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<tr>
<td>DBEDT</td>
<td>Hawaii Department of Business, Economic Development, and Tourism</td>
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<tr>
<td>DER</td>
<td>Distributed energy resource</td>
</tr>
<tr>
<td>FERC</td>
<td>Federal Energy Regulatory Commission</td>
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<td>HECO</td>
<td>Hawaiian Electric Company</td>
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<tr>
<td>HEI</td>
<td>Hawaiian Electric Industries</td>
</tr>
<tr>
<td>HELCO</td>
<td>Hawaii Electric Light Company</td>
</tr>
<tr>
<td>IDER</td>
<td>Integrated distributed energy resource</td>
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<tr>
<td>IOU</td>
<td>Investment owned utility</td>
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<tr>
<td>IPP</td>
<td>Independent power producer</td>
</tr>
<tr>
<td>ISO</td>
<td>Independent System Operator</td>
</tr>
<tr>
<td>KIUC</td>
<td>Kauai Island Utility Cooperative</td>
</tr>
<tr>
<td>LEI</td>
<td>London Economics International, LLC</td>
</tr>
<tr>
<td>MCG</td>
<td>Meister Consultants Group</td>
</tr>
<tr>
<td>MECO</td>
<td>Maui Electric Company</td>
</tr>
<tr>
<td>PUC</td>
<td>Public Utilities Commission</td>
</tr>
<tr>
<td>SB</td>
<td>Single Buyer</td>
</tr>
</tbody>
</table>
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)

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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.

\(^3\) 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.

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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

<table>
<thead>
<tr>
<th>Major Category</th>
<th>Minor Category</th>
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<tbody>
<tr>
<td>Support for State policy goals</td>
<td>Ability to meet state energy goals</td>
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<tr>
<td></td>
<td>Maximize consumer cost savings</td>
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<tr>
<td></td>
<td>Enable a competitive distribution system</td>
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<tr>
<td></td>
<td>Address conflicts of interest</td>
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<tr>
<td></td>
<td>Align stakeholder interests (responsiveness to local community)</td>
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<tr>
<td>Viability for utility finances</td>
<td>Access to capital</td>
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<tr>
<td>Implementation costs</td>
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<tr>
<td>Stability of rates</td>
<td>Likelihood of increased rate volatility</td>
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<tr>
<td>Operational risks</td>
<td>Reliability of service</td>
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<tr>
<td></td>
<td>Customer service quality</td>
</tr>
<tr>
<td></td>
<td>Staffing expertise adequacy (includes leadership)</td>
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<tr>
<td>Legal viability</td>
<td>Likelihood of changing legislation and regulations or additional legal require</td>
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<tr>
<td></td>
<td>Likelihood of legal challenges</td>
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</table>
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:  

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

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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.

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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. 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.”

- **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. 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.

- **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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• **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.

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

<table>
<thead>
<tr>
<th>Ranking</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>Incentivizes customer savings</td>
</tr>
<tr>
<td>Neutral</td>
<td>No discernable impact</td>
</tr>
<tr>
<td>Poor</td>
<td>Reduces consumer savings</td>
</tr>
</tbody>
</table>

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**

<table>
<thead>
<tr>
<th>Ranking</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>Encourages competition in energy services</td>
</tr>
<tr>
<td>Neutral</td>
<td>No discernable impact</td>
</tr>
<tr>
<td>Poor</td>
<td>Discourages competition in energy services</td>
</tr>
</tbody>
</table>

**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**

<table>
<thead>
<tr>
<th>Ranking</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>Separates conflicts of interest in planning and operational control from investment and ownership</td>
</tr>
<tr>
<td>Neutral</td>
<td>No discernable impact</td>
</tr>
<tr>
<td>Poor</td>
<td>Leads to conflicts of interest in planning and operational control with investment and ownership</td>
</tr>
</tbody>
</table>

**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

<table>
<thead>
<tr>
<th>Ranking</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>Aligns with interests of local stakeholders</td>
</tr>
<tr>
<td>Neutral</td>
<td>No discernable impact</td>
</tr>
<tr>
<td>Poor</td>
<td>Contravenes the interests of local stakeholders</td>
</tr>
</tbody>
</table>

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 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

<table>
<thead>
<tr>
<th>Ranking</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>Increases avenues and attractiveness to capital markets</td>
</tr>
<tr>
<td>Neutral</td>
<td>No discernable impact</td>
</tr>
<tr>
<td>Poor</td>
<td>Constrains avenues for capitalization</td>
</tr>
</tbody>
</table>
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. Moreover, 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**

<table>
<thead>
<tr>
<th>Ranking</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>Unique reductions in the cost of capital relative to the market rates of the status quo for incumbent utilities</td>
</tr>
<tr>
<td>Neutral</td>
<td>Rely primarily on status quo market rates</td>
</tr>
<tr>
<td>Poor</td>
<td>Unique risks or other major factors that raise the cost of capital</td>
</tr>
</tbody>
</table>

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**

<table>
<thead>
<tr>
<th>Ranking</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>Negligible costs from changes in ownership and operations</td>
</tr>
<tr>
<td>Neutral</td>
<td>Moderate costs of implementation from changes in ownership and operations</td>
</tr>
<tr>
<td>Poor</td>
<td>Major costs of implementation from changes in ownership and operations</td>
</tr>
</tbody>
</table>

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**

<table>
<thead>
<tr>
<th>Ranking</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>No need for any PUC oversight</td>
</tr>
<tr>
<td>Neutral</td>
<td>The required PUC oversight approximates the status quo</td>
</tr>
<tr>
<td>Poor</td>
<td>PUC oversight requirements significantly increase relative to status quo</td>
</tr>
</tbody>
</table>

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**

<table>
<thead>
<tr>
<th>Ranking</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>Reduces factors for potential rate volatility</td>
</tr>
<tr>
<td>Neutral</td>
<td>Approximates the status quo of regulated rates</td>
</tr>
<tr>
<td>Poor</td>
<td>Increases factors for potential rate volatility</td>
</tr>
</tbody>
</table>

**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

<table>
<thead>
<tr>
<th>Ranking</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>Improves the potential reliability of electricity service</td>
</tr>
<tr>
<td>Neutral</td>
<td>Maintains the reliability of service, with plausible assumptions and</td>
</tr>
<tr>
<td></td>
<td>considerations</td>
</tr>
<tr>
<td>Poor</td>
<td>Undermines the potential reliability of electricity service</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Ranking</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>Improves the ability of the utility to provide customer service</td>
</tr>
<tr>
<td>Neutral</td>
<td>Approximates the status quo of customer service</td>
</tr>
<tr>
<td>Poor</td>
<td>Reduces the ability of the utility to provide customer service</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Ranking</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>Preserves the expertise of staff</td>
</tr>
<tr>
<td>Neutral</td>
<td>Expertise can be maintained easily and sufficiently</td>
</tr>
<tr>
<td>Poor</td>
<td>Serious challenges in maintaining the expertise of staff</td>
</tr>
</tbody>
</table>

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**

<table>
<thead>
<tr>
<th>Ranking</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>Requires no regulatory or legislative action</td>
</tr>
<tr>
<td>Neutral</td>
<td>Requires regulatory action but no legislative action</td>
</tr>
<tr>
<td>Poor</td>
<td>Requires both regulatory and legislative action</td>
</tr>
</tbody>
</table>

**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**

<table>
<thead>
<tr>
<th>Ranking</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>Little risk of legal challenges from stakeholders</td>
</tr>
<tr>
<td>Neutral</td>
<td>Moderate risk of legal challenges from stakeholders</td>
</tr>
<tr>
<td>Poor</td>
<td>Major risk of legal challenges from stakeholders</td>
</tr>
</tbody>
</table>

**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.

<table>
<thead>
<tr>
<th>Major Category</th>
<th>Minor Category</th>
<th>Weight</th>
<th>IOU (status quo)</th>
<th>New Parent</th>
<th>Hybrid</th>
<th>Coop</th>
<th>Mani</th>
<th>IDER</th>
<th>Single Buyer</th>
<th>Grid Defection</th>
</tr>
</thead>
<tbody>
<tr>
<td>Support for State policy goals</td>
<td>Ability to meet state energy goals</td>
<td>10.0%</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>Maximize consumer cost savings</td>
<td>10.0%</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>3</td>
<td>3</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Enable a competitive distribution system</td>
<td>2.5%</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td>Address conflicts of interest</td>
<td>5.0%</td>
<td>1</td>
<td>1</td>
<td>2</td>
<td>1</td>
<td>3</td>
<td>3</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>Align stakeholder interests (responsiveness to local community)</td>
<td>10.0%</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>3</td>
<td>3</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Viability for utility finances</td>
<td>Access to capital</td>
<td>5.0%</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>3</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Costs of capital</td>
<td>5.0%</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>3</td>
<td>3</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Implementation costs</td>
<td>Likelihood to increase costs for change of ownership and operations</td>
<td>5.0%</td>
<td>3</td>
<td>1</td>
<td>2</td>
<td>1</td>
<td>2</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Likelihood to increase regulatory oversight requirements</td>
<td>5.0%</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>3</td>
<td>1</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Stability of rates</td>
<td>Likelihood of increased rate volatility</td>
<td>10.0%</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>Operational risks</td>
<td>Reliability of service</td>
<td>10.0%</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Customer service quality</td>
<td>2.5%</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Staffing expertise adequacy (includes leadership)</td>
<td>5.0%</td>
<td>3</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>1</td>
<td>2</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>Legal viability</td>
<td>Likelihood of changing legislation and regulations or additional legal</td>
<td>10.0%</td>
<td>3</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>1</td>
<td>2</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>requirements</td>
<td>5.0%</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>2</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Likelihood of legal challenges</td>
<td>5.0%</td>
<td>3</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>2</td>
<td>1</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>Summary of major categories</td>
<td>Support for state policy goals</td>
<td>37.5%</td>
<td>0.7</td>
<td>0.7</td>
<td>0.8</td>
<td>0.7</td>
<td>0.9</td>
<td>0.9</td>
<td>0.9</td>
<td>0.9</td>
</tr>
<tr>
<td></td>
<td>Viability for utility finances</td>
<td>10.0%</td>
<td>0.3</td>
<td>0.3</td>
<td>0.3</td>
<td>0.3</td>
<td>0.3</td>
<td>0.2</td>
<td>0.3</td>
<td>0.2</td>
</tr>
<tr>
<td></td>
<td>Implementation costs</td>
<td>10.0%</td>
<td>0.3</td>
<td>0.2</td>
<td>0.2</td>
<td>0.2</td>
<td>0.3</td>
<td>0.1</td>
<td>0.2</td>
<td>0.2</td>
</tr>
<tr>
<td></td>
<td>Stability of rates</td>
<td>10.0%</td>
<td>0.2</td>
<td>0.2</td>
<td>0.2</td>
<td>0.2</td>
<td>0.2</td>
<td>0.2</td>
<td>0.1</td>
<td>0.2</td>
</tr>
<tr>
<td></td>
<td>Operational risks</td>
<td>17.5%</td>
<td>0.4</td>
<td>0.4</td>
<td>0.4</td>
<td>0.4</td>
<td>0.3</td>
<td>0.3</td>
<td>0.4</td>
<td>0.3</td>
</tr>
<tr>
<td></td>
<td>Legal viability</td>
<td>15.0%</td>
<td>0.9</td>
<td>0.5</td>
<td>0.5</td>
<td>0.3</td>
<td>0.6</td>
<td>0.3</td>
<td>0.5</td>
<td>0.5</td>
</tr>
<tr>
<td>Combined Score</td>
<td>Score</td>
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Figure 4. Conclusions of the Ranking Analysis
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.
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


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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<tr>
<td>ASB</td>
<td>American Savings Bank</td>
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<tr>
<td>B</td>
<td>Billion</td>
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<tr>
<td>CEO</td>
<td>Chief Executive Officer</td>
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<tr>
<td>CFC</td>
<td>Cooperative Finance Corporation</td>
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<td>CY</td>
<td>Calendar Year</td>
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<td>D/E</td>
<td>Debt/equity ratio</td>
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<td>DBEDT</td>
<td>Department of Business Economic Development, and Tourism</td>
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<td>DCF</td>
<td>Discounted Cash Flow</td>
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<td>DER</td>
<td>Distributed Energy Resource</td>
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<td>D&amp;O</td>
<td>Decision &amp; Order</td>
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<td>EBITDA</td>
<td>Earnings Before Interest, Taxes, Depreciation and Amortization</td>
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<td>ECAC</td>
<td>Energy Cost Adjustment clause</td>
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<td>ECTSF</td>
<td>Electricity Conservation and Supply Task Force</td>
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<td>EPS</td>
<td>Earnings Per Share</td>
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<td>Enterprise Value</td>
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<td>Financial Accounting Standards Board</td>
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<td>FY</td>
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<td>GAAP</td>
<td>Generally Accepted Accounting Principles</td>
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<td>HAR</td>
<td>Hawaii Administrative Rules</td>
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<td>HB</td>
<td>House Bill</td>
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<td>HECO</td>
<td>Hawaii Electric Company</td>
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<td>Hawaii Electric Industries</td>
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<td>HELCO</td>
<td>Hawaii Electric Light Company</td>
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<td>HIEC</td>
<td>Hawaii Island Energy Cooperative</td>
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<tr>
<td>PURPA</td>
<td>Public Utility Regulatory Policies Act</td>
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<td>RE</td>
<td>Renewable energy</td>
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<td>Request for Proposals</td>
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<td>Rural Utilities Service</td>
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<td>Standard and Poor’s</td>
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<td>Trailing Twelve Months</td>
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<td>United States Code</td>
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<td>U.S. Department of Agriculture</td>
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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 feasibility 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

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\(^1\) 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\textsuperscript{2} (due to the possibility of retail and distribution competition), and medium-high probability of regulatory risk\textsuperscript{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\textsuperscript{4} and medium probability of labor availability risk\textsuperscript{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\textsuperscript{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

\textsuperscript{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.”

\textsuperscript{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.”

\textsuperscript{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.”

\textsuperscript{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.”

\textsuperscript{6} These conclusions do not apply to the case of Kauai since the incumbent utility on the island is already a Cooperative.
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.

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.
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\textsuperscript{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,\textsuperscript{8} with continued funding for the “inside” single buyer
through periodic evaluation in rate cases. However, there are likely to be a range of

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\textsuperscript{7} “Integrated Resource Planning” in this context is intended to also include the Power Supply Improvement Plan
processes.

\textsuperscript{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 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.²⁰

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.

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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,\textsuperscript{11} was contracted to perform this study.\textsuperscript{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\textsuperscript{13} listed in Figure 1.

![Figure 1. State’s key criteria for evaluating the models](image)

\textit{Source: Scope of Services under Contract No. 65595}

\textsuperscript{11} Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

\textsuperscript{12} Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

\textsuperscript{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.\textsuperscript{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.

\textsuperscript{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.\textsuperscript{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 \textit{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 \textit{costs of such a transition}, including both acquisition and non-acquisition costs incurred in the transition. The third are the \textit{legal changes necessary} to enable a change towards the ownership model. The fourth is an accounting and comparison of the \textit{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 \textbf{status quo} model (that is, an IOU in Honolulu, Hawaii, and Maui counties, and a co-op in Kauai county);
- A \textbf{Cooperative model} on each of the islands;
- A \textbf{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 \textit{external to the utility}; and
- A \textbf{single-buyer model} in which the single buyer is \textit{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:

- \textbf{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,

\textsuperscript{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. 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;

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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.

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. 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

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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


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](image)


### 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.


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

<table>
<thead>
<tr>
<th>Bundled Electric Utilities (2418 Utilities)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Publicly Traded and Investor-Owned (195 Utilities)</td>
</tr>
<tr>
<td>Comparable Sales (22 Utilities)</td>
</tr>
<tr>
<td>Comparable Ownership (9 Utilities)</td>
</tr>
<tr>
<td>Credit Rating (9 Utilities)</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Utility Name</th>
<th>Generation Capacity (MW)</th>
<th>2016 Sales (MWH)</th>
<th>Location</th>
<th>Credit Rating</th>
</tr>
</thead>
<tbody>
<tr>
<td>ALLETE, Inc.</td>
<td>1,932</td>
<td>9,002,262</td>
<td>WI, MN</td>
<td>A3</td>
</tr>
<tr>
<td>Alliant Energy Corp. (Wisconsin Power and Light)</td>
<td>2,481</td>
<td>10,874,507</td>
<td>WI</td>
<td>A2</td>
</tr>
<tr>
<td>Avista Corp.</td>
<td>1,862</td>
<td>8,509,330</td>
<td>MT, ID, WA</td>
<td>Baa1</td>
</tr>
<tr>
<td>El Paso Electric Co.</td>
<td>2,080</td>
<td>7,812,491</td>
<td>NM, TX</td>
<td>Baa1</td>
</tr>
<tr>
<td>Great Plains Energy, Inc. (Greater Missouri Operations Co.)</td>
<td>2,074</td>
<td>8,028,772</td>
<td>MO</td>
<td>Baa1</td>
</tr>
<tr>
<td>Northwestern Corp.</td>
<td>1,249</td>
<td>7,442,278</td>
<td>WY, SD, MT</td>
<td>A3</td>
</tr>
<tr>
<td>PNM Resources (Public Service Co. of NM)</td>
<td>2,481</td>
<td>8,951,524</td>
<td>NM</td>
<td>Baa3</td>
</tr>
<tr>
<td>Westar Energy Inc.</td>
<td>2,481</td>
<td>9,810,701</td>
<td>KS</td>
<td>Baa1</td>
</tr>
<tr>
<td>Wisconsin Energy Corp. (Wisconsin Public Service)</td>
<td>2,481</td>
<td>10,859,844</td>
<td>WI</td>
<td>A3</td>
</tr>
<tr>
<td>Hawaiian Electric Industries</td>
<td>1,669</td>
<td>8,845,335</td>
<td>HI</td>
<td>Baa2</td>
</tr>
</tbody>
</table>

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
### 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

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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.


Figure 6. Calculating the EPS, Equity Value, and Enterprise Value

Enterprise Value (EV) = Equity Value + Debt ($1.32 B) + Interest & Preferred Dividends ($23 MM) + Pension Liabilities ($600 MM) - Cash or Cash Equivalents ($74 MM)

Stock Price × Weighted Average of Diluted Shares Outstanding (108,665,000)

Price/Earnings (P/E) Ratio = Stock Price ÷ Earnings Per Share (EPS) ($1.12)

Net Income ($122 MM) ÷ Weighted Average of Diluted Shares Outstanding (108,665,000)

EBITDA ($474 MM) - Interest, taxes, depreciation, amortization (252 MM)

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 yield 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.

<table>
<thead>
<tr>
<th>Company</th>
<th>Trailing P/E Ratio</th>
<th>Enterprise Value</th>
<th>Equity Value</th>
<th>Per Share Valuation</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO</td>
<td>Median</td>
<td>$3,182 MM</td>
<td>$1,868 MM</td>
<td>$17.16</td>
</tr>
<tr>
<td></td>
<td>Mean</td>
<td>$3,179 MM</td>
<td>$1,865 MM</td>
<td>$17.13</td>
</tr>
<tr>
<td>HELCO</td>
<td>Median</td>
<td>$680 MM</td>
<td>$397 MM</td>
<td>$3.65</td>
</tr>
<tr>
<td></td>
<td>Mean</td>
<td>$679 MM</td>
<td>$397 MM</td>
<td>$3.64</td>
</tr>
<tr>
<td>MECO</td>
<td>Median</td>
<td>$666 MM</td>
<td>$395 MM</td>
<td>$3.63</td>
</tr>
<tr>
<td></td>
<td>Mean</td>
<td>$666 MM</td>
<td>$394 MM</td>
<td>$3.62</td>
</tr>
<tr>
<td>HECO Companies</td>
<td>Median</td>
<td>$4,528 MM</td>
<td>$2,661 MM</td>
<td>$24.44</td>
</tr>
<tr>
<td></td>
<td>Mean</td>
<td>$4,523 MM</td>
<td>$2,656 MM</td>
<td>$24.40</td>
</tr>
</tbody>
</table>

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).


Figure 8. Relative Contribution of HECO, HELCO, and MECO to HEI EPS

<table>
<thead>
<tr>
<th></th>
<th>2016</th>
<th>2015</th>
<th>2014</th>
<th>2013</th>
<th>2012</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO Companies</td>
<td>0.71</td>
<td>0.71</td>
<td>0.73</td>
<td>0.68</td>
<td>0.63</td>
<td>0.69</td>
</tr>
<tr>
<td>HECO</td>
<td>0.50</td>
<td>0.49</td>
<td>0.51</td>
<td>0.45</td>
<td>0.45</td>
<td>0.48</td>
</tr>
<tr>
<td>HELCO</td>
<td>0.11</td>
<td>0.11</td>
<td>0.10</td>
<td>0.11</td>
<td>0.10</td>
<td>0.11</td>
</tr>
<tr>
<td>MECO</td>
<td>0.11</td>
<td>0.11</td>
<td>0.12</td>
<td>0.12</td>
<td>0.08</td>
<td>0.11</td>
</tr>
<tr>
<td>American Savings Bank</td>
<td>0.29</td>
<td>0.29</td>
<td>0.27</td>
<td>0.32</td>
<td>0.37</td>
<td>0.31</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th></th>
<th>2016 EPS</th>
<th>Forward EPS (2018e)</th>
<th>Forward EPS (2019e)</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO Companies</td>
<td>$1.12</td>
<td>$1.08</td>
<td>$1.11</td>
</tr>
<tr>
<td>HECO</td>
<td>$0.79</td>
<td>$0.75</td>
<td>$0.77</td>
</tr>
<tr>
<td>HELCO</td>
<td>$0.17</td>
<td>$0.16</td>
<td>$0.17</td>
</tr>
<tr>
<td>MECO</td>
<td>$0.17</td>
<td>$0.17</td>
<td>$0.17</td>
</tr>
</tbody>
</table>

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)

<table>
<thead>
<tr>
<th></th>
<th>P/E Ratio (2018e)</th>
<th>Enterprise Value ($)</th>
<th>Equity Value ($)</th>
<th>Per Share Valuation</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO</td>
<td>Median</td>
<td>$2,928 MM</td>
<td>$1,614 MM</td>
<td>$14.83</td>
</tr>
<tr>
<td></td>
<td>Mean</td>
<td>$2,973 MM</td>
<td>$1,658 MM</td>
<td>$15.23</td>
</tr>
<tr>
<td>HELCO</td>
<td>Median</td>
<td>$637 MM</td>
<td>$355 MM</td>
<td>$3.26</td>
</tr>
<tr>
<td></td>
<td>Mean</td>
<td>$647 MM</td>
<td>$365 MM</td>
<td>$3.35</td>
</tr>
<tr>
<td>MECO</td>
<td>Median</td>
<td>$629 MM</td>
<td>$358 MM</td>
<td>$3.29</td>
</tr>
<tr>
<td></td>
<td>Mean</td>
<td>$639 MM</td>
<td>$368 MM</td>
<td>$3.38</td>
</tr>
<tr>
<td>HECO Companies</td>
<td>Median</td>
<td>$4,195 MM</td>
<td>$2,327 MM</td>
<td>$21.38</td>
</tr>
<tr>
<td></td>
<td>Mean</td>
<td>$4,258 MM</td>
<td>$2,391 MM</td>
<td>$21.96</td>
</tr>
</tbody>
</table>

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.

<table>
<thead>
<tr>
<th>Company</th>
<th>P/E Ratio (2019e)</th>
<th>Enterprise Value</th>
<th>Equity Value</th>
<th>Per Share Valuation</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO</td>
<td>Median</td>
<td>$2,866 MM</td>
<td>$1,551 MM</td>
<td>$14.25</td>
</tr>
<tr>
<td></td>
<td>Mean</td>
<td>$2,887 MM</td>
<td>$1,573 MM</td>
<td>$14.45</td>
</tr>
<tr>
<td>HELCO</td>
<td>Median</td>
<td>$624 MM</td>
<td>$341 MM</td>
<td>$3.14</td>
</tr>
<tr>
<td></td>
<td>Mean</td>
<td>$628 MM</td>
<td>$346 MM</td>
<td>$3.18</td>
</tr>
<tr>
<td>MECO</td>
<td>Median</td>
<td>$615 MM</td>
<td>$344 MM</td>
<td>$3.16</td>
</tr>
<tr>
<td></td>
<td>Mean</td>
<td>$620 MM</td>
<td>$349 MM</td>
<td>$3.20</td>
</tr>
<tr>
<td>HECO Companies</td>
<td>Median</td>
<td>$4,104 MM</td>
<td>$2,237 MM</td>
<td>$20.55</td>
</tr>
<tr>
<td></td>
<td>Mean</td>
<td>$4,135 MM</td>
<td>$2,267 MM</td>
<td>$20.83</td>
</tr>
</tbody>
</table>

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.

4.1.1.3 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. For EBITDA, this analysis deducts $16.3 million for corporate-level expenses, resulting in an adjusted EBITDA of $474 million. The median CY16 EV/EBITDA ratio of 10.6 from the trading comps yields an equivalent EV of $4.9 billion. 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. 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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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).

<table>
<thead>
<tr>
<th>Company</th>
<th>EBITDA</th>
<th>EV/EBITDA Ratio</th>
<th>Enterprise Value</th>
<th>Equity Value</th>
<th>Per Share Valuation</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO</td>
<td>$335 MM</td>
<td>Median</td>
<td>$3,351 MM</td>
<td>$2,037 MM</td>
<td>$18.71</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Mean</td>
<td>$3,400 MM</td>
<td>$2,086 MM</td>
<td>$19.16</td>
</tr>
<tr>
<td>HELCO</td>
<td>$85 MM</td>
<td>Median</td>
<td>$849 MM</td>
<td>$567 MM</td>
<td>$5.21</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Mean</td>
<td>$862 MM</td>
<td>$580 MM</td>
<td>$5.52</td>
</tr>
<tr>
<td>MECO</td>
<td>$69 MM</td>
<td>Median</td>
<td>$692 MM</td>
<td>$421 MM</td>
<td>$3.87</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Mean</td>
<td>$702 MM</td>
<td>$431 MM</td>
<td>$3.96</td>
</tr>
<tr>
<td>HECO Companies</td>
<td>$490 MM</td>
<td>Median</td>
<td>$4,892 MM</td>
<td>$3,024 MM</td>
<td>$27.78</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Mean</td>
<td>$4,963 MM</td>
<td>$3,096 MM</td>
<td>$28.44</td>
</tr>
</tbody>
</table>

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.

4.1.1.4 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%.

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.

<table>
<thead>
<tr>
<th></th>
<th>Average Enterprise Value</th>
<th>Average Equity Value</th>
<th>Average Cost Per Share</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO</td>
<td>$3,082 MM</td>
<td>$1,768 MM</td>
<td>$16.24</td>
</tr>
<tr>
<td>HELCO</td>
<td>$697 MM</td>
<td>$415 MM</td>
<td>$3.81</td>
</tr>
<tr>
<td>MECO</td>
<td>$651 MM</td>
<td>$380 MM</td>
<td>$3.49</td>
</tr>
<tr>
<td>HECO Companies</td>
<td>$4,430 MM</td>
<td>$2,562 MM</td>
<td>$23.54</td>
</tr>
</tbody>
</table>

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.

<table>
<thead>
<tr>
<th>Target Company</th>
<th>Acquiring Company</th>
<th>Effective Date</th>
<th>EV (Deal Value)</th>
<th>EV/TTM EBITDA</th>
<th>Equity Value/TTM Net Income</th>
</tr>
</thead>
<tbody>
<tr>
<td>Empire District Electric Co</td>
<td>Liberty Utilities Co</td>
<td>1-Jan-17</td>
<td>$2.4 B</td>
<td>10.8</td>
<td>26.3</td>
</tr>
<tr>
<td>TECO Energy Inc</td>
<td>Emera Inc</td>
<td>1-Jul-16</td>
<td>$10.4 B</td>
<td>11.6</td>
<td>71.2</td>
</tr>
<tr>
<td>UIL Holdings Corp</td>
<td>Iberdrola USA Inc</td>
<td>16-Dec-15</td>
<td>$4.7 B</td>
<td>11.4</td>
<td>27.2</td>
</tr>
<tr>
<td>Cleco Corp</td>
<td>Investor Group</td>
<td>13-Apr-16</td>
<td>$4.7 B</td>
<td>10.3</td>
<td>21.1</td>
</tr>
<tr>
<td>Integrys Energy Group Inc</td>
<td>Wisconsin Energy Corp</td>
<td>29-Jun-15</td>
<td>$9.1 B</td>
<td>11.3</td>
<td>18.0</td>
</tr>
<tr>
<td>Peepo Holdings Inc</td>
<td>Exelon Corp</td>
<td>23-Mar-16</td>
<td>$12.2 B</td>
<td>7.7</td>
<td>23.3</td>
</tr>
<tr>
<td>UNS Energy Corp</td>
<td>Fortis Inc</td>
<td>15-Aug-14</td>
<td>$4.5 B</td>
<td>9.2</td>
<td>18.1</td>
</tr>
<tr>
<td>NV Energy Inc</td>
<td>MidAmerican Energy Holdings Co</td>
<td>19-Dec-13</td>
<td>$10.4 B</td>
<td>10.3</td>
<td>16.9</td>
</tr>
<tr>
<td>CH Energy Group Inc</td>
<td>Cascade Acquisition Sub Inc</td>
<td>27-Jun-13</td>
<td>$1.5 B</td>
<td>10.4</td>
<td>20.9</td>
</tr>
<tr>
<td><strong>Median</strong></td>
<td></td>
<td></td>
<td>10.4</td>
<td></td>
<td>21.1</td>
</tr>
<tr>
<td><strong>Mean</strong></td>
<td></td>
<td></td>
<td>10.3</td>
<td></td>
<td>27.0</td>
</tr>
</tbody>
</table>

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)**
<table>
<thead>
<tr>
<th>Company</th>
<th>EV/TTM EBITDA</th>
<th>Enterprise Value</th>
<th>Equity Value</th>
<th>Per Share Valuation</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO</td>
<td>Median</td>
<td>$3,380 MM</td>
<td>$2,066 MM</td>
<td>$18.98</td>
</tr>
<tr>
<td></td>
<td>Mean</td>
<td>$3,354 MM</td>
<td>$2,040 MM</td>
<td>$18.74</td>
</tr>
<tr>
<td>HELCO</td>
<td>Median</td>
<td>$857 MM</td>
<td>$575 MM</td>
<td>$5.28</td>
</tr>
<tr>
<td></td>
<td>Mean</td>
<td>$850 MM</td>
<td>$568 MM</td>
<td>$5.22</td>
</tr>
<tr>
<td>MECO</td>
<td>Median</td>
<td>$698 MM</td>
<td>$427 MM</td>
<td>$3.92</td>
</tr>
<tr>
<td></td>
<td>Mean</td>
<td>$698 MM</td>
<td>$427 MM</td>
<td>$3.92</td>
</tr>
<tr>
<td>HECO Companies</td>
<td>Median</td>
<td>$4,934 MM</td>
<td>$3,067 MM</td>
<td>$28.17</td>
</tr>
<tr>
<td></td>
<td>Mean</td>
<td>$4,896 MM</td>
<td>$3,029 MM</td>
<td>$27.82</td>
</tr>
</tbody>
</table>

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. 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)

<table>
<thead>
<tr>
<th>Company</th>
<th>Equity Value/TTM Net Income</th>
<th>Enterprise Value</th>
<th>Equity Value</th>
<th>Per Share Valuation</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO</td>
<td>Median</td>
<td>$3,117 MM</td>
<td>$1,803 MM</td>
<td>$16.56</td>
</tr>
<tr>
<td></td>
<td>Mean</td>
<td>$3,623 MM</td>
<td>$2,308 MM</td>
<td>$21.20</td>
</tr>
<tr>
<td>HELCO</td>
<td>Median</td>
<td>$666 MM</td>
<td>$384 MM</td>
<td>$3.52</td>
</tr>
<tr>
<td></td>
<td>Mean</td>
<td>$773 MM</td>
<td>$491 MM</td>
<td>$4.51</td>
</tr>
<tr>
<td>MECO</td>
<td>Median</td>
<td>$653 MM</td>
<td>$381 MM</td>
<td>$3.50</td>
</tr>
<tr>
<td></td>
<td>Mean</td>
<td>$759 MM</td>
<td>$488 MM</td>
<td>$4.49</td>
</tr>
<tr>
<td>HECO Companies</td>
<td>Median</td>
<td>$4,436 MM</td>
<td>$2,568 MM</td>
<td>$23.59</td>
</tr>
<tr>
<td></td>
<td>Mean</td>
<td>$5,155 MM</td>
<td>$3,288 MM</td>
<td>$30.20</td>
</tr>
</tbody>
</table>

4.1.1.2.3 Results of Comparative Transactions Approach

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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

<table>
<thead>
<tr>
<th></th>
<th>Average EV</th>
<th>Average Equity Valuation</th>
<th>Average Cost per Share</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO</td>
<td>$3,249 MM</td>
<td>$1,935 MM</td>
<td>$17.77</td>
</tr>
<tr>
<td>HELCO</td>
<td>$761 MM</td>
<td>$479 MM</td>
<td>$4.40</td>
</tr>
<tr>
<td>MECO</td>
<td>$675 MM</td>
<td>$404 MM</td>
<td>$3.71</td>
</tr>
<tr>
<td><strong>HECO Companies</strong></td>
<td><strong>$4,685 MM</strong></td>
<td><strong>$2,817 MM</strong></td>
<td><strong>$25.88</strong></td>
</tr>
</tbody>
</table>

#### 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.\footnote{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.} 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.
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.  

- 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.

- 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.

- 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.

- 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.

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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transaction, its legal and regulatory challenges, billing practices of retained entities, and other considerations.

<table>
<thead>
<tr>
<th>Target</th>
<th>Acquiror</th>
<th>Transaction Value</th>
<th>Transaction Cost</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Citizens Communications</td>
<td>Kauai Island Utility Cooperative</td>
<td>$215 MM</td>
<td>$3 MM</td>
<td>1.16%</td>
</tr>
<tr>
<td>CH Energy Group</td>
<td>Fortis Inc.</td>
<td>$1,500 MM</td>
<td>$15 MM</td>
<td>1.00%</td>
</tr>
<tr>
<td>NSTAR</td>
<td>Northeast Utilities</td>
<td>$4,170 MM</td>
<td>$68 MM</td>
<td>1.63%</td>
</tr>
<tr>
<td>Energy East</td>
<td>Ibredola</td>
<td>$4,500 MM</td>
<td>$24 MM</td>
<td>0.53%</td>
</tr>
<tr>
<td>Aquila</td>
<td>Great Plains Energy</td>
<td>$1,700 MM</td>
<td>$65 MM</td>
<td>3.82%</td>
</tr>
<tr>
<td>Median</td>
<td></td>
<td></td>
<td></td>
<td>1.16%</td>
</tr>
<tr>
<td>Average</td>
<td></td>
<td></td>
<td></td>
<td>1.63%</td>
</tr>
</tbody>
</table>

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.
<table>
<thead>
<tr>
<th>Methodology</th>
<th>Low EV</th>
<th>High EV</th>
<th>Low $/Share</th>
<th>High $/Share</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO</td>
<td>$2,866 MM</td>
<td>$3,380 MM</td>
<td>$14.25</td>
<td>$18.98</td>
</tr>
<tr>
<td>HELCO</td>
<td>$624 MM</td>
<td>$857 MM</td>
<td>$3.14</td>
<td>$5.28</td>
</tr>
<tr>
<td>MECO</td>
<td>$615 MM</td>
<td>$698 MM</td>
<td>$3.16</td>
<td>$5.28</td>
</tr>
<tr>
<td><strong>HECO Companies</strong></td>
<td><strong>$4,104 MM</strong></td>
<td><strong>$4,934 MM</strong></td>
<td><strong>$20.55</strong></td>
<td><strong>$28.17</strong></td>
</tr>
</tbody>
</table>

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, 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

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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. 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. 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**

| Steps                        | Months | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 |
|------------------------------|--------|---|---|---|---|---|---|---|---|---|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|
| **Phase 1 Establishment**   |        |   |   |   |   |   |   |   |   |   |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |
| Initial Leadership and Stakeholder Discussion | Low   |   |   |   |   |   |   |   |   |   |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |
| Formation of Provisional Committee | Low   |   |   |   |   |   |   |   |   |   |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |
| Survey of Local Population | Low/Medium |   |   |   |   |   |   |   |   |   |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |
| Formation of Steering Committee | Low/Medium |   |   |   |   |   |   |   |   |   |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |
| Incorporation and Bylaws | Low |   |   |   |   |   |   |   |   |   |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |
| Membership Recruitment Campaign | Medium |   |   |   |   |   |   |   |   |   |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |
| Founding Assembly and Board Election | Low |   |   |   |   |   |   |   |   |   |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |
| **Phase 2 Purchase**        |        |   |   |   |   |   |   |   |   |   |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |
| Feasibility Study and Financial Analysis | Medium |   |   |   |   |   |   |   |   |   |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |
| Fund, Negotiate, Purchase Assets | High |   |   |   |   |   |   |   |   |   |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |
| **Phase 3 Regulatory Approval** |        |   |   |   |   |   |   |   |   |   |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |
| Legal Outreach | High |   |   |   |   |   |   |   |   |   |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |
| Regulatory Approval | High |   |   |   |   |   |   |   |   |   |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |
| **Phase 4 Operation**       |        |   |   |   |   |   |   |   |   |   |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |
| Transition of Workforce | High |   |   |   |   |   |   |   |   |   |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |
| Commence Operations | High |   |   |   |   |   |   |   |   |   |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |    |

*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:

- 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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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. 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.


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. 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 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;


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. 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:

- **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.

• **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 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. 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,

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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. In contrast, the Bylaws can be substantially more elaborate than the statutory language.

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Box 2. Legal Requirements: Articles of Incorporation

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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

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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.\textsuperscript{58} Some of the provisions contained in the KIUC bylaws cover the following:\textsuperscript{59}

- \textit{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.\textsuperscript{60}

- \textit{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.\textsuperscript{61}

- \textit{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).\textsuperscript{62}

- \textit{Quorum requirements}, which outline how many members or Board members are necessary to generate a vote at one of the meetings.\textsuperscript{63}

- \textit{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.\textsuperscript{64}

- \textit{Officer requirements}, including their election, removal, duties, compensation, and responsibilities.\textsuperscript{65}


\textsuperscript{59} Id.

\textsuperscript{60} See Article I of the \textit{Seventh A&R Bylaws of KIUC}.

\textsuperscript{61} Article II of the \textit{Seventh A&R Bylaws of KIUC}.

\textsuperscript{62} Id.

\textsuperscript{63} Id.

\textsuperscript{64} Article III of the \textit{Seventh A&R Bylaws of KIUC}.

\textsuperscript{65} Article V of the \textit{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. 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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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. 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. However, as with all special purpose bonds, there is a political condition...

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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/](http://budget.hawaii.gov/budget/about-budget/state-debt/).

-- a two-thirds vote of the members of each house of the Legislature must authorize the use of special purpose revenue bonds.  

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. 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

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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.


### 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:

- **Application.** In its application, the applicants will typically outline the background of the applicants, envisioned benefits from the Change in Control, commitments to community

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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 intervene75 or participate without intervention76 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 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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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 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, 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

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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,\(^1\) 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

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\(^1\) 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](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. 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.”

The case further outlined the principles of a Cooperative as follows:

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.”

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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.")


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.”

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). According to HRS § 269-31(c), the co-op must be:

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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-

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, which exempts them from federal income tax. 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. However, Cooperatives do not have to deduct the costs of goods sold from gross sales to calculate the 85-percent member income test. 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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95 Internal Revenue Manuals, Part 7, 7.25.12, Organizations Exempt Under IRC 501(c)(12).
income falls below the 85-percent threshold, the organization is no longer exempt and must file a corporate tax return.\textsuperscript{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.\textsuperscript{99} The IRS also clarified that qualified co-op entities could potentially exclude income from qualified pole rentals.\textsuperscript{100} Government grants from either state or federal agencies may also be excluded as income, provided that such grants meet certain requirements.\textsuperscript{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.\textsuperscript{102}

With regards to the \textbf{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.\textsuperscript{103} Note that these requirements generally comport with the requirements present in the HRS, Chapter 421C. These requirements include:

\begin{itemize}
  \item Adequate records of each member’s rights and interests in its assets;
\end{itemize}

\begin{flushright}


\textsuperscript{100} IRC Section 501(c)(12)(B)(ii) and (C)(i).

\textsuperscript{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.


\textsuperscript{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;\textsuperscript{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;\textsuperscript{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;\textsuperscript{106}

• The sale of propane by trucks.\textsuperscript{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.


\textsuperscript{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).


\textsuperscript{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. 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. 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, 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.” 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.” 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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109 Population of these islands are all greater than 20,000. See www.census.gov.

110 7 CFR 1710.2, emphasis added.


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.

<table>
<thead>
<tr>
<th>Box 5. Required Findings for RUS Electric Loans</th>
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<tbody>
<tr>
<td>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.</td>
</tr>
<tr>
<td>1. <strong>Area Coverage</strong>: The borrower must provide adequate electricity service to the widest practical number of rural users during the life of the loan;</td>
</tr>
<tr>
<td>2. <strong>Feasibility</strong>: 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;</td>
</tr>
<tr>
<td>3. <strong>Security</strong>: 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;</td>
</tr>
<tr>
<td>4. <strong>Interim Financing</strong>: If RUS funding will be replacing interim funding, there must be satisfactory evidence that the funding was used for its intended purpose;</td>
</tr>
<tr>
<td>5. <strong>Facilities for non-rural areas</strong>: 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;</td>
</tr>
<tr>
<td>6. <strong>Facilities to be included in the rate base</strong>: 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.</td>
</tr>
</tbody>
</table>

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. 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.\textsuperscript{114}

Lobbying: Borrowers must comply with relevant restrictions on lobbying activities;\textsuperscript{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.

\begin{footnotesize}
\begin{itemize}
  \item \textsuperscript{115} 7 CFR 3018.
\end{itemize}
\end{footnotesize}
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. 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.” However, the approach for applying these two standards has transformed since the KIUC acquisition. 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.

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.” 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.

In the case of the NextEra Merger, the procedure was a “contested case” procedures under HRS, Chapter 91. The PUC held proceedings pursuant to those procedures, in which the PUC stated


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.\textsuperscript{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.\textsuperscript{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.

<table>
<thead>
<tr>
<th>Box 6. The Regulatory Procedure for the KIUC Acquisition</th>
</tr>
</thead>
<tbody>
<tr>
<td>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:\textsuperscript{125}</td>
</tr>
</tbody>
</table>

\textsuperscript{123} See Order No. 33041, Order Establishing Forma Evidentiary Hearing Dates and Location, filed in Dkt No 2015-0022, on August 4, 2015.

\textsuperscript{124} HRS § 91-9.

\textsuperscript{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.

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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.
<table>
<thead>
<tr>
<th>Dates</th>
<th>Actions</th>
</tr>
</thead>
<tbody>
<tr>
<td>1/29/15</td>
<td>Application filed by HECO and NextEra</td>
</tr>
<tr>
<td>3/2/15</td>
<td>Commission issues Order No. 32695, initiating the instant proceeding, establishing standards of review, an initial statement of issues and initial procedures</td>
</tr>
<tr>
<td>3/19/15</td>
<td>Commission issues Order No. 32726, which governs the classification, acquisition, and use of trade secrets, and other confidential information</td>
</tr>
<tr>
<td>4/1/15</td>
<td>Commission also issues Order No. 32739, &quot;Establishing Issues and Initial Procedural Schedule, and Addressing Related Matters.&quot;</td>
</tr>
<tr>
<td>4/13/15</td>
<td>Deadline for the Direct Testimony of Applicants</td>
</tr>
<tr>
<td>7/20/15</td>
<td>Deadline for Answer and Direct Testimony of Intervenors</td>
</tr>
<tr>
<td>8/10/15</td>
<td>Deadline for answering and testimonies for the Consumer Advocate</td>
</tr>
<tr>
<td>8/31/15</td>
<td>Deadline for Responsive Testimony by Applicants Limited to Responding To Answering and Direct Testimony by Intervenors and Consumer Advocate</td>
</tr>
<tr>
<td>9/11/15</td>
<td>Commission issues Order No. 33116, &quot;Establishing dates for additional pre-filed testimony and modifying certain procedural dates,&quot; which set forth additions and modifications to the current procedural schedule</td>
</tr>
<tr>
<td>9/30/15</td>
<td>Deadline for discovery</td>
</tr>
<tr>
<td>10/7/15</td>
<td>Deadline for rebuttal testimony from consumer advocate and intervenors</td>
</tr>
<tr>
<td>10/20/15</td>
<td>Deadline for all procedural motions</td>
</tr>
<tr>
<td>10/30/15</td>
<td>Commission issues Order No. 33296, &quot;Addressing the four procedural motions filed on October 20, 2015&quot;</td>
</tr>
<tr>
<td>11/6/15</td>
<td>Parties filed their final lists of pre-filed testimony and exhibits with the commission</td>
</tr>
<tr>
<td>11/30</td>
<td>12/16</td>
</tr>
<tr>
<td>1/4/16</td>
<td>Commission issues Order No. 33429, which established further procedures, in addition to other steps</td>
</tr>
<tr>
<td>1/13/2016-1/29/16</td>
<td>Deadlines for the consumer advocate and intervening parties to issue IRs to applicants and DOD regarding the new and modified commitments, responses and rebuttals</td>
</tr>
<tr>
<td>2/1/16</td>
<td>Evidentiary hearings</td>
</tr>
<tr>
<td>3/7/16</td>
<td>Commissions issues Order No. 33570, outlining the deadline dates and procedures to govern the post-evidentiary phase</td>
</tr>
<tr>
<td>3/31/16</td>
<td>Deadline for post-evidentiary briefs</td>
</tr>
<tr>
<td>7/15/2016</td>
<td>Decision and Order, &quot;Dismissing application without Prejudice and Closing Docket.&quot;</td>
</tr>
</tbody>
</table>

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 underlying 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

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.\textsuperscript{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,”\textsuperscript{135} whereas in the KIUC case, it was followed by “to perform the services currently offered by the utility to be acquired.”\textsuperscript{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.\textsuperscript{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.\textsuperscript{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.

\textbf{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

\textsuperscript{134} Id. at 18.

\textsuperscript{135} Order No. 33795 at 249.

\textsuperscript{136} KIUC D&O at 6.

\textsuperscript{137} Order No. 33795 at 254.

\textsuperscript{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.\textsuperscript{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.\textsuperscript{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;

\textsuperscript{139} KIUC D&O at 19-20.

\textsuperscript{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), 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. 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

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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

\(^{143}\) 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.\(^\text{151}\) Such an entity is not a “public utility” that may be regulated by the PUC.\(^\text{152}\)

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.\(^\text{153}\) Since then, generally, KIUC has still been regulated by the PUC, and as discussed above, the PUC has statutory authority to do so.\(^\text{154}\) However, KIUC regulation has been relaxed in certain respects; for example, KIUC is not required to undergo the Power Supply Improvement Process or the

\(^{151}\) *In Re Puuawaawaa 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. 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. 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). 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 and required to participate in the Distributed Energy Resource docket. 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. 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-191 to 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 for procuring energy from independent power producers (“IPPs”) and Public Utility Regulatory Policies Act (“PURPA”) 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”), suggesting that the HECO

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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 underserved 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.

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.

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. 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 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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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


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. 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).

### Table: 2005 Up-Front Capital Costs and Operating Costs of the OPA

<table>
<thead>
<tr>
<th>Category</th>
<th>Cost (CAD $2005)</th>
<th>Cost (USD $2017)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Up-front Capital Costs</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Furniture and equipment</td>
<td>$1,174,275</td>
<td>$1,718,093</td>
</tr>
<tr>
<td>Leasehold improvements</td>
<td>$1,458,998</td>
<td>$2,134,674</td>
</tr>
<tr>
<td>Computer hardware and software</td>
<td>$ 693,839</td>
<td>$ 1,015,163</td>
</tr>
<tr>
<td>Audio visual equipment</td>
<td>$ 135,843</td>
<td>$ 198,753</td>
</tr>
<tr>
<td>Telephone system</td>
<td>$  49,217</td>
<td>$  72,010</td>
</tr>
<tr>
<td><strong>Total Up-front Capital Costs</strong></td>
<td>$3,512,172</td>
<td>$5,138,694</td>
</tr>
<tr>
<td><strong>General Operating Costs</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>General program costs</td>
<td>$ 536,662</td>
<td>$ 785,195</td>
</tr>
<tr>
<td>Information technology</td>
<td>$ 101,175</td>
<td>$ 148,030</td>
</tr>
<tr>
<td>Premises</td>
<td>$ 551,474</td>
<td>$ 806,867</td>
</tr>
<tr>
<td>Office and administration</td>
<td>$ 494,483</td>
<td>$ 723,483</td>
</tr>
<tr>
<td>Bank interest</td>
<td>$  15,287</td>
<td>$  22,367</td>
</tr>
<tr>
<td><strong>Personnel Costs</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Staff and board costs</td>
<td>$ 5,929,823</td>
<td>$ 8,675,983</td>
</tr>
<tr>
<td>Professional and consulting fees</td>
<td>$ 6,274,558</td>
<td>$ 9,180,368</td>
</tr>
<tr>
<td><strong>Total Operating Costs</strong></td>
<td>$13,903,462</td>
<td>$20,342,293</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$17,415,634</td>
<td>$25,480,987</td>
</tr>
</tbody>
</table>

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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.
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

<table>
<thead>
<tr>
<th>Time Period</th>
<th>Resource Type</th>
<th>Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020-2025</td>
<td>Wind</td>
<td>149</td>
</tr>
<tr>
<td></td>
<td>Grid Scale PV</td>
<td>580</td>
</tr>
<tr>
<td></td>
<td>Batteries</td>
<td>179</td>
</tr>
<tr>
<td></td>
<td>Geothermal</td>
<td>20</td>
</tr>
<tr>
<td></td>
<td>CC</td>
<td>151</td>
</tr>
<tr>
<td></td>
<td>Other</td>
<td>192</td>
</tr>
<tr>
<td>2026-2030</td>
<td>Wind</td>
<td>20</td>
</tr>
<tr>
<td></td>
<td>Grid Scale PV</td>
<td>160</td>
</tr>
<tr>
<td></td>
<td>Batteries</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Geothermal</td>
<td>60</td>
</tr>
<tr>
<td></td>
<td>CC</td>
<td>302</td>
</tr>
<tr>
<td></td>
<td>Other</td>
<td>20</td>
</tr>
<tr>
<td>2031-2035</td>
<td>Wind</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Grid Scale PV</td>
<td>100</td>
</tr>
<tr>
<td></td>
<td>Batteries</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Geothermal</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>CC</td>
<td>302</td>
</tr>
<tr>
<td></td>
<td>Other</td>
<td>0</td>
</tr>
<tr>
<td>2036-2040</td>
<td>Wind</td>
<td>400</td>
</tr>
<tr>
<td></td>
<td>Grid Scale PV</td>
<td>100</td>
</tr>
<tr>
<td></td>
<td>Batteries</td>
<td>30</td>
</tr>
<tr>
<td></td>
<td>Geothermal</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>CC</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Other</td>
<td>40</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>2805</strong></td>
</tr>
</tbody>
</table>


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. On the other hand, the costs of information

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technology, computers, and audio/visual items have declined over time since 2005. 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

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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

<table>
<thead>
<tr>
<th>Steps</th>
<th>Cost Level</th>
</tr>
</thead>
<tbody>
<tr>
<td>Preliminary Discussions and Analysis</td>
<td>Low</td>
</tr>
<tr>
<td>Initiate Studies to Determine and Evaluate Key Characterisit</td>
<td>Uncertain</td>
</tr>
<tr>
<td>Legislative Enactment</td>
<td>Medium</td>
</tr>
<tr>
<td>PUC Proceedings (&quot;Outside&quot;)</td>
<td>Uncertain</td>
</tr>
<tr>
<td>Puc Proceedings (&quot;Inside&quot;)</td>
<td>Uncertain</td>
</tr>
<tr>
<td>Incorporate, Establish Bylaws, and Draft Rules</td>
<td>Uncertain</td>
</tr>
<tr>
<td>Staff the Single Buyer</td>
<td>High</td>
</tr>
<tr>
<td>Organizational and Operational Transformation</td>
<td>High</td>
</tr>
<tr>
<td>Establish and Refine Planning Processes</td>
<td>High</td>
</tr>
<tr>
<td>Establish and Refine Procurement Processes</td>
<td>High</td>
</tr>
<tr>
<td>Commence Operations</td>
<td>High</td>
</tr>
</tbody>
</table>

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, and there are ongoing proceedings regarding procurement of renewable generation in Docket No. 2017-0352. 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.”


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 expedited 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.

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.”

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.


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). 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

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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.

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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 undertake 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. 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...
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. 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.”

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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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.


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\textsuperscript{186} (or future evolved planning framework\textsuperscript{187}), and the HECO Companies’ Codes of Conduct,\textsuperscript{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.\textsuperscript{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.


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

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\(^{190}\) 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 184 above. 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.  

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**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.

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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


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.\footnote{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.\footnote{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.\footnote{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

\footnote{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.

\footnote{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.


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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.  

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• 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.

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Box 14. Required Capabilities for Bid Evaluation

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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*

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\(^{200}\) 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 processes202 and has begun to evaluate the utilities’ Integrated Grid Planning

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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. 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.


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. 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. 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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Subsequently, the commission opened a docket to investigate Integrated Grid Planning and reaffirmed suspension of the IRP framework requirements for the HECO companies.\textsuperscript{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.

\textsuperscript{207} \textit{Id.}, at 12-13.

\textsuperscript{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 and procurement of the generation capacity

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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 planning211 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

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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. 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.

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• Inclusion of provisions on price and quality, electric service, state goals, or other community goals.

These are some of the potential reasons to amend 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.

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.

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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.


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.\(^{217}\)

\(^{214}\) 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.\textsuperscript{218} Except where the legislature has expressly granted jurisdiction or responsibility in certain matters,\textsuperscript{219} the PUC’s authority and general investigative power is limited to public utilities.\textsuperscript{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

\begin{enumerate}
\item 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.”\textsuperscript{217}
\end{enumerate}

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.\textsuperscript{218}

\begin{enumerate}
\item See, e.g., HRS § 269-122(b) (extending the PUC’s regulatory authority to the public benefits fee administrator).\textsuperscript{219}
\item 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.”).\textsuperscript{220}
\end{enumerate}
express legislative mandate, such as community-based renewable energy. Even with legislative action, if there is no mandate, the PUC may not take action.

As with the “outside” single buyer, if the “inside” single buyer is created as a separate legal entity from the franchised utility, 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. 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; 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.”

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


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. 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, 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. 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

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.”

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. 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.

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-


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.”

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.”

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.


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. 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. 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.

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/](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

239 HRS § 103D-102(a).

240 HRS § 269-122


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. 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.

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;

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.

• 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. 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. The framework for Integrated Resource Planning...
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. The proposed IGP process is presented in HECO’s Integrated Grid Planning Report, dated March 1, 2018.

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. The IRP Framework required this Independent Entity to have no conflicts of interests and to be impartial. 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.


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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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. 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

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).\textsuperscript{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.\textsuperscript{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

\textsuperscript{254} HEI 2016 Fiscal Year Form 10K

\textsuperscript{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

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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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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. 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

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.

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. 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.

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.

260 See the regulatory proceedings for the NextEra merger (Applicants’ Response to LOL-IR-38, Docket No. 2015-022).

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 Hawai‘i’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\textsuperscript{262} and RPI-X\textsuperscript{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.

\textsuperscript{262} In the RPI-X regulatory scheme, utilities that can achieve greater levels of operational efficiency are rewarded with higher rates of return.

\textsuperscript{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, 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**

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

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out the functions of the single buyer. However, we expect that a utility-based single 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 EPA268 regardless of the utility model. The State renewable energy target is a significant mitigation strategy to reduce the environmental impact of utilities.

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/150096268.PDF?O=PDF&T=&Y=&D=&FID=150096268&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 is the primary relevant metric.
The volatile price of oil is a major challenge for Hawai‘i’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

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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](https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RWTC&f=A)


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](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

<table>
<thead>
<tr>
<th>Category</th>
<th>Risk</th>
<th>Impact Rating</th>
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<th>Coop</th>
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<tr>
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<td>Legal</td>
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<td>M</td>
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<td>M</td>
</tr>
</tbody>
</table>

**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


Bronski et al., The Economics of Grid Defection (2014). Available at: https://rmi.org/insights/reports/economics-grid-defection/


Code of Federal Regulations (multiple chapters)


Etter Grain Company, Inc. v. United States, 462 F.2d 259, 263 (5th Cir. 1972).


Hawaii Administrative Rules (multiple chapters)


Hawaii Public Utilities Commission, Decision and Order No. 19658, Docket No. 02-0060, issued September 17, 2002 (Herein referred to as the “KIUC D&O”).


Hawaii Revised Statues (multiple chapters)


Internal Revenue Code / Revenue Rulings (multiple chapters)

Internal Revenue Manuals, Part 7, 7.25.12, Organizations Exempt Under IRC 501(c)(12).


U.S. Code (multiple chapters)

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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<table>
<thead>
<tr>
<th>Acronym</th>
<th>Full form</th>
</tr>
</thead>
<tbody>
<tr>
<td>AUC</td>
<td>Alberta Utilities Commission</td>
</tr>
<tr>
<td>CUB</td>
<td>Citizens Utility Board</td>
</tr>
<tr>
<td>DBEDT</td>
<td>Hawaii Department of Business Economic Development and Tourism</td>
</tr>
<tr>
<td>DBF</td>
<td>Department of Budget &amp; Finance</td>
</tr>
<tr>
<td>DCA</td>
<td>Division of Consumer Advocacy</td>
</tr>
<tr>
<td>DCCA</td>
<td>Department of Commerce and Consumer Affairs</td>
</tr>
<tr>
<td>DERs</td>
<td>Distributed energy resources</td>
</tr>
<tr>
<td>DPS</td>
<td>Department of Public Service</td>
</tr>
<tr>
<td>DSPP</td>
<td>Distributed System Platform Provider</td>
</tr>
<tr>
<td>EIMA</td>
<td>Energy Infrastructure Modernization Act</td>
</tr>
<tr>
<td>FTE</td>
<td>Full-time equivalent</td>
</tr>
<tr>
<td>GEMA</td>
<td>Gas and Electricity Markets Authority</td>
</tr>
<tr>
<td>HECO</td>
<td>Hawaiian Electric Company</td>
</tr>
<tr>
<td>HELCO</td>
<td>Hawaii Electric Light Company</td>
</tr>
<tr>
<td>IGO</td>
<td>Integrated Grid Operator</td>
</tr>
<tr>
<td>IPART</td>
<td>Independent Pricing and Regional Tribunal</td>
</tr>
<tr>
<td>KIUC</td>
<td>Kauai Island Utility Cooperative</td>
</tr>
<tr>
<td>LEI</td>
<td>London Economics International LLC</td>
</tr>
<tr>
<td>MECO</td>
<td>Maui Electric Company</td>
</tr>
<tr>
<td>NASUCA</td>
<td>National Association of State Utility Consumer Advocates</td>
</tr>
<tr>
<td>NER</td>
<td>National Electricity Rules</td>
</tr>
<tr>
<td>NSW</td>
<td>New South Wales</td>
</tr>
<tr>
<td>NY PSC</td>
<td>New York Public Service Commission</td>
</tr>
<tr>
<td>OCC</td>
<td>Office of Consumer Counsel</td>
</tr>
<tr>
<td>OEB</td>
<td>Ontario Energy Board</td>
</tr>
<tr>
<td>Ofgem</td>
<td>Office of Gas and Electricity Markets</td>
</tr>
<tr>
<td>PPAs</td>
<td>Power purchase agreements</td>
</tr>
<tr>
<td>PUC</td>
<td>Public Utilities Commission</td>
</tr>
<tr>
<td>REV</td>
<td>Reforming the Energy Vision</td>
</tr>
<tr>
<td>RIIO</td>
<td>Revenue = Incentives + Innovation + Outputs</td>
</tr>
<tr>
<td>RPS</td>
<td>Renewable Portfolio Standards</td>
</tr>
<tr>
<td>RRFE</td>
<td>Renewed Regulatory Framework for Electricity</td>
</tr>
<tr>
<td>ST</td>
<td>Suruhanjaya Tenaga</td>
</tr>
<tr>
<td>TNB</td>
<td>Tenaga Nasional Berhad</td>
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<td>UCA</td>
<td>Office of the Utilities Consumer Advocate</td>
</tr>
<tr>
<td>UCB</td>
<td>Utility Consumers' Board</td>
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<tr>
<td>UK</td>
<td>United Kingdom</td>
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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 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 model1. 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.

<table>
<thead>
<tr>
<th>Achieve State energy goals</th>
<th>Maximize consumer cost savings</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs</td>
<td>Eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation</td>
</tr>
</tbody>
</table>

**Figure 1. State's key criteria in evaluating the models**

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).


\(^6\) 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.

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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.

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](source)

<table>
<thead>
<tr>
<th>Divisions</th>
<th>Approximate # of Staff</th>
<th>Major background/expertise of Staff</th>
</tr>
</thead>
<tbody>
<tr>
<td>Office of the Commissioners</td>
<td>7</td>
<td>management, development, administration</td>
</tr>
<tr>
<td>Commission Counsel</td>
<td>11</td>
<td>legal advisory</td>
</tr>
<tr>
<td>Audit Section</td>
<td>4</td>
<td>auditing, research, analysis</td>
</tr>
<tr>
<td>Engineering Section</td>
<td>4</td>
<td>engineering, analysis</td>
</tr>
<tr>
<td>Consumer Affairs and Compliance</td>
<td>9</td>
<td>public relations, complaint resolution</td>
</tr>
<tr>
<td>Administrative Support Services</td>
<td>10</td>
<td>documentation, clerical services, information technology, coordination</td>
</tr>
<tr>
<td>Fiscal Section</td>
<td>3</td>
<td>fiscal and procurement</td>
</tr>
<tr>
<td>Personnel Section</td>
<td>2</td>
<td>recruitment, human resources</td>
</tr>
<tr>
<td>Policy and Research</td>
<td>15</td>
<td>analysis, economics, research</td>
</tr>
</tbody>
</table>

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


\(^11\) Ibid, page 5.


“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

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15 Ibid.
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,


21 Section 26-34 of the Hawaii Revised Statutes.


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](image)


### 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. 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." The names of these offices vary in different states, including "People’s Counsel, Public Counsel, Consumer Advocate, and Consumer Counsel." 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.” The Office of Consumer Counsel ("OCC") under the Department of Regulatory Agencies serves as the consumer advocate office in Colorado. The OCC was created

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26 Ibid.

27 Ibid.

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


30 Ibid.


32 Ibid.

33 Ibid.

34 Ibid.


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.” ⁴⁸ 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. ⁴⁹ In another word, for every dollar the OCC spent (including the management and staffing expenditures), Colorado consumers saved $66 in total. ⁵⁰

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

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⁵⁰ 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. 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](image)

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.”

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.” 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


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).

<table>
<thead>
<tr>
<th>Number of staff: 100,000 customers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Status quo</td>
</tr>
<tr>
<td>HI</td>
</tr>
<tr>
<td>---</td>
</tr>
<tr>
<td>12.8</td>
</tr>
</tbody>
</table>

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.


5.2.1.1 PUC

United Kingdom

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44 Ibid, page 2.
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). This is significantly more employees than that of both the OEB and the Hawaii PUC.

### Figure 8. Ofgem organizational chart (post-structural reorganization)

<table>
<thead>
<tr>
<th>Divisions</th>
<th>Function</th>
</tr>
</thead>
<tbody>
<tr>
<td>Consumers and Markets</td>
<td>Looks after the interests of consumers in the energy market (wholesale and retail markets, enforcement)</td>
</tr>
<tr>
<td>System Operation and Networks</td>
<td>Focused on price controls (resources will particularly focus on the next round due to start in 2021) and ensuring maximum consumer benefits</td>
</tr>
<tr>
<td>Corporate &amp; Scheme Services</td>
<td>Provides business support services and runs environmental schemes for Government</td>
</tr>
</tbody>
</table>

Note: The above divisions are for both the gas and electricity markets, and thus is representative of Ofgem as a whole.


Ofgem underwent organizational restructuring in April 2018, reducing the number of divisions from seven to three to “better focus on protecting consumers.” 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

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49 Staffing levels post-organizational restructuring are lower than that of 2016 (i.e., 834 FTEs).


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.


<table>
<thead>
<tr>
<th>Divisions</th>
<th>Approximate # of Staff</th>
<th>Major background/expertise of Staff</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulatory</td>
<td>366</td>
<td>policy advisory, planning, administration</td>
</tr>
<tr>
<td>E-Serve</td>
<td>241</td>
<td>management, administration, development &amp; implementation, operations</td>
</tr>
<tr>
<td>Corporate Services</td>
<td>117</td>
<td>management, budgets, risk management, finance, accounting, procurement</td>
</tr>
</tbody>
</table>

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.


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). 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

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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.\textsuperscript{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.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure10.png}
\caption{Ofgem’s staffing levels before and after implementation of the RIIO model}
\end{figure}

\textbf{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\textsuperscript{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.\textsuperscript{56}

\textsuperscript{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.)

\textsuperscript{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.

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

![OEB Organizational Chart]

Figure 12. Divisions in OEB and major background/expertise of corresponding division’s staff

<table>
<thead>
<tr>
<th>Divisions</th>
<th>Major background/expertise of Staff</th>
</tr>
</thead>
<tbody>
<tr>
<td>Management Committee</td>
<td>management, executive assistance</td>
</tr>
<tr>
<td>Chief Operating Officer &amp; General Counsel</td>
<td>policy advisory, executive assistance</td>
</tr>
<tr>
<td>Governance &amp; Administration</td>
<td>executive assistance, administration</td>
</tr>
<tr>
<td>Strategic Policy</td>
<td>strategic and policy advisory, risk management, business planning, executive assistance</td>
</tr>
<tr>
<td>Public Affairs</td>
<td>communications, media relations, stakeholder engagement, brand management</td>
</tr>
<tr>
<td>Legal Services</td>
<td>legal, strategic, and policy advisory, executive assistance</td>
</tr>
<tr>
<td>Consumer Protection &amp; Industry Performance</td>
<td>management, customer assistance, auditing, licensing, compliance &amp; enforcement</td>
</tr>
<tr>
<td>Applications</td>
<td>rates regulation, management, policy advisory</td>
</tr>
<tr>
<td>People, Culture &amp; Business Solutions</td>
<td>human resources, finance, information technology, organizational development, procurement, facilities</td>
</tr>
<tr>
<td>Registrar</td>
<td>management, administration, policy advisory</td>
</tr>
</tbody>
</table>

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 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](image)

Note: The above staffing levels are based on “budgeted 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.

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


Canada, and advocates for the Charter of International Consumer Rights. 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. 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.

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
As an example of Conventional PBR, Alberta uses the I-X approach, 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.

<table>
<thead>
<tr>
<th>Number of staff: 100,000 customers</th>
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</thead>
<tbody>
<tr>
<td>Status quo</td>
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<tr>
<td></td>
</tr>
<tr>
<td>PUC</td>
</tr>
</tbody>
</table>

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. 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.

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. Also, there are nine regional offices under the Environmental Services Administration department.

Figure 15. Organizational chart of Malaysia ST


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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. Moreover, the total number is projected to increase over the next few years and will reach 350 by 2020. 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 resulting 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**

![Graph showing 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. 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**

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There are around 60 employees in the AUC in the past three years (2015 – 2017), but the numbers of employees in the years before the implementation of Conventional PBR are not publicly available.

**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

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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](image)


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).

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

<table>
<thead>
<tr>
<th>Employment category</th>
<th>Approximate # of Staff</th>
<th>Major background/expertise of Staff</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chair</td>
<td>1</td>
<td>management</td>
</tr>
<tr>
<td>Chief Executive</td>
<td>1</td>
<td>management, operations</td>
</tr>
<tr>
<td>Executive Directors &amp; General Managers</td>
<td>6</td>
<td>management, executive assistance, daily operations</td>
</tr>
<tr>
<td>Chief Financial Officer &amp; Director, HR</td>
<td>2</td>
<td>human resource management, operations</td>
</tr>
<tr>
<td>Directors</td>
<td>16</td>
<td>management, daily operations</td>
</tr>
<tr>
<td>Managers</td>
<td>4</td>
<td>management, daily operations</td>
</tr>
<tr>
<td>Analysts</td>
<td>77</td>
<td>project support, technical assistance, research, analysis</td>
</tr>
<tr>
<td>Graduate Analysts</td>
<td>3</td>
<td>project support, technical assistance, research, analysis</td>
</tr>
<tr>
<td>General Counsel</td>
<td>1</td>
<td>policy advisory</td>
</tr>
<tr>
<td>Director, Legal &amp; Special Counsel</td>
<td>2</td>
<td>legal advisory, policy advisory, planning</td>
</tr>
<tr>
<td>Legal Officers</td>
<td>3</td>
<td>legal assistance, policy advisory</td>
</tr>
<tr>
<td>Support Officers</td>
<td>23</td>
<td>technical assistance, administration, information technology</td>
</tr>
<tr>
<td>Supernumeraries</td>
<td>12</td>
<td>N/A</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>151</strong></td>
<td>N/A</td>
</tr>
</tbody>
</table>

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.


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.


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


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. 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. The number of staff members in EWON are not publicly available.

Figure 21. Description of divisions and required expertise of staff members in EWON

<table>
<thead>
<tr>
<th>Divisions</th>
<th>Description of Divisions</th>
<th>Major background/expertise of Staff</th>
</tr>
</thead>
<tbody>
<tr>
<td>People</td>
<td>responsible for maximizing staff engagement and contribution, and develops HR strategy</td>
<td>human resources, development</td>
</tr>
<tr>
<td>Finance &amp; Corporate Services</td>
<td>manages financial reporting, ICT infrastructure and service delivery, and general administration and facility management</td>
<td>data analysis, information technology, finance, coordination</td>
</tr>
<tr>
<td>Investigations</td>
<td>handles customer complaints against providers, including receiving, assessing, investigating, and reviewing complaints</td>
<td>research, case review, assessment, resolution</td>
</tr>
<tr>
<td>Governance, Awareness &amp; Policy</td>
<td>oversees governance, quality, member relations, communication, community outreach, and policy functions</td>
<td>policy, research, quality assurance, community engagement, communications</td>
</tr>
</tbody>
</table>

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 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


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).

| Number of staff : 100,000 customers |

<table>
<thead>
<tr>
<th></th>
<th>Status quo</th>
<th>The Hybrid Model</th>
</tr>
</thead>
<tbody>
<tr>
<td>PUC</td>
<td>12.8</td>
<td>18.9</td>
</tr>
</tbody>
</table>

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.

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. 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. 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. 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.” 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. 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. 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**

<table>
<thead>
<tr>
<th>Divisions</th>
<th>Description of divisions</th>
<th>Major background/expertise of Staff</th>
</tr>
</thead>
<tbody>
<tr>
<td>Executive Office</td>
<td>senior management of the organization and relevant support</td>
<td>management, development, administration</td>
</tr>
<tr>
<td>Policy and Legal Affairs</td>
<td>special counsel and senior policy advisor regarding strategic planning; make recommendations to the Commission on policy, regulatory, and legal matters</td>
<td>expertise in policy, regulatory, and legal matters</td>
</tr>
<tr>
<td>Secretary to the Commission</td>
<td>maintaining the records of the proceedings with the DPS; coordination of the components of proceedings; etc.</td>
<td>administration, documentation, clerical services, knowledge of ethical responsibilities as employees, etc.</td>
</tr>
<tr>
<td>Public Affairs</td>
<td>an advocate for the utility regulatory policies, programs, and initiatives; an integrated internal and external communications program</td>
<td>communications, public relations</td>
</tr>
<tr>
<td>Long Island Office</td>
<td>examining the core utility operations of PSEG Long Island, and advising the Long Island Power Authority</td>
<td>operations of utilities</td>
</tr>
<tr>
<td>Office of Administration</td>
<td>consisting of three sections including the Human Resources Management section, the Administrative Management section, and the Finance and Budget section</td>
<td>recruitment, human resources, administrative management, fiscal, and budgeting</td>
</tr>
</tbody>
</table>


87 Ibid.


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. 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.

---

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


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.” However, data of staffing members of this subdivision is not publicly available.


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.
Appendix B: Works Cited


Hawaii PUC. Response to LEI’s data requests via email on November 21, 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 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.

<table>
<thead>
<tr>
<th></th>
<th>$ thousands</th>
<th>HECO</th>
<th>HELCO</th>
<th>MECO</th>
<th>KIUC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost</td>
<td></td>
<td>4,362,431</td>
<td>1,273,720</td>
<td>1,128,445</td>
<td>515,881</td>
</tr>
<tr>
<td>Accumulated Depreciation</td>
<td></td>
<td>(1,750,994)</td>
<td>(613,768)</td>
<td>(521,055)</td>
<td>(271,185)</td>
</tr>
<tr>
<td>Net Book Value</td>
<td></td>
<td>2,611,437</td>
<td>659,952</td>
<td>607,390</td>
<td>244,696</td>
</tr>
</tbody>
</table>

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 criteria³ listed in Figure 2.

---

1 Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).


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.  

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**

![Book value formula diagram]

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.

---

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:

---


"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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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.


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, 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.

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.

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11 PUC Dockets 2010-0053 (HECO); 2009-0321 (HELCO); 2009-0286 (MECO); 2011-0128 (KIUC).


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.

<table>
<thead>
<tr>
<th>$ thousands</th>
<th>HECO</th>
<th>HELCO</th>
<th>MECO</th>
<th>KIUC</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Cost</strong></td>
<td>4,362,431</td>
<td>1,273,720</td>
<td>1,128,445</td>
<td>515,881</td>
</tr>
<tr>
<td><strong>Accumulated Depreciation</strong></td>
<td>(1,750,994)</td>
<td>(613,768)</td>
<td>(521,055)</td>
<td>(271,185)</td>
</tr>
<tr>
<td><strong>Net Book Value</strong></td>
<td>2,611,437</td>
<td>659,952</td>
<td>607,390</td>
<td>244,696</td>
</tr>
</tbody>
</table>

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.

<table>
<thead>
<tr>
<th>$ thousands</th>
<th>Production</th>
<th>T &amp; D</th>
<th>General</th>
<th>Land</th>
<th>Tenant Allowance</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Cost</strong></td>
<td>992,293</td>
<td>2,954,735</td>
<td>357,374</td>
<td>43,971</td>
<td>14,058</td>
<td>4,362,431</td>
</tr>
<tr>
<td><strong>Accumulated Depreciation</strong></td>
<td>(357,696)</td>
<td>(1,241,203)</td>
<td>(143,973)</td>
<td>0</td>
<td>(8,122)</td>
<td>(1,750,994)</td>
</tr>
<tr>
<td><strong>Net Book Value</strong></td>
<td>634,597</td>
<td>1,713,532</td>
<td>213,401</td>
<td>43,971</td>
<td>5,936</td>
<td>2,611,437</td>
</tr>
<tr>
<td><strong>Percent depreciated</strong></td>
<td>36%</td>
<td>42%</td>
<td>40%</td>
<td>0%</td>
<td>58%</td>
<td>40%</td>
</tr>
</tbody>
</table>

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**

<table>
<thead>
<tr>
<th>PRODUCTION PLANT</th>
<th>Original Cost ($ thousands)</th>
<th>Avg Service Life (years)</th>
<th>Depreciation Rate</th>
<th>Amortization Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Steam Production Plant</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>311 Structures and Improvements</td>
<td>96,421</td>
<td>54</td>
<td>1.60%</td>
<td>-</td>
</tr>
<tr>
<td>312 Boiler Plant Equipment</td>
<td>392,071</td>
<td>47</td>
<td>2.03%</td>
<td>-</td>
</tr>
<tr>
<td>313 Engines and Engine-Drive Generators</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>314 Turbogenerator Units</td>
<td>189,998</td>
<td>51</td>
<td>1.54%</td>
<td>-</td>
</tr>
<tr>
<td>315 Accessory Electric Equipment</td>
<td>80,971</td>
<td>44</td>
<td>2.43%</td>
<td>-</td>
</tr>
<tr>
<td>316 Misc. Power Plant Equipment</td>
<td>23,984</td>
<td>20</td>
<td>5.00%</td>
<td>-</td>
</tr>
<tr>
<td>317 Asset Retirement Costs for Steam Production</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Steam Production Plant</strong></td>
<td>783,445</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Other Production Plant</strong>*</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>341 Structures and Improvements</td>
<td>38,507</td>
<td>53</td>
<td>0.77%</td>
<td>-</td>
</tr>
<tr>
<td>342 Fuel Holders, Products, and Accessories</td>
<td>16,598</td>
<td>39</td>
<td>2.58%</td>
<td>-</td>
</tr>
<tr>
<td>343 Prime Movers</td>
<td>68,247</td>
<td>48</td>
<td>3.26%</td>
<td>-</td>
</tr>
<tr>
<td>344 Generators</td>
<td>32,457</td>
<td>51</td>
<td>1.01%</td>
<td>-</td>
</tr>
<tr>
<td>345 Accessory Electric Equipment</td>
<td>34,059</td>
<td>46</td>
<td>2.51%</td>
<td>-</td>
</tr>
<tr>
<td>346 Misc. Power Plant Equipment</td>
<td>18,979</td>
<td>20</td>
<td>5.00%</td>
<td>-</td>
</tr>
<tr>
<td>347 Asset Retirement Costs for Other Production</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Other Production Plant</strong></td>
<td>208,847</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total Production Plant</strong></td>
<td>992,293</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

* Other production plants include all plants other than steam, nuclear, and hydraulic production plants

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.
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

<table>
<thead>
<tr>
<th>DISTRIBUTION PLANT</th>
<th>Original Cost ($ thousands)</th>
<th>Avg Service Life (years)</th>
<th>Depreciation Rate</th>
<th>Amortization Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>361 Structures and Improvements</td>
<td>22,967</td>
<td>65</td>
<td>1.08%</td>
<td>-</td>
</tr>
<tr>
<td>362 Station Equipment</td>
<td>256,831</td>
<td>55</td>
<td>2.02%</td>
<td>-</td>
</tr>
<tr>
<td>363 Storage Battery Equipment</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>364 Poles, Towers, and Fixtures</td>
<td>217,333</td>
<td>50</td>
<td>3.34%</td>
<td>-</td>
</tr>
<tr>
<td>365 Overhead Conductors and Devices</td>
<td>123,273</td>
<td>50</td>
<td>4.19%</td>
<td>-</td>
</tr>
<tr>
<td>366 Underground Conduit</td>
<td>316,345</td>
<td>60</td>
<td>2.19%</td>
<td>-</td>
</tr>
<tr>
<td>367 Underground Conductors and Devices</td>
<td>452,228</td>
<td>51</td>
<td>4.98%</td>
<td>-</td>
</tr>
<tr>
<td>368 Line Transformers</td>
<td>238,232</td>
<td>30</td>
<td>5.20%</td>
<td>-</td>
</tr>
<tr>
<td>369.1 Services - Overhead</td>
<td>270,782</td>
<td>55</td>
<td>5.25%</td>
<td>-</td>
</tr>
<tr>
<td>369.2 Services - Underground</td>
<td>38,796</td>
<td>60</td>
<td>4.07%</td>
<td>-</td>
</tr>
<tr>
<td>370 Meters</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Total Distribution Plant</td>
<td>1,936,778</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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.
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.

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

<table>
<thead>
<tr>
<th>PRODUCTION PLANT</th>
<th>Original Cost ($ thousands)</th>
<th>Avg Service Life (years)</th>
<th>Depreciation Rate</th>
<th>Amortization Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Steam Production Plant</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>311 Structures and Improvements</td>
<td>18,378</td>
<td>40</td>
<td>2.90%</td>
<td>-</td>
</tr>
<tr>
<td>312 Boiler Plant Equipment</td>
<td>68,074</td>
<td>34</td>
<td>3.08%</td>
<td>-</td>
</tr>
<tr>
<td>313 Engines and Engine-Drive Generators</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>314 Turbogenerator Units</td>
<td>47,820</td>
<td>35</td>
<td>2.54%</td>
<td>-</td>
</tr>
<tr>
<td>315 Accessory Electric Equipment</td>
<td>8,940</td>
<td>32</td>
<td>3.35%</td>
<td>-</td>
</tr>
<tr>
<td>316 Misc. Power Plant Equipment</td>
<td>2,001</td>
<td>20</td>
<td>-</td>
<td>5.00%</td>
</tr>
<tr>
<td>317 Asset Retirement Costs for Steam Production</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Steam Production Plant</strong></td>
<td>145,214</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Hydraulic Production Plant</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>331 Structures and Improvements</td>
<td>97</td>
<td>65</td>
<td>0.94%</td>
<td>-</td>
</tr>
<tr>
<td>332 Resevoirs, Dams, and Waterways</td>
<td>6,189</td>
<td>50</td>
<td>2.03%</td>
<td>-</td>
</tr>
<tr>
<td>333 Water Wheels, Turbines, and Generators</td>
<td>2,093</td>
<td>47</td>
<td>2.13%</td>
<td>-</td>
</tr>
<tr>
<td>334 Accessory Electric Equipment</td>
<td>743</td>
<td>88</td>
<td>0.82%</td>
<td>-</td>
</tr>
<tr>
<td>335 Misc. Power Plant Equipment</td>
<td>137</td>
<td>20</td>
<td>-</td>
<td>5.00%</td>
</tr>
<tr>
<td>336 Roads, Railroads, and Bridges</td>
<td>120</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>337 Asset Retirement Costs for Hydraulic Production</td>
<td>0</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Hydraulic Production Plant</strong></td>
<td>9,379</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Other Production Plant</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>341 Structures and Improvements</td>
<td>24,480</td>
<td>38</td>
<td>2.64%</td>
<td>-</td>
</tr>
<tr>
<td>342 Fuel Holders, Products, and Accessories</td>
<td>12,541</td>
<td>39</td>
<td>2.64%</td>
<td>-</td>
</tr>
<tr>
<td>343 Prime Movers</td>
<td>71,192</td>
<td>39</td>
<td>2.64%</td>
<td>-</td>
</tr>
<tr>
<td>344 Generators</td>
<td>53,848</td>
<td>41</td>
<td>2.64%</td>
<td>-</td>
</tr>
<tr>
<td>345 Accessory Electric Equipment</td>
<td>7,742</td>
<td>44</td>
<td>2.64%</td>
<td>-</td>
</tr>
<tr>
<td>346 Misc. Power Plant Equipment</td>
<td>3,083</td>
<td>20</td>
<td>-</td>
<td>5.00%</td>
</tr>
<tr>
<td>347 Asset Retirement Costs for Other Production</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Other Production Plant</strong></td>
<td>172,886</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total Production Plant</strong></td>
<td>327,478</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*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.
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.

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.
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.

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

<table>
<thead>
<tr>
<th>PRODUCTION PLANT</th>
<th>Original Cost ($ thousands)</th>
<th>Avg Service Life (years)</th>
<th>Depreciation Rate</th>
<th>Amortization Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Steam Production Plant</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>311 Structures and Improvements</td>
<td>6,985</td>
<td>28</td>
<td>2.89%</td>
<td>-</td>
</tr>
<tr>
<td>312 Boiler Plant Equipment</td>
<td>52,156</td>
<td>27</td>
<td>3.75%</td>
<td>-</td>
</tr>
<tr>
<td>313 Engines and Engine-Drive Generators</td>
<td>-</td>
<td>-</td>
<td>0.00%</td>
<td>-</td>
</tr>
<tr>
<td>314 Turbogenerator Units</td>
<td>50,578</td>
<td>21</td>
<td>5.89%</td>
<td>-</td>
</tr>
<tr>
<td>315 Accessory Electric Equipment</td>
<td>9,165</td>
<td>27</td>
<td>4.19%</td>
<td>-</td>
</tr>
<tr>
<td>316 Misc. Power Plant Equipment</td>
<td>3,302</td>
<td>20</td>
<td>-</td>
<td>5.00%</td>
</tr>
<tr>
<td>317 Asset Retirement Costs for Steam Production</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Total Steam Production Plant</td>
<td>122,186</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Other Production Plant*</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>341 Structures and Improvements</td>
<td>42,847</td>
<td>29 to 45**</td>
<td>1.17% to 4.54%**</td>
<td>-</td>
</tr>
<tr>
<td>342 Fuel Holders, Products, and Accessories</td>
<td>8,564</td>
<td>28 to 45**</td>
<td>0.97% to 4.52%**</td>
<td>-</td>
</tr>
<tr>
<td>343 Prime Movers</td>
<td>50,738</td>
<td>31 to 52**</td>
<td>0.80% to 2.60%**</td>
<td>-</td>
</tr>
<tr>
<td>344 Generators</td>
<td>131,519</td>
<td>29 to 45**</td>
<td>1.54% to 3.54%**</td>
<td>-</td>
</tr>
<tr>
<td>345 Accessory Electric Equipment</td>
<td>38,497</td>
<td>29 to 46**</td>
<td>1.57% to 2.68%**</td>
<td>-</td>
</tr>
<tr>
<td>346 Misc. Power Plant Equipment</td>
<td>17,475</td>
<td>5</td>
<td>-</td>
<td>5.00%</td>
</tr>
<tr>
<td>347 Asset Retirement Costs for Other Production</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Total Other Production Plant</td>
<td>289,640</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Total Production Plant</td>
<td>411,826</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

* 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.
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 18. MECO transmission assets by category

<table>
<thead>
<tr>
<th>TRANSMISSION PLANT</th>
<th>Original Cost ($ thousands)</th>
<th>Avg Service Life (years)</th>
<th>Depreciation Rate</th>
<th>Amortization Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>352 Structures and Improvements</td>
<td>7,415</td>
<td>50</td>
<td>2.02%</td>
<td>-</td>
</tr>
<tr>
<td>353 Station Equipment</td>
<td>56,067</td>
<td>59</td>
<td>1.58% to 2.32%**</td>
<td>-</td>
</tr>
<tr>
<td>354 Towers and Fixtures</td>
<td>40</td>
<td>50</td>
<td>2.33%</td>
<td>-</td>
</tr>
<tr>
<td>355 Poles and Fixtures</td>
<td>33,766</td>
<td>70</td>
<td>0.77% to 1.57%**</td>
<td>-</td>
</tr>
<tr>
<td>356 Overhead Conductors and Devices</td>
<td>27,687</td>
<td>65</td>
<td>0.97% to 1.75%**</td>
<td>-</td>
</tr>
<tr>
<td>357 Underground Conduit</td>
<td>730</td>
<td>60</td>
<td>1.59%</td>
<td>-</td>
</tr>
<tr>
<td>358 Underground Conductors and Devices</td>
<td>1,221</td>
<td>50</td>
<td>1.98%</td>
<td>-</td>
</tr>
<tr>
<td>359 Roads and Trails</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Transmission Plant</strong></td>
<td><strong>126,925</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

** varies by island

Source: MECO 2016 annual report; HECO Companies response to LEI data request

### Figure 19. MECO distribution assets by category

<table>
<thead>
<tr>
<th>DISTRIBUTION PLANT</th>
<th>Original Cost ($ thousands)</th>
<th>Avg Service Life (years)</th>
<th>Depreciation Rate</th>
<th>Amortization Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>361 Structures and Improvements</td>
<td>1,788</td>
<td>50</td>
<td>2.02% to 2.03%**</td>
<td>-</td>
</tr>
<tr>
<td>362 Station Equipment</td>
<td>56,335</td>
<td>55</td>
<td>0.66% to 1.20%**</td>
<td>-</td>
</tr>
<tr>
<td>363 Storage Battery Equipment</td>
<td>5,559</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>364 Poles, Towers, and Fixtures</td>
<td>48,598</td>
<td>56</td>
<td>1.70% to 2.24%**</td>
<td>-</td>
</tr>
<tr>
<td>365 Overhead Conductors and Devices</td>
<td>68,317</td>
<td>58</td>
<td>1.65% to 1.77%**</td>
<td>-</td>
</tr>
<tr>
<td>366 Underground Conduit</td>
<td>64,995</td>
<td>80</td>
<td>2.03% to 2.27%**</td>
<td>-</td>
</tr>
<tr>
<td>367 Underground Conductors and Devices</td>
<td>84,606</td>
<td>55</td>
<td>1.17% to 1.74%**</td>
<td>-</td>
</tr>
<tr>
<td>368 Line Transformers</td>
<td>70,300</td>
<td>45</td>
<td>2.06% to 2.25%**</td>
<td>-</td>
</tr>
<tr>
<td>369.1 Services - Overhead</td>
<td>97,648</td>
<td>45</td>
<td>3.78% to 4.06%**</td>
<td>-</td>
</tr>
<tr>
<td>369.2 Services - Underground</td>
<td>97,648</td>
<td>45</td>
<td>2.32% to 2.61%**</td>
<td>-</td>
</tr>
<tr>
<td>370 Meters</td>
<td>14,873</td>
<td>43</td>
<td>1.21% to 1.95%**</td>
<td>-</td>
</tr>
<tr>
<td>373 Street Lighting and Signal Systems</td>
<td>14,440</td>
<td>45</td>
<td>1.52% to 1.87%**</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Distribution Plant</strong></td>
<td><strong>527,460</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

** 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.
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,\(^\text{15}\) as illustrated in Figure 21.

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**

<table>
<thead>
<tr>
<th>PRODUCTION PLANT</th>
<th>Original Cost ($)</th>
<th>Avg Service Life (years)</th>
<th>Depreciation Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Steam Production Plant</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>311 Structures and Improvements</td>
<td>5,639</td>
<td>51</td>
<td>2.59%</td>
</tr>
<tr>
<td>312 Boiler Plant Equipment</td>
<td>15,810</td>
<td>31</td>
<td>2.60%</td>
</tr>
<tr>
<td>313 Engines and Engine-Drive Generators</td>
<td>6</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>314 Turbogenerator Units</td>
<td>2,783</td>
<td>52</td>
<td>3.49%</td>
</tr>
<tr>
<td>315 Accessory Electric Equipment</td>
<td>777</td>
<td>54</td>
<td>2.52%</td>
</tr>
<tr>
<td>316 Misc. Power Plant Equipment</td>
<td>669</td>
<td>35</td>
<td>6.78%</td>
</tr>
<tr>
<td>317 Asset Retirement Costs for Steam Production</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Steam Production Plant</strong></td>
<td>25,684</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Hydraulic Production Plant</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>331 Structures and Improvements</td>
<td>738</td>
<td>35</td>
<td>3.76%</td>
</tr>
<tr>
<td>332 Reservoirs, Dams, and Waterways</td>
<td>2,031</td>
<td>35</td>
<td>3.48%</td>
</tr>
<tr>
<td>333 Water Wheels, Turbines, and Generators</td>
<td>666</td>
<td>26</td>
<td>4.24%</td>
</tr>
<tr>
<td>334 Accessory Electric Equipment</td>
<td>582</td>
<td></td>
<td></td>
</tr>
<tr>
<td>335 Misc. Power Plant Equipment</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>336 Roads, Railroads, and Bridges</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>337 Asset Retirement Costs for Hydraulic Production</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Hydraulic Production Plant</strong></td>
<td><em>4,017</em></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Other Production Plant</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>341 Structures and Improvements</td>
<td>18,664</td>
<td>40</td>
<td>3.34%</td>
</tr>
<tr>
<td>342 Fuel Holders, Products, and Accessories</td>
<td>4,927</td>
<td>39</td>
<td>3.42%</td>
</tr>
<tr>
<td>343 Prime Movers</td>
<td>66,985</td>
<td>34</td>
<td>3.15%</td>
</tr>
<tr>
<td>344 Generators</td>
<td>11,312</td>
<td>37</td>
<td>2.98%</td>
</tr>
<tr>
<td>345 Accessory Electric Equipment</td>
<td>9,321</td>
<td>37</td>
<td>1.58%</td>
</tr>
<tr>
<td>346 Misc. Power Plant Equipment</td>
<td>2,268</td>
<td>34</td>
<td>2.44%</td>
</tr>
<tr>
<td>347 Asset Retirement Costs for Other Production</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Other Production Plant</strong></td>
<td>113,476</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total Production Plant</strong></td>
<td>143,178</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>TRANSMISSION PLANT</th>
<th>Original Cost ($ thousands)</th>
<th>Avg Service Life (years)</th>
<th>Depreciation Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>352 Structures and Improvements</td>
<td>263</td>
<td>51</td>
<td>1.33%</td>
</tr>
<tr>
<td>353 Station Equipment</td>
<td>25,607</td>
<td>38</td>
<td>2.50%</td>
</tr>
<tr>
<td>354 Towers and Fixtures</td>
<td>58</td>
<td>50</td>
<td>1.86%</td>
</tr>
<tr>
<td>355 Poles and Fixtures</td>
<td>30,534</td>
<td>56</td>
<td>1.22%</td>
</tr>
<tr>
<td>356 Overhead Conductors and Devices</td>
<td>20,793</td>
<td>42</td>
<td>2.01%</td>
</tr>
<tr>
<td>357 Underground Conduit</td>
<td>9</td>
<td>60</td>
<td>1.48%</td>
</tr>
<tr>
<td>358 Underground Conductors and Devices</td>
<td>492</td>
<td>50</td>
<td>2.18%</td>
</tr>
<tr>
<td>359 Roads and Trails</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Transmission Plant</strong></td>
<td><strong>77,755</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>


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

<table>
<thead>
<tr>
<th>DISTRIBUTION PLANT</th>
<th>Original Cost ($ thousands)</th>
<th>Avg Service Life (years)</th>
<th>Depreciation Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>361 Structures and Improvements</td>
<td>3,622</td>
<td>50</td>
<td>2.09%</td>
</tr>
<tr>
<td>362 Station Equipment</td>
<td>19,892</td>
<td>33</td>
<td>3.13%</td>
</tr>
<tr>
<td>363 Storage Battery Equipment</td>
<td>7,628</td>
<td>20</td>
<td>4.98%</td>
</tr>
<tr>
<td>364 Poles, Towers, and Fixtures</td>
<td>36,685</td>
<td>55</td>
<td>1.59%</td>
</tr>
<tr>
<td>365 Overhead Conductors and Devices</td>
<td>38,998</td>
<td>36</td>
<td>3.18%</td>
</tr>
<tr>
<td>366 Underground Conduit</td>
<td>7,944</td>
<td>63</td>
<td>1.34%</td>
</tr>
<tr>
<td>367 Underground Conductors and Devices</td>
<td>25,047</td>
<td>41</td>
<td>1.98%</td>
</tr>
<tr>
<td>368 Line Transformers</td>
<td>25,691</td>
<td>29</td>
<td>4.50%</td>
</tr>
<tr>
<td>369 Services</td>
<td>6,744</td>
<td>53</td>
<td>1.35%</td>
</tr>
<tr>
<td>370 Meters</td>
<td>7,417</td>
<td>15</td>
<td>13.59%</td>
</tr>
<tr>
<td>371 Installations on Customer’s Premises</td>
<td>29</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>372 Leased Property</td>
<td>19</td>
<td>10</td>
<td>12.26%</td>
</tr>
<tr>
<td>373 Street Lighting and Signal Systems</td>
<td>3,482</td>
<td>25</td>
<td>2.45%</td>
</tr>
<tr>
<td><strong>Total Distribution Plant</strong></td>
<td><strong>183,197</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>


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.

<table>
<thead>
<tr>
<th>GENERAL PLANT</th>
<th>Original Cost ($ thousands)</th>
<th>Avg Service Life (years)</th>
<th>Depreciation Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>390 Structures and Improvements</td>
<td>11,619</td>
<td>42</td>
<td>1.91%</td>
</tr>
<tr>
<td>391 Office Furniture and Equipment</td>
<td>10,084</td>
<td>20</td>
<td>3.94%</td>
</tr>
<tr>
<td>392 Transportation Equipment</td>
<td>5,800</td>
<td>7</td>
<td>2.96%</td>
</tr>
<tr>
<td>393 Stores Equipment</td>
<td>172</td>
<td>21</td>
<td>3.81%</td>
</tr>
<tr>
<td>394 Tools, Shop and Garage Equipment</td>
<td>1,806</td>
<td>15</td>
<td>6.40%</td>
</tr>
<tr>
<td>395 Laboratory Equipment</td>
<td>823</td>
<td>15</td>
<td>4.75%</td>
</tr>
<tr>
<td>396 Power Operated Equipment</td>
<td>257</td>
<td>15</td>
<td>2.02%</td>
</tr>
<tr>
<td>397 Communication Equipment</td>
<td>4,319</td>
<td>16</td>
<td>5.23%</td>
</tr>
<tr>
<td>398 Miscellaneous Equipment</td>
<td>1,341</td>
<td>15</td>
<td>6.45%</td>
</tr>
<tr>
<td><strong>Total General Plant</strong></td>
<td><strong>36,220</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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.
Appendix B: List of works consulted


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
<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>PSIP</td>
<td>Power Supply Improvement Plan</td>
</tr>
<tr>
<td>PUA</td>
<td>Public Utility Act</td>
</tr>
<tr>
<td>PUC</td>
<td>Hawaii Public Utilities Commission</td>
</tr>
<tr>
<td>RAB</td>
<td>Regulatory Asset Base</td>
</tr>
<tr>
<td>REDG</td>
<td>Rural Economic Development Grant</td>
</tr>
<tr>
<td>RFP</td>
<td>Request for Proposals</td>
</tr>
<tr>
<td>RLF</td>
<td>Revolving Loan Fund</td>
</tr>
<tr>
<td>ROE</td>
<td>Return on Equity</td>
</tr>
<tr>
<td>RPS</td>
<td>Renewable Portfolio Standards</td>
</tr>
<tr>
<td>RUS</td>
<td>Rural Utilities Service</td>
</tr>
<tr>
<td>SB</td>
<td>Single Buyer</td>
</tr>
<tr>
<td>T&amp;D</td>
<td>Transmission and Distribution</td>
</tr>
<tr>
<td>TIER</td>
<td>Times Interest Earned Ratio</td>
</tr>
<tr>
<td>TNB</td>
<td>Tenaga Nasional Berhad</td>
</tr>
<tr>
<td>USDA</td>
<td>United States Department of Agriculture</td>
</tr>
<tr>
<td>WACC</td>
<td>Weighted Average Cost of Capital</td>
</tr>
</tbody>
</table>
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](source: LEI analysis.)

<table>
<thead>
<tr>
<th>Upfront costs</th>
<th>Coop</th>
<th>SB (within the utility)</th>
<th>SB (outside)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Setup</td>
<td>↑</td>
<td>↑</td>
<td>↑</td>
</tr>
<tr>
<td>Acquisition</td>
<td>↑</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Personnel and transition</td>
<td>↑</td>
<td>↑</td>
<td>↑</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Recurring</th>
<th>Coop</th>
<th>SB (within the utility)</th>
<th>SB (outside)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost of capital</td>
<td>↓</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Rate base</td>
<td>↓</td>
<td>↑</td>
<td>-</td>
</tr>
<tr>
<td>Power supply costs</td>
<td>-</td>
<td>↓</td>
<td>↓</td>
</tr>
<tr>
<td>Taxes</td>
<td>↓</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Non-labor operating costs</td>
<td>-</td>
<td>↑</td>
<td>↑</td>
</tr>
<tr>
<td>Labor operating costs</td>
<td>-</td>
<td>↑</td>
<td>↑</td>
</tr>
<tr>
<td>Regulatory compliance</td>
<td>-</td>
<td>-</td>
<td>↑</td>
</tr>
</tbody>
</table>

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**

![Diagram showing key criteria for evaluating utility ownership and regulatory 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 criteria3 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).


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)](image)

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 ("Ke"), and cost of debt ("Kd"), 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](image)

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

<table>
<thead>
<tr>
<th>To use the utility’s actual structure</th>
<th>To set a target range for capital structure</th>
<th>To set a fixed capital structure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Simplest option</td>
<td>Any structure within that range is allowed</td>
<td>The downside to requiring a particular structure is that it restricts management’s freedom to capitalize in an optimal manner</td>
</tr>
<tr>
<td>May create an incentive for the utility to take on more debt than appropriate, particularly if the allowed costs of equity and debt fluctuate over time</td>
<td>It is common in the US and also used in Ontario</td>
<td></td>
</tr>
</tbody>
</table>

### 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.

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. 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. 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.

---


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

<table>
<thead>
<tr>
<th>Options</th>
<th>Description</th>
<th>Examples</th>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Asset Pricing Model (CAPM)</td>
<td>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</td>
<td>Many US jurisdictions, Canada, the UK, Europe, Asia</td>
<td>Provides a theoretically justified cost of capital for equity</td>
<td>Backwards looking, with beta, the market risk premium, and the risk-free rate set using historical measures</td>
</tr>
<tr>
<td>Dividend growth model</td>
<td>• By using the current market price and a valuation model, such as the Dividend Discount model</td>
<td>Used by publicly traded companies. Usually not used by regulated entities.</td>
<td>Being entirely market-driven, the rate of return estimate is that demanded by the market</td>
<td>Highly volatile, completely dependent on the assumptions used by the estimator</td>
</tr>
</tbody>
</table>
| 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.

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. 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. Interest rates would be based on HECO’s current long-term credit ratings, at the Adjusted London Interbank Offered Rate ("LIBOR") (as defined in the agreement) plus

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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.\textsuperscript{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.\textsuperscript{12} In December 2016, HECO raised $40 million by issuing unsecured senior notes\textsuperscript{13} due December 1, 2046.\textsuperscript{14} The HECO Companies have $50 million and $96 million in long-term debt due in 2018 and 2020, respectively.\textsuperscript{15}

**Figure 8. HECO Companies – Capital structure as of December 31, 2016**

<table>
<thead>
<tr>
<th>Amount ($000s)</th>
<th>Common Stock</th>
<th>Preferred Stock</th>
<th>Long-Term Debt</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO</td>
<td>1,248,841</td>
<td>22,293</td>
<td>915,437</td>
<td>2,186,571</td>
</tr>
<tr>
<td>MECO</td>
<td>259,554</td>
<td>5,000</td>
<td>190,210</td>
<td>454,764</td>
</tr>
<tr>
<td>HELCO</td>
<td>291,291</td>
<td>7,000</td>
<td>213,703</td>
<td>511,994</td>
</tr>
<tr>
<td>HECO Companies Total</td>
<td>1,799,686</td>
<td>34,293</td>
<td>1,319,350</td>
<td>3,153,329</td>
</tr>
</tbody>
</table>

**Figure 9. HECO Companies – WACC**

<table>
<thead>
<tr>
<th>Rate</th>
<th>Short-term Debt</th>
<th>Long-term Debt</th>
<th>Hybrids</th>
<th>Preferred Stock</th>
<th>Common Stock</th>
<th>WACC</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO</td>
<td>1.75%</td>
<td>5.19%</td>
<td>7.19%</td>
<td>5.37%</td>
<td>10.60%</td>
<td>8.28%</td>
</tr>
<tr>
<td>MECO</td>
<td>2.00%</td>
<td>4.59%</td>
<td>7.16%</td>
<td>8.15%</td>
<td>10.60%</td>
<td>8.05%</td>
</tr>
<tr>
<td>HELCO</td>
<td>1.50%</td>
<td>5.41%</td>
<td>7.21%</td>
<td>8.18%</td>
<td>10.60%</td>
<td>8.44%</td>
</tr>
<tr>
<td>HECO Companies Total</td>
<td>1.81%</td>
<td>5.15%</td>
<td>7.19%</td>
<td>6.36%</td>
<td>10.60%</td>
<td>8.28%</td>
</tr>
</tbody>
</table>

**Source:**\textsuperscript{11, 12} HECO. \textit{Annual Report to Hawaii PUC} – 2016. page 123.31.

\textsuperscript{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.

\textsuperscript{14} Ibid.

\textsuperscript{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](image)

<table>
<thead>
<tr>
<th>Long-term Debt</th>
<th>Controlling Equity</th>
<th>Non-Controlling Equity</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Amount ($000s)</td>
<td>208,650</td>
<td>102,981</td>
<td>21,518</td>
</tr>
<tr>
<td>Weight</td>
<td>62.6%</td>
<td>30.9%</td>
<td>6.5%</td>
</tr>
</tbody>
</table>


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.


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.

\[ TIER = \frac{(\text{Interest Expense} + \text{Margins})}{(\text{Interest Expense})} \]

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.


Figure 11. KIUC - Patronage Capital Growth (utility only)

<table>
<thead>
<tr>
<th>$000s</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Patronage Capital &amp; Memberships</td>
<td>78,546</td>
<td>85,289</td>
<td>93,019</td>
<td>96,529</td>
<td>102,981</td>
</tr>
<tr>
<td>Total Long-Term Debt</td>
<td>177,646</td>
<td>177,469</td>
<td>175,434</td>
<td>172,126</td>
<td>193,362</td>
</tr>
<tr>
<td>Total Capital</td>
<td>256,192</td>
<td>262,758</td>
<td>268,453</td>
<td>268,654</td>
<td>296,343</td>
</tr>
</tbody>
</table>

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.\textsuperscript{20} In addition, the co-op also has a 1-year unsecured $25 million line-of-credit for working capital with CoBank.\textsuperscript{21}

\begin{table}[h]
\centering
\begin{tabular}{lcc}
\hline
 & 2016 & 2015 \\
\hline
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 \\
\hline
\end{tabular}
\caption{KIUC Long-term Debt (as of December 31, 2016)}
\end{table}

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

\textsuperscript{20} Ibid. Page 18.

\textsuperscript{21} Ibid.
KIUC) is required to be at zero interest. 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. 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.

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22 USDA Rural Development. *Rural Economic Development Loan and Grant Programs, RD Instruction 4280-A.*


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.
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.
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.


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.

<table>
<thead>
<tr>
<th>Public Service Tax</th>
<th>PUC Fees</th>
<th>Franchise Tax</th>
</tr>
</thead>
<tbody>
<tr>
<td>5.885%</td>
<td>0.500%</td>
<td>2.500%</td>
</tr>
</tbody>
</table>

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)

<table>
<thead>
<tr>
<th>Tax expenses with 35% vs. 21% federal tax rate</th>
<th>HECO</th>
<th>MECO</th>
<th>HELCO</th>
<th>KIUC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Revenue (in $000s)</td>
<td>1,472,002</td>
<td>308,588</td>
<td>310,863</td>
<td>143,499</td>
</tr>
<tr>
<td>O&amp;M Expense (in $000s)</td>
<td>(1,008,805)</td>
<td>(213,353)</td>
<td>(199,951)</td>
<td>(98,880)</td>
</tr>
<tr>
<td>Taxes other than Income Taxes (in $000s)</td>
<td>(141,465)</td>
<td>(29,227)</td>
<td>(28,984)</td>
<td>(12,060)</td>
</tr>
<tr>
<td>EBITDA</td>
<td>321,732</td>
<td>66,008</td>
<td>81,928</td>
<td>32,559</td>
</tr>
<tr>
<td>Depreciation Expense (in $000s)</td>
<td>(130,259)</td>
<td>(24,790)</td>
<td>(40,589)</td>
<td>(18,473)</td>
</tr>
<tr>
<td>EBIT (Operating Income) (in $000s)</td>
<td>191,473</td>
<td>41,218</td>
<td>41,339</td>
<td>14,087</td>
</tr>
<tr>
<td>Interest Expense (in $000s)</td>
<td>(43,844)</td>
<td>(9,184)</td>
<td>(11,340)</td>
<td>(7,658)</td>
</tr>
<tr>
<td>Income before tax (in $000s)</td>
<td>147,629</td>
<td>32,034</td>
<td>29,999</td>
<td>6,429</td>
</tr>
<tr>
<td>Federal Income Tax Rate (in %)</td>
<td>35%</td>
<td>35%</td>
<td>35%</td>
<td>0%</td>
</tr>
<tr>
<td>State Income Tax Rate (in %)</td>
<td>6.015%</td>
<td>6.015%</td>
<td>6.015%</td>
<td>6.015%</td>
</tr>
<tr>
<td>Effective Income Tax Rate (in %)</td>
<td>38.910%</td>
<td>38.910%</td>
<td>38.910%</td>
<td>6.015%</td>
</tr>
<tr>
<td>Total Income Tax Expense (in $000s)</td>
<td>57,442</td>
<td>12,464</td>
<td>11,673</td>
<td>387</td>
</tr>
<tr>
<td>Federal Income Tax Rate (in %)</td>
<td>21%</td>
<td>21%</td>
<td>21%</td>
<td>0%</td>
</tr>
<tr>
<td>State Income Tax Rate (in %)</td>
<td>6.015%</td>
<td>6.015%</td>
<td>6.015%</td>
<td>6.015%</td>
</tr>
<tr>
<td>Effective Income Tax Rate (in %)</td>
<td>25.752%</td>
<td>25.752%</td>
<td>25.752%</td>
<td>6.015%</td>
</tr>
<tr>
<td>Total Income Tax Expense (in $000s)</td>
<td>38,017</td>
<td>8,249</td>
<td>7,725</td>
<td>387</td>
</tr>
<tr>
<td>Impact of lower corporate taxes (in $000s)</td>
<td>19,425</td>
<td>4,215</td>
<td>3,947</td>
<td>0</td>
</tr>
</tbody>
</table>


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.

<table>
<thead>
<tr>
<th>Coop Formation Steps</th>
<th>Cost ($000s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Leadership and Stakeholder Discussion</td>
<td>&lt; 10</td>
</tr>
<tr>
<td>Formation of a Provisional Committee</td>
<td>&lt; 10</td>
</tr>
<tr>
<td>Survey the Local Population</td>
<td>1 - 40</td>
</tr>
<tr>
<td>Formation of a Steering Committee</td>
<td>&lt; 100</td>
</tr>
<tr>
<td>Legal Outreach</td>
<td>&gt; 250</td>
</tr>
<tr>
<td>Feasibility Studies and Financial Analysis</td>
<td>&gt; 10</td>
</tr>
<tr>
<td>Incorporation and By-Laws</td>
<td>&lt; 10</td>
</tr>
<tr>
<td>Membership Recruitment</td>
<td>&lt; 100</td>
</tr>
<tr>
<td>Founding Assembly Meeting and Election of the Board</td>
<td>&lt; 10</td>
</tr>
<tr>
<td>Regulatory Approval</td>
<td>2,000 - 2,500</td>
</tr>
<tr>
<td><strong>Total Coop Formation Costs</strong></td>
<td><strong>2,350 - 3,320</strong></td>
</tr>
</tbody>
</table>

*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

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31 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

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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**

\[ Revenue \text{ Requirement} = \text{Regulatory Asset Base ("RAB") } \times WACC + \text{Operating Expenses} \]

**Figure 22. Co-op Revenue Requirements**

\[ TIER = \frac{(\text{Interest Expense } + \text{ Margins})}{(\text{Interest Expense})} \]

\[ \text{Margins} = \text{Interest Expense} \times (TIER - 1) \]

\[ Revenue \text{ Requirement} = \text{Interest Expense} \times (TIER - 1) + \text{Operating Expenses} \]

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**

<table>
<thead>
<tr>
<th>$000s</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Long-Term Debt</td>
<td>177,646</td>
<td>177,469</td>
<td>175,434</td>
<td>172,126</td>
<td>193,362</td>
<td></td>
</tr>
<tr>
<td>Interest Expense - Long-Term Debt</td>
<td>8,335</td>
<td>7,738</td>
<td>7,362</td>
<td>6,770</td>
<td>6,916</td>
<td></td>
</tr>
<tr>
<td>Approx. Blended Interest Rate</td>
<td>4.36%</td>
<td>4.15%</td>
<td>3.86%</td>
<td>4.02%</td>
<td>4.10%</td>
<td></td>
</tr>
</tbody>
</table>

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

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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)**

<table>
<thead>
<tr>
<th>($)000s</th>
<th>100% Debt</th>
<th>Interest Expense</th>
<th>70% Debt</th>
<th>Interest Expense</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO</td>
<td>3,249,000</td>
<td>133,060</td>
<td>2,274,300</td>
<td>93,142</td>
</tr>
<tr>
<td>MECO</td>
<td>761,000</td>
<td>31,166</td>
<td>532,700</td>
<td>21,816</td>
</tr>
<tr>
<td>HELCO</td>
<td>675,000</td>
<td>27,644</td>
<td>472,500</td>
<td>19,351</td>
</tr>
<tr>
<td>Total</td>
<td>4,685,000</td>
<td>191,870</td>
<td>3,279,500</td>
<td>134,309</td>
</tr>
</tbody>
</table>

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**

<table>
<thead>
<tr>
<th>($)000s</th>
<th>Net Plant</th>
<th>WACC</th>
<th>Capital Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO</td>
<td>2,557,890</td>
<td>8.28%</td>
<td>211,760</td>
</tr>
<tr>
<td>MECO</td>
<td>631,367</td>
<td>8.05%</td>
<td>50,856</td>
</tr>
<tr>
<td>HELCO</td>
<td>662,224</td>
<td>8.44%</td>
<td>55,918</td>
</tr>
<tr>
<td>Total</td>
<td>3,851,481</td>
<td></td>
<td>318,534</td>
</tr>
</tbody>
</table>

**Coop - 100% Debt**

<table>
<thead>
<tr>
<th>($)000s</th>
<th>Interest Expense</th>
<th>TIER - 1*</th>
<th>Margins</th>
<th>Decrease vs IOU</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO</td>
<td>133,060</td>
<td>1.50</td>
<td>199,590</td>
<td>12,170</td>
</tr>
<tr>
<td>MECO</td>
<td>31,166</td>
<td>1.50</td>
<td>46,749</td>
<td>4,107</td>
</tr>
<tr>
<td>HELCO</td>
<td>27,644</td>
<td>1.50</td>
<td>41,466</td>
<td>14,452</td>
</tr>
<tr>
<td>Total</td>
<td>191,870</td>
<td></td>
<td>287,805</td>
<td>30,729</td>
</tr>
</tbody>
</table>

**Coop - 70% Debt**

<table>
<thead>
<tr>
<th>($)000s</th>
<th>Interest Expense</th>
<th>TIER - 1*</th>
<th>Margins</th>
<th>Decrease vs IOU</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO</td>
<td>93,142</td>
<td>1.50</td>
<td>139,713</td>
<td>72,047</td>
</tr>
<tr>
<td>MECO</td>
<td>21,816</td>
<td>1.50</td>
<td>32,274</td>
<td>18,132</td>
</tr>
<tr>
<td>HELCO</td>
<td>19,351</td>
<td>1.50</td>
<td>29,026</td>
<td>26,891</td>
</tr>
<tr>
<td>Total</td>
<td>134,309</td>
<td></td>
<td>201,464</td>
<td>67,155</td>
</tr>
</tbody>
</table>

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**

<table>
<thead>
<tr>
<th>($000s)</th>
<th>IOU</th>
<th>Co-op</th>
<th>Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td>35% Federal Tax Rate</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HECO</td>
<td>57,442</td>
<td>8,880</td>
<td>48,562</td>
</tr>
<tr>
<td>MECO</td>
<td>12,464</td>
<td>1,927</td>
<td>10,538</td>
</tr>
<tr>
<td>HELCO</td>
<td>11,673</td>
<td>1,804</td>
<td>9,868</td>
</tr>
<tr>
<td><strong>HECO Companies Total</strong></td>
<td><strong>81,579</strong></td>
<td><strong>12,611</strong></td>
<td><strong>68,968</strong></td>
</tr>
<tr>
<td>21% Federal Tax Rate</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HECO</td>
<td>38,017</td>
<td>8,880</td>
<td>29,137</td>
</tr>
<tr>
<td>MECO</td>
<td>8,249</td>
<td>1,927</td>
<td>6,323</td>
</tr>
<tr>
<td>HELCO</td>
<td>7,725</td>
<td>1,804</td>
<td>5,921</td>
</tr>
<tr>
<td><strong>HECO Companies Total</strong></td>
<td><strong>53,992</strong></td>
<td><strong>12,611</strong></td>
<td><strong>41,381</strong></td>
</tr>
</tbody>
</table>

*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. KIUC has considered seeking eventual exemption from regulation by the PUC. 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**

<table>
<thead>
<tr>
<th>($000s)</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>5-year average</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO</td>
<td>398</td>
<td>476</td>
<td>509</td>
<td>580</td>
<td>290</td>
<td>451</td>
</tr>
<tr>
<td>MECO</td>
<td>1,149</td>
<td>364</td>
<td>247</td>
<td>249</td>
<td>0</td>
<td>402</td>
</tr>
<tr>
<td>HELCO</td>
<td>783</td>
<td>253</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>207</td>
</tr>
<tr>
<td><strong>HECO Total</strong></td>
<td><strong>2,330</strong></td>
<td><strong>1,093</strong></td>
<td><strong>756</strong></td>
<td><strong>829</strong></td>
<td><strong>290</strong></td>
<td><strong>1,060</strong></td>
</tr>
<tr>
<td>KIUC</td>
<td>1,149</td>
<td>1,657</td>
<td>1,368</td>
<td>1,239</td>
<td>1,312</td>
<td>1,345</td>
</tr>
</tbody>
</table>

*Source: SNL; KIUC Annual Report to the PUC (2012-2016).*

---


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.

<table>
<thead>
<tr>
<th>Training and travel expense</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>5-year average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Training and travel expense</td>
<td>77.9</td>
<td>84.7</td>
<td>93.5</td>
<td>65.9</td>
<td>69.9</td>
<td>78.4</td>
</tr>
</tbody>
</table>

**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.

<table>
<thead>
<tr>
<th>($000s)</th>
<th>HECO</th>
<th>MECO</th>
<th>HELCO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost of capital</td>
<td>(12,170)</td>
<td>(4,107)</td>
<td>(14,452)</td>
</tr>
<tr>
<td>Taxes</td>
<td>(48,563)</td>
<td>(10,538)</td>
<td>(9,868)</td>
</tr>
<tr>
<td>Board Training</td>
<td>78</td>
<td>78</td>
<td>78</td>
</tr>
<tr>
<td>Net Impact</td>
<td>(60,655)</td>
<td>(14,566)</td>
<td>(24,241)</td>
</tr>
</tbody>
</table>

**Source:** LEI analysis.
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.

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.


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

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. Prior 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.


### Figure 30. Ontario Power Authority – SB Capex

<table>
<thead>
<tr>
<th>Cost (2005 CAD)</th>
<th>Asset Life (years)</th>
<th>Cost ($000s, 2016 USD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Furniture and equipment</td>
<td>1,174,275</td>
<td>10</td>
</tr>
<tr>
<td>Leasehold improvements</td>
<td>1,458,998</td>
<td>Length of lease</td>
</tr>
<tr>
<td>Computer hardware and software</td>
<td>693,839</td>
<td>2.5</td>
</tr>
<tr>
<td>Audio visual equipment</td>
<td>135,843</td>
<td>10</td>
</tr>
<tr>
<td>Telephone system</td>
<td>49,217</td>
<td>5</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>3,512,172</strong></td>
<td></td>
</tr>
</tbody>
</table>

Note: FX conversion to 2005 USD (1 USD = 1.02 CAD); adjusted for inflation at 2%.


### Figure 31. Forecasted SB Capex for the first year of operations - HECO Companies

<table>
<thead>
<tr>
<th>($000s)</th>
<th>HECO</th>
<th>MECO</th>
<th>HELCO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Capex</td>
<td>3,140</td>
<td>514</td>
<td>913</td>
</tr>
</tbody>
</table>

*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.

<table>
<thead>
<tr>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Figure 32. HECO Companies’ System Planning – Current Staffing and Expenditure</strong></td>
</tr>
<tr>
<td>2016 data (actual or budgeted)</td>
</tr>
<tr>
<td># of staff</td>
</tr>
<tr>
<td>Labor expense ($000s)</td>
</tr>
<tr>
<td>Non-Labor expense ($000s)</td>
</tr>
<tr>
<td>Total annual expense ($000s)</td>
</tr>
</tbody>
</table>

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


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, 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.

<table>
<thead>
<tr>
<th>Source: LEI analysis.</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Figure 33. SB Office Estimated Rent Expense by IOU</th>
</tr>
</thead>
<tbody>
<tr>
<td># of staff</td>
</tr>
<tr>
<td>Space per employee (sq ft)</td>
</tr>
<tr>
<td>Rent base ($/sq ft per month)</td>
</tr>
<tr>
<td>Annual Rental Expense ($000s)</td>
</tr>
<tr>
<td>Annual Rental Expense ($000s)</td>
</tr>
</tbody>
</table>

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.

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According to the National Council of Nonprofits, an independent audit for a non-profit can cost from $10,000 to $20,000.\textsuperscript{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.\textsuperscript{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.\textsuperscript{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.

\textsuperscript{40} National Council of NonProfits. Nonprofit Audit Guide. Web. \textless https://www.councilofnonprofits.org/nonprofit-audit-guide/what-is-independent-audit\textgreater


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).

<table>
<thead>
<tr>
<th>Author(s)</th>
<th>Title</th>
<th>Study Period</th>
<th>Efficiency Gain</th>
</tr>
</thead>
<tbody>
<tr>
<td>K. Akkemik &amp; F. Oguz (2010)</td>
<td>Regulation, efficiency and equilibrium: A general equilibrium analysis of liberalization in the Turkish electricity.</td>
<td></td>
<td>14%</td>
</tr>
</tbody>
</table>

Figure 34. 2016 Purchased Power Costs and Potential Savings

<table>
<thead>
<tr>
<th>($000s)</th>
<th>Actual 2016</th>
<th>Savings (w/ 3% reduction)</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO</td>
<td>431,009</td>
<td>12,930</td>
</tr>
<tr>
<td>MECO</td>
<td>50,713</td>
<td>1,521</td>
</tr>
<tr>
<td>HELCO</td>
<td>81,018</td>
<td>2,431</td>
</tr>
<tr>
<td>HECO Total</td>
<td>562,740</td>
<td>16,882</td>
</tr>
</tbody>
</table>

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)](source: LEI analysis.)

<table>
<thead>
<tr>
<th>($)000s</th>
<th>HECO</th>
<th>MECO</th>
<th>HELCO</th>
<th>Combined</th>
</tr>
</thead>
<tbody>
<tr>
<td>SB Expenses</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>O&amp;M</td>
<td>9,738</td>
<td>4,929</td>
<td>5,599</td>
<td>9,738</td>
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<tr>
<td>Office Rent</td>
<td>279</td>
<td>46</td>
<td>81</td>
<td>279</td>
</tr>
<tr>
<td>Audit</td>
<td>15</td>
<td>15</td>
<td>15</td>
<td>15</td>
</tr>
<tr>
<td>IOU Cost Savings</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>O&amp;M</td>
<td>4,869</td>
<td>2,465</td>
<td>2,800</td>
<td>10,133</td>
</tr>
<tr>
<td>Purchased Power</td>
<td>12,930</td>
<td>1,521</td>
<td>2,431</td>
<td>16,882</td>
</tr>
<tr>
<td>Net Impact</td>
<td>(7,767)</td>
<td>1,004</td>
<td>465</td>
<td>(16,983)</td>
</tr>
</tbody>
</table>

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](source: HECO-1101, DOCKET NO. 2016-0328; MECO-702, DOCKET NO. 2017-0150; and HELCO-602, DOCKET NO. 2015-0170.)

<table>
<thead>
<tr>
<th>2016/2017 budgeted ($000s)</th>
<th>HECO</th>
<th>MECO</th>
<th>HELCO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Administrative expense</td>
<td>1,021</td>
<td>220</td>
<td>126</td>
</tr>
</tbody>
</table>
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.

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

<table>
<thead>
<tr>
<th>($000s)</th>
<th>HECO</th>
<th>MECO</th>
<th>HELCO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Capex</td>
<td>3,140</td>
<td>514</td>
<td>913</td>
</tr>
<tr>
<td>WACC</td>
<td>8.28%</td>
<td>8.05%</td>
<td>8.44%</td>
</tr>
<tr>
<td>Additional Earnings</td>
<td>260</td>
<td>41</td>
<td>77</td>
</tr>
</tbody>
</table>

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 $0.5 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

<table>
<thead>
<tr>
<th>($000s)</th>
<th>HECO</th>
<th>MECO</th>
<th>HELCO</th>
</tr>
</thead>
<tbody>
<tr>
<td>SB Expenses</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>O&amp;M</td>
<td>8,717</td>
<td>4,709</td>
<td>5,473</td>
</tr>
<tr>
<td>Office Rent</td>
<td>279</td>
<td>46</td>
<td>81</td>
</tr>
<tr>
<td>Incremental IOU earnings</td>
<td>260</td>
<td>41</td>
<td>77</td>
</tr>
<tr>
<td>IOU Cost Savings</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>O&amp;M</td>
<td>4,359</td>
<td>2,355</td>
<td>2,737</td>
</tr>
<tr>
<td>Purchased Power</td>
<td>12,930</td>
<td>1,521</td>
<td>2,431</td>
</tr>
<tr>
<td>Net Impact</td>
<td>(8,033)</td>
<td>920</td>
<td>464</td>
</tr>
</tbody>
</table>

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.
8 Appendix B: Works Cited


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*.


Royer, Jeffrey S. “Assessing the Ability of Rural Electric Cooperatives to Retire Capital Credits.” University of Nebraska – Lincoln, Faculty Publications: Agricultural Economics. August 2016.


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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<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
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</thead>
<tbody>
<tr>
<td>CGS</td>
<td>Customer Grid Supply</td>
</tr>
<tr>
<td>DBEDT</td>
<td>Department of Business, Economic Development, and Tourism</td>
</tr>
<tr>
<td>DER</td>
<td>Distributed energy resources</td>
</tr>
<tr>
<td>DG</td>
<td>Distributed generation</td>
</tr>
<tr>
<td>DR</td>
<td>Demand response</td>
</tr>
<tr>
<td>EV</td>
<td>Electric vehicle</td>
</tr>
<tr>
<td>HECO</td>
<td>Hawaii Electric Company</td>
</tr>
<tr>
<td>HELCO</td>
<td>Hawaii Electric Light Company</td>
</tr>
<tr>
<td>IOU</td>
<td>Investment-owned utility</td>
</tr>
<tr>
<td>KIUC</td>
<td>Kauai Island Utility Cooperative</td>
</tr>
<tr>
<td>LEI</td>
<td>London Economics International LLC</td>
</tr>
<tr>
<td>MECO</td>
<td>Maui Electric Company</td>
</tr>
<tr>
<td>NARUC</td>
<td>National Association of Regulatory Utility Commissioners</td>
</tr>
<tr>
<td>NEM</td>
<td>Net Energy Metering</td>
</tr>
<tr>
<td>PSIP</td>
<td>Power System Improvement Plans</td>
</tr>
<tr>
<td>PUC</td>
<td>Public Utilities Commission</td>
</tr>
<tr>
<td>PV</td>
<td>Photovoltaic</td>
</tr>
<tr>
<td>RPS</td>
<td>Renewable Portfolio Standards</td>
</tr>
<tr>
<td>SB</td>
<td>Single Buyer</td>
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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:

- 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;

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. 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.

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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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.


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](image)

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, 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 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

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5 Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).


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.

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\(^8\) 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

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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:

- 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.

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. 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.].


In their annual reports submitted to the PUC, the HECO Companies and Kauai Island Utility Cooperative ("KIUC") indicate that they are on track to achieve the RPS targets given the current regulations. 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. Figure 4 shows RPS target and the projected RPS of the subsidiaries of the HECO Companies.

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.

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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.


### 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, 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 5. RPS status of the utilities as of 2016

<table>
<thead>
<tr>
<th>Entity</th>
<th>HECO</th>
<th>HELCO</th>
<th>MECO</th>
<th>HEI Consolidated</th>
<th>KIUC</th>
</tr>
</thead>
<tbody>
<tr>
<td>RPS %</td>
<td>19.4%</td>
<td>54.2%</td>
<td>36.9%</td>
<td>25.8%</td>
<td>41.7%</td>
</tr>
</tbody>
</table>


#### Figure 6. Different definitions and technologies considered as DER

<table>
<thead>
<tr>
<th>Entity</th>
<th>DER definition and technologies</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric Power Research Institute (&quot;EPRI&quot;)</td>
<td>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)</td>
</tr>
<tr>
<td>National Association of Regulatory Utility Commissioners (&quot;NARUC&quot;)</td>
<td>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</td>
</tr>
<tr>
<td>Lawrence Berkeley National Laboratory (&quot;LBNL&quot;)</td>
<td>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.</td>
</tr>
<tr>
<td>Massachusetts</td>
<td>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</td>
</tr>
<tr>
<td>Hawaii</td>
<td>DER are modular electric generation or storage located near the point of use and can</td>
</tr>
</tbody>
</table>

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?

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• 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

<table>
<thead>
<tr>
<th>Voltage level</th>
<th>Location of connection</th>
</tr>
</thead>
<tbody>
<tr>
<td>Size</td>
<td>Ownership / control</td>
</tr>
<tr>
<td>Resource and type</td>
<td></td>
</tr>
<tr>
<td>Ownership / control</td>
<td></td>
</tr>
<tr>
<td>Ownership / control</td>
<td></td>
</tr>
<tr>
<td>Resource and type</td>
<td></td>
</tr>
<tr>
<td>Size</td>
<td>Ownership / control</td>
</tr>
<tr>
<td>Voltage level</td>
<td>Location of connection</td>
</tr>
</tbody>
</table>

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 renewables.

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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,\(^\text{18}\) energy security,\(^\text{19}\) 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.\(^\text{20}\)

Based on the HECO Companies’ PSIP Update Report,\(^\text{21}\) 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.


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; KIUC website.

Figure 10. Existing rooftop solar capacity

<table>
<thead>
<tr>
<th></th>
<th>HECO</th>
<th>HELCO</th>
<th>MECO</th>
<th>KIUC</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>DG-PV (2017)</strong></td>
<td>479 MW</td>
<td>103 MW</td>
<td>119 MW</td>
<td>22 MW</td>
</tr>
</tbody>
</table>

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.\textsuperscript{22} There are an additional 5 MW of customer solar under construction or permitted.\textsuperscript{23} The total cumulative residential rooftop solar installations are about 3,390 units, which represents nearly 13\% of KIUC customers.\textsuperscript{24} Although KIUC does not have any publicly available forecasts of DG-PV capacity,\textsuperscript{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).”\textsuperscript{26} The total curtailment of its cost-effective KRS One and KRS Two facilities\textsuperscript{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.\textsuperscript{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.”\textsuperscript{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.

\subsection*{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


\textsuperscript{24} KIUC. \textit{2016 Annual Report}. page 8.

\textsuperscript{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.


\textsuperscript{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 \textit{KIUC Consolidated Financial Statements December 31, 2016 and 2015} (page 8).


\textsuperscript{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. 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. 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%. 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.

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31 Ibid.

Figure 11. The HECO Companies’ forecast cumulative behind-the-meter storage capacity

![Graph showing forecast cumulative behind-the-meter storage capacity for HECO Companies.]

Source: HECO Companies. PSIP Update Report.

Figure 12. Location of the HECO Companies’ planned/under development energy storage

![Map showing location of planned/under development energy storage projects for HECO Companies.]

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.

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.
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](image)

*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).

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\(^{37}\) Tokioka, Beth. KIUC Communications Manager. Email dated April 3, 2018.

\(^{38}\) Ibid.

\(^{39}\) Ibid.
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.

![Projected cumulative EE installation by the island](image)

**Figure 14. Projected cumulative EE installation by the island**

![Graph showing cumulative EE installation by island]

*Source: HECO Companies. PSIP Update Report.*

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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. Also, the forecasts included the effect from Hawaii Energy’s EE programs and changes to building and manufacturing codes and standards.

### 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**

![Graph showing the number of registered passengers EVs by county from 2006 to 2017.](attachment:image.png)

*Source: DBEDT*

EV adoption in Hawaii has been on the rise, climbing from 108 registered passenger EVs in 2006 to 5,987 in 2017. 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.

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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**

![Graph showing EV adoption forecast](image)

*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

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46 Drive Electric Hawaii Initiative “Memorandum of Understanding”, London Economics International LLC
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.

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.” 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.

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.


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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. 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’s 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.”

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. 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 third largest generator unit out for any reason plus its third largest generator unit for scheduled maintenance.

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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.\textsuperscript{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.”\textsuperscript{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.\textsuperscript{55}


\textsuperscript{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.\textsuperscript{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:\textsuperscript{58}

- \textit{Avoided costs}: energy and demand bill management for customers;
- \textit{Resiliency}: critical power support or mitigation during power outages;
- \textit{Reliability}: improvement in power quality;
- \textit{Revenues}: compensation to customers by grid operators or providers for services; and
- \textit{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.\textsuperscript{59}

Hawaii State also offers tax credits for DG technologies, which further incentivizes the uptake of DER.\textsuperscript{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.

\textsuperscript{56} NARUC. \textit{Distributed Energy Resources Rate Design and Compensation}. November 2016.


\textsuperscript{58} DNV GL. \textit{A Review of Distributed Energy Resources}. September 2014.


\textsuperscript{60} Center for the New Energy Economy. \textit{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>


\(^{65}\) “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.”

- **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

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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.” There is also a program called “Renewable Energy Permitting Wizard” 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.” 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.” 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.” 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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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**

![Figure 17](image.png)

*Note: Solid lines represent median prices, while shaded areas show 20\(^{th}\) to 80\(^{th}\) 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.

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.

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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

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\(^81\) 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. 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.

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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.
7  Appendix B: Works Cited


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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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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 criteria³ listed in Figure 1.

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1 Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).


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).

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\(^4\) 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.

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.

<table>
<thead>
<tr>
<th>Area</th>
<th>Over-forecasting</th>
<th>Under-forecasting</th>
</tr>
</thead>
<tbody>
<tr>
<td>Financial forecasting</td>
<td>• Likelihood of stranded assets</td>
<td>• Likelihood of disruptions in electric service</td>
</tr>
<tr>
<td>Generation planning</td>
<td>• Investing in more generation capacity than necessary</td>
<td>• Not investing in sufficient generation capacity</td>
</tr>
<tr>
<td></td>
<td>• Reliability ensured but at high costs</td>
<td>• Lower expenses are more than offset by economic costs of worsening reliability</td>
</tr>
<tr>
<td>Transmission planning</td>
<td>• Excessive investments in transmission lines or capacity</td>
<td>• Investing in fewer or lower capacity transmission lines</td>
</tr>
<tr>
<td></td>
<td>• Reliability ensured but at high costs</td>
<td>• Worsening reliability and congestion</td>
</tr>
<tr>
<td>Distribution planning</td>
<td>• Excessive buildout of distribution infrastructure</td>
<td>• Not building sufficient distribution infrastructure</td>
</tr>
<tr>
<td></td>
<td>• High costs to ensure reliability</td>
<td>• Worse reliability</td>
</tr>
<tr>
<td>Cost of service allocation</td>
<td>• Customer segments for whom load is over-forecasted incorrectly get allocated higher costs</td>
<td>• Customer segments for whom load is under-forecasted get cross-subsidized</td>
</tr>
<tr>
<td>Rate design</td>
<td>• Over-forecasting electric sales results in rates that may not be sufficient to cover costs</td>
<td>• Under-forecasting electric sales results in rates that may be set too high</td>
</tr>
</tbody>
</table>

## 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

<table>
<thead>
<tr>
<th>Weather</th>
<th>Macroeconomic factors (population or economy)</th>
<th>Conservation, energy efficiency, and demand response</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proliferation of distributed generation</td>
<td>Adoption of electric vehicles</td>
<td>Progress of energy storage</td>
</tr>
</tbody>
</table>

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**

<table>
<thead>
<tr>
<th>Top-down Load Forecasting</th>
<th>Bottom-up Load Forecasting</th>
</tr>
</thead>
<tbody>
<tr>
<td>Typical Process</td>
<td></td>
</tr>
<tr>
<td>Develop weather indices</td>
<td>Conduct a local planning study to come up with local load forecast</td>
</tr>
<tr>
<td>Develop macro economic indices</td>
<td>Aggregate/roll up to corporate level</td>
</tr>
<tr>
<td>Develop model(s) for each revenue class</td>
<td>Converts the bottom-up load forecasts to revenue class forecasts</td>
</tr>
<tr>
<td>Develop scenarios</td>
<td></td>
</tr>
<tr>
<td>Develop scenario based load forecasts for each revenue class</td>
<td></td>
</tr>
</tbody>
</table>

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)


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. According to the PSIP, economic growth is “typically the most influential factor when forecasting long-term changes in sales and peak demand.” 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.

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...
aggregate control area loads. 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.

**Figure 7. Projected gross peak load by island from PSIP**

![Graph showing projected gross peak load by island from 2017 to 2045](image)


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

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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


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

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\(^9\) Ibid.

projected that these changes would enable Hawaii to meet its long-term energy efficiency goal in 2030.\textsuperscript{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.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure9.png}
\caption{Projected cumulative EE installation by island}
\end{figure}


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.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure10.png}
\caption{Reduced energy generation from EE}
\end{figure}

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.\footnote{PSIP Update Report: December 2016. page H-4.}

The HECO Companies’ projected DG-PV using a bottom-up analysis by aggregating each company’s tarifed 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.\footnote{PSIP Update Report: December 2016. page J-25.} 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.

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\textbf{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
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](image)


### 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.\(^{14}\)

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.\(^{15}\)

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\(^{15}\) 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-
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.

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)

<table>
<thead>
<tr>
<th>Gross energy consumption</th>
<th>EE</th>
<th>DG-PV</th>
<th>EV</th>
<th>Net energy sales</th>
</tr>
</thead>
<tbody>
<tr>
<td>11,652</td>
<td>1,433</td>
<td>1,144</td>
<td>46</td>
<td>9,121</td>
</tr>
</tbody>
</table>

Figure 14. Projected net peak load by island from PSIP

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%.\textsuperscript{16} From 2031 onwards, the net peak load is expected to grow at a CAGR of 0.8% annually.

\textbf{Figure 15. Projected net energy consumption by island from PSIP}

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure15}
\caption{Projected net energy consumption by island from PSIP}
\end{figure}


5 Load forecast for the Kauai County

KIUC does not have any publicly available load forecasts for the county of Kauai. 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.

![Figure 16. Historical and projected gross peak load and energy consumption for Kauai](image)

Source: Kauai Island Utility Cooperative Annual Reports to PUC; UHERO; LEI analysis

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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


\(^{20}\) 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.


\(^{26}\) 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 Calculated using population data from DBEDT data warehouse.

**Figure 17.** Projected cumulative installation and generation impact of EE for Kauai


**Figure 18.** Projected DG-PV generation for Kauai

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**

![Graph showing projected net peak load and energy consumption for Kauai](image)

Source: LEI analysis

Note: Net peak load and energy consumption represent peak load and energy consumption after adjustment of EE, DG-PV, and EV.

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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](image)

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

![Graph showing projected gross energy consumption for Hawaii islands]


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


Figure 23. Projected generation impact from EE for the State of Hawaii

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

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).
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.\textsuperscript{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**

![Graph of energy consumption by customer type]


### 6.4 Number of customers

As of 2016, the total number of customers for the State of Hawaii is 496,048 customers.\textsuperscript{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.


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


HECO. Form 10-K For the fiscal year ended December 31, 2016.


HELCO. Annual Report to the PUC of Hawaii for the year ending December 31, 2016.


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.

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 on 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**

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<th>Acronym</th>
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<tr>
<td>CAPM</td>
<td>Capital Asset Pricing Model</td>
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<tr>
<td>CFC</td>
<td>Cooperative Finance Corporation</td>
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<td>CIAC</td>
<td>Contributions in Aid of Construction</td>
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<td>DBEDT</td>
<td>Hawaii Department of Business, Economic Development, and Tourism</td>
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<tr>
<td>EIA</td>
<td>Energy Information Administration</td>
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<tr>
<td>EBIT</td>
<td>Earnings Before Interest and Taxes</td>
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<td>GAPP</td>
<td>Generally Accepted Accounting Principles</td>
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<td>HECO</td>
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<td>HELCO</td>
<td>Hawaii Electric Light Company</td>
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<td>IC</td>
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<td>IFRS</td>
<td>International Financial Reporting Standards</td>
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<td>IOU</td>
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<td>IPP</td>
<td>Independent Power Producer</td>
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<td>Internal Revenue Service</td>
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<td>kWh</td>
<td>Kilowatt-hour</td>
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<td>Kauai Island Utility Cooperative</td>
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<td>LCOE</td>
<td>Levelized Cost of Electricity</td>
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<td>London Economics International LLC</td>
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<td>MECO</td>
<td>Maui Electric Company</td>
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<td>NARUC</td>
<td>National Association of Regulatory Utility Commissioners</td>
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<tr>
<td>NOPAT</td>
<td>Net Operating Profits After Tax</td>
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<td>NREL</td>
<td>National Renewable Energy Laboratory</td>
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<tr>
<td>Abbreviation</td>
<td>Description</td>
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<tr>
<td>O&amp;M</td>
<td>Operations and Maintenance</td>
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<td>United States Department of Agriculture</td>
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<td>WACC</td>
<td>Weighted Average Cost of Capital</td>
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<td>Yield to Maturity</td>
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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 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)](image)

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)

![Graph showing projected revenue requirements for Hawaii County by ownership model from 2017 to 2045.]

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. 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.
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.

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 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, was 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 listed in Figure 5.

![Figure 5. State’s key criteria for evaluating the models](source: Scope of Services under Contract No. 65595)

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2 Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).


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.\footnote{Hawaii Contract No. 65595. Scope of Services.}

### 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.
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](image)

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

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.

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.

---

**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.”

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.” 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,” 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:

\[ \text{WACC} = D \times R_D + (1-D) \times R_E \]

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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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, \( \beta \) (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.

---

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:

\[
TIER = \frac{EBIT}{(Interest\ Expense)}
\]

\[
TIER = \frac{(Interest\ Expense +\ Margins)}{(Interest\ Expense)}
\]

\[
TIER = \frac{(Revenues -\ Operating\ Expenses)}{(Interest\ Expense)}
\]

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. 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:

\[
TIER = \frac{(\text{Revenues} - \text{Operating Expenses})}{\text{(Interest Expense)}}
\]

\[
\text{Revenues} - \text{Operating Expenses} = \text{Interest Expense} \times TIER
\]

\[
\text{Revenue Requirement} = \text{Interest Expense} \times TIER + \text{Operating Expense}
\]

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.

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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, 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. Subsequently, the capex will be incurred periodically as the assets are replaced or upgraded.

3) **System planning and procurement – O&M costs**

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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.

<table>
<thead>
<tr>
<th>IOU</th>
<th>Co-op</th>
<th>SB (outside)</th>
<th>SB (inside)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Revenue determination</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Allowed return on rate base</td>
<td>Set coverage ratio on interest payments</td>
<td>All expenses passed on to the utility through a separate charge and ultimately to the consumers</td>
<td>All expenses added to utility revenue requirement</td>
</tr>
<tr>
<td></td>
<td>Margins on expenses assigned to members’ patronage accounts</td>
<td></td>
<td>IOU can rate base the SB’s assets</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>SB capex increases the co-op’s debt</td>
</tr>
<tr>
<td><strong>Source of capital</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Debt and equity capital markets</td>
<td>Low-cost debt from co-op-specific lenders</td>
<td>SB fees charged to the utility</td>
<td>Through the utility</td>
</tr>
<tr>
<td></td>
<td>Equity from members as patronage capital</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Cost of capital</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>WACC (based on market rates for debt and equity)</td>
<td>Interest-rate of debt</td>
<td>N/A</td>
<td>Through the utility</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Revenue requirement components</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rate base * WACC + opex</td>
<td>Interest exp * TIER + opex</td>
<td>Purchased power cost + SB capex + SB opex + Rent + audit</td>
<td>Purchased power cost + SB opex + Rent + audit (SB capex included in IOU rate base)</td>
</tr>
</tbody>
</table>
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](image-url)
1. Rate base was estimated from its components.

\[ \text{Rate Base} = \text{Investment in Assets} - \text{Funds from NonInvestors} + \text{Working Cash Required} \]

**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"), customer advances, customer deposits, accumulated deferred income taxes, unamortized state Investment Tax Credit ("ITC"), and other regulatory liabilities

- Accumulated deferred income taxes are calculated using each year’s net increase/decrease based on:

\[ \text{Deferred Income Tax} = (\text{Tax depreciation} - \text{Book depreciation}) \times \text{Effective Tax Rate} \]

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.

\[ \text{Revenue Requirement} = \text{Rate Base} \times \text{WACC} + \text{Operating Expense} \]

4.1.2 Status quo - KIUC\textsuperscript{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\textsuperscript{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.

\textsuperscript{18} For Kauai County.

\textsuperscript{19} For Honolulu, Hawaii, and Maui counties.
4.1.4 IOU to SB (outside)\textsuperscript{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)\textsuperscript{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\textsuperscript{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.\textsuperscript{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.\textsuperscript{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.

\textsuperscript{20} For Honolulu, Hawaii, and Maui counties.

\textsuperscript{21} For Honolulu, Hawaii, and Maui counties.

\textsuperscript{22} For Kauai county.


\textsuperscript{24} See past transaction examples in Task 1.2.2.

\textsuperscript{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

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Assumptions</th>
</tr>
</thead>
</table>
| 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 Plan (“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

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Debt tenor</td>
<td>The debt tenor for co-ops was based on KIUC’s audited financial statements.</td>
</tr>
<tr>
<td>Interest rate on debt</td>
<td>The interest rate on co-op debt was estimated in Task 1.4.2, based on KIUC’s recent interest payments.</td>
</tr>
<tr>
<td>New capex debt-capital ratio</td>
<td>The analysis assumes that the new co-op finances its capex with 100% debt.</td>
</tr>
<tr>
<td>TIER level</td>
<td>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.</td>
</tr>
<tr>
<td>Regular patronage capital retirement</td>
<td>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%.</td>
</tr>
<tr>
<td>Co-op board training expense (annual)</td>
<td>The annual expenses for board members’ training is based on KIUC’s actual expenses, provided by Beth Tokioka from KIUC via email.</td>
</tr>
<tr>
<td>Effective income tax rate</td>
<td>The effective state income tax rate remains unchanged. The Project Team assumes that the new co-op will be exempt from federal income taxes.</td>
</tr>
</tbody>
</table>

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

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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. 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.

<table>
<thead>
<tr>
<th>($000s)</th>
<th>HEI Overhead</th>
<th>HECO Overhead</th>
<th>Total Overhead</th>
</tr>
</thead>
<tbody>
<tr>
<td>HECO</td>
<td>4,663</td>
<td>-</td>
<td>4,663</td>
</tr>
<tr>
<td>HELCO</td>
<td>742</td>
<td>20,576</td>
<td>21,318</td>
</tr>
<tr>
<td>MECO</td>
<td>752</td>
<td>20,053</td>
<td>20,805</td>
</tr>
</tbody>
</table>


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.

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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)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td>System planning and procurement expense</td>
<td>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.</td>
</tr>
<tr>
<td>IOU-SB overlap</td>
<td>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)</td>
</tr>
<tr>
<td>Rent</td>
<td>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.</td>
</tr>
<tr>
<td>SB Audits</td>
<td>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.</td>
</tr>
<tr>
<td>Decrease in purchased power costs</td>
<td>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.</td>
</tr>
</tbody>
</table>

### 4.2.4 IOU to SB (inside)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td>SB capex</td>
<td>The capex of an SB consists of expenditure on: - Furniture &amp; equipment - Leasehold improvements - Computers - AV equipment - Telephone system</td>
</tr>
<tr>
<td></td>
<td>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.</td>
</tr>
<tr>
<td>SB capex - asset life (years)</td>
<td>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</td>
</tr>
<tr>
<td>System planning and procurement expense</td>
<td>See above [Section 0 - IOU to SB (outside)]</td>
</tr>
<tr>
<td>IOU-SB overlap</td>
<td>See above [Section 0]</td>
</tr>
<tr>
<td>Rent</td>
<td>See above [Section 0]</td>
</tr>
<tr>
<td>Decrease in purchased power costs</td>
<td>See above [Section 0]</td>
</tr>
</tbody>
</table>
## 4.2.5 KIUC

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Status Quo (Co-op)</strong></td>
<td></td>
</tr>
<tr>
<td>Cost of capital</td>
<td>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.</td>
</tr>
<tr>
<td>Debt term</td>
<td>The debt tenor for co-ops was based on KIUC’s audited financial statements.</td>
</tr>
<tr>
<td>Debt-capital ratio</td>
<td>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.</td>
</tr>
<tr>
<td>TIER level</td>
<td>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.</td>
</tr>
<tr>
<td>Regular patronage capital retirement</td>
<td>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%.</td>
</tr>
<tr>
<td>Effective income tax rate</td>
<td>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.</td>
</tr>
<tr>
<td>Taxes other than income taxes (revenue taxes)</td>
<td>Revenue tax rates are the same as for IOU. [see Section 4.2.1 – Status Quo – HECO/MECO/HELCO]</td>
</tr>
<tr>
<td>Hawaii cost index (vs. the overall United States)</td>
<td>Same as for IOU. [see Section 4.2.1]</td>
</tr>
<tr>
<td>Power plant life (years)</td>
<td>Same as for IOU. [see Section 4.2.1]</td>
</tr>
<tr>
<td>Plant depreciation rates</td>
<td>Depreciation rates for KIUC’s asset categories (Production, T&amp;D, General, Vehicles) were taken from KIUC Depreciation Study.</td>
</tr>
<tr>
<td>Regular plant retirements (% of BoY plant balance)</td>
<td>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.</td>
</tr>
<tr>
<td>Annual plant O&amp;M cost escalation</td>
<td>Same as for IOU. [see Section 3.2.2.1]</td>
</tr>
<tr>
<td>Annual capacity factor decrease</td>
<td>Estimated at 1% for renewables and 10% for thermal, to align generation by fuel type with KIUC’s RPS goals.</td>
</tr>
<tr>
<td>Thermal plant efficiency loss</td>
<td>Same as for IOU. [see Section 3.2.2.1]</td>
</tr>
<tr>
<td><strong>Co-op to IOU</strong></td>
<td></td>
</tr>
<tr>
<td>Cost of capital</td>
<td>The capital costs for the new IOU were obtained by averaging the rates of return of HECO, MECO, and HELCO.</td>
</tr>
<tr>
<td>Co-op to SB (outside)</td>
<td></td>
</tr>
<tr>
<td>-----------------------------------------------------------</td>
<td>-----------------------------------------------------------------</td>
</tr>
<tr>
<td>System planning and procurement expense</td>
<td>System planning and procurement expense assumed that KIUC is</td>
</tr>
<tr>
<td></td>
<td>approximately half the size of MECO, based on customers and sales.</td>
</tr>
<tr>
<td>Co-op-SB overlap</td>
<td>Same as for IOU to SB. [see Section 0]</td>
</tr>
<tr>
<td>Rent</td>
<td>Based on the assumption that KIUC is approximately half the size of MECO.</td>
</tr>
<tr>
<td>SB Audits</td>
<td>Same as for IOU to SB. [see Section 0]</td>
</tr>
<tr>
<td>Decrease in purchased power costs</td>
<td>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.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Co-op to SB (inside)</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>SB capex</td>
<td>Same as for IOU to SB [see Section 4.2.4], with the assumption that KIUC is approximately half the size of MECO.</td>
</tr>
<tr>
<td>SB capex – asset life (years)</td>
<td>Same as for IOU to SB [see Section 4.2.4].</td>
</tr>
<tr>
<td>System planning and procurement expense</td>
<td>Same as for IOU to SB [see Section 4.2.4], with the assumption that KIUC is approximately half the size of MECO.</td>
</tr>
<tr>
<td>Co-op-SB overlap</td>
<td>Same as for IOU to SB [see Section 4.2.4].</td>
</tr>
<tr>
<td>Rent</td>
<td>Same as for IOU to SB [see Section 4.2.4], with the assumption that KIUC is approximately half the size of MECO.</td>
</tr>
<tr>
<td>Decrease in purchased power costs</td>
<td>See above [Co-op to SB (outside)]</td>
</tr>
</tbody>
</table>
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; 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)](image)

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.

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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.
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](image)

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. Projected revenue requirements are higher under the co-op model throughout the forecast horizon due to the adjustment for capex and debt repayment.

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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.
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

<table>
<thead>
<tr>
<th>IOU Sensitivities - change in interest rate on long-term debt</th>
<th>Coop Sensitivities - change in interest rate on long-term debt</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.00%</td>
<td>1.00%</td>
</tr>
<tr>
<td>25,000</td>
<td>12,500</td>
</tr>
<tr>
<td>2017</td>
<td>2030</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>SB (outside) Sensitivities - change in purchased power cost reduction</th>
<th>SB (inside) Sensitivities - change in purchased power cost reduction</th>
</tr>
</thead>
<tbody>
<tr>
<td>3%</td>
<td>2.50%</td>
</tr>
<tr>
<td>0</td>
<td>(1,000)</td>
</tr>
<tr>
<td>2017</td>
<td>2030</td>
</tr>
</tbody>
</table>

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. 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.

A slightly different set of sensitivity analyses were conducted for 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
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.
### Appendix B: Assumptions used in the model

#### 7.1 IOU (status quo)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Assumptions</th>
<th>Source</th>
</tr>
</thead>
</table>
| **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%  
| **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% | |
| **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 |
<table>
<thead>
<tr>
<th>Regular plant retirements (% of BoY plant balance)</th>
<th>HELCO</th>
<th>MECO</th>
<th>HECO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production</td>
<td>2.519%</td>
<td>2.224%</td>
<td>0.764%</td>
</tr>
<tr>
<td>T&amp;D</td>
<td>3.650%</td>
<td>0.316%</td>
<td>0.697%</td>
</tr>
<tr>
<td>General</td>
<td>5.782%</td>
<td>4.719%</td>
<td>0.234%</td>
</tr>
<tr>
<td>Vehicles</td>
<td>6.721%</td>
<td>9.475%</td>
<td>5.387%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>HELCO rate case (Docket No. 2016-0328)</th>
<th>an average of 2011-2015 data</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Annual plant O&amp;M cost escalation</th>
<th>0.25%</th>
<th>Industry standards</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual capacity factor decrease</td>
<td>Renewables - 1%</td>
<td>To match HECO’s projections of generation output by fuel type in the PSIP.</td>
</tr>
<tr>
<td></td>
<td>Thermal - 5%</td>
<td></td>
</tr>
<tr>
<td>Thermal plant efficiency loss</td>
<td>2% every five years</td>
<td>To match HECO’s projections of generation output from thermal plants in the PSIP.</td>
</tr>
</tbody>
</table>

### 7.2 IOU to Co-op

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Assumptions</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Debt tenor</td>
<td>25 years</td>
<td>KIUC Audited Financial Statement 2003</td>
</tr>
<tr>
<td>Interest rate on debt</td>
<td>4.10%</td>
<td>Task 1.4.2, Figure 24</td>
</tr>
<tr>
<td>Target debt-capital ratio</td>
<td>70%</td>
<td>KIUC rate case</td>
</tr>
</tbody>
</table>
### 7.3 IOU to SB (outside)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Assumptions</th>
<th>Source</th>
</tr>
</thead>
</table>
| System planning and procurement expense | HECO - $9,738,000  
MEOC - $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  
MEOC - $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)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Assumptions</th>
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<td>SB capex</td>
<td>HECO</td>
<td>Task 1.4.2, Figure 31</td>
</tr>
<tr>
<td></td>
<td>MEOC</td>
<td></td>
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<tr>
<td></td>
<td>HELCO</td>
<td></td>
</tr>
<tr>
<td></td>
<td>HECO</td>
<td></td>
</tr>
<tr>
<td></td>
<td>MEOC</td>
<td></td>
</tr>
<tr>
<td></td>
<td>HELCO</td>
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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%.
<table>
<thead>
<tr>
<th>SB capex – asset life (years)</th>
<th>System planning and procurement expense</th>
<th>IOU-SB overlap</th>
<th>Rent</th>
<th>Decrease in purchased power costs</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td><strong>HECO</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Furniture &amp; equipment – 10</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Leasehold improvements – 40</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Computers – 3</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>AV equipment – 10</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Telephone system – 5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>MECO</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Furniture &amp; equipment – 10</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td></td>
<td>Leasehold improvements – 40</td>
<td></td>
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<tr>
<td></td>
<td>Computers – 3</td>
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<td>AV equipment – 10</td>
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<td></td>
<td>Telephone system – 5</td>
<td></td>
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<tr>
<td></td>
<td><strong>HELCO</strong></td>
<td></td>
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</tr>
<tr>
<td></td>
<td>Furniture &amp; equipment – 10</td>
<td></td>
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<td></td>
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<tr>
<td></td>
<td>Leasehold improvements – 40</td>
<td></td>
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<tr>
<td></td>
<td>Computers – 3</td>
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<td></td>
<td>AV equipment – 10</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td></td>
<td>Telephone system – 5</td>
<td></td>
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<tr>
<td></td>
<td><strong>Telephone system – $33,000</strong></td>
<td></td>
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<tr>
<td></td>
<td><strong>HECO</strong></td>
<td></td>
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<td></td>
<td>$8,717,000</td>
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<td></td>
<td><strong>MECO</strong></td>
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</tr>
<tr>
<td></td>
<td>$4,709,000</td>
<td></td>
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<td></td>
<td><strong>HELCO</strong></td>
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<td>$5,473,000</td>
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<td><strong>Task 1.4.2, Figure 31</strong></td>
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<td></td>
<td><strong>Task 1.4.2, Figure 37</strong></td>
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<td><strong>Task 1.4.2, Section 5.2.2.1</strong></td>
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<tr>
<td></td>
<td><strong>Task 1.4.2, Figure 34</strong></td>
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<td></td>
<td><strong>Task 1.4.2, Section 5.2.2.3</strong></td>
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</table>

Task 1.4.2, Section 5.2.2.1

Rent

Decrease in purchased power costs

Task 1.4.2, Section 5.2.2.3
### 7.5 KIUC

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Assumptions</th>
<th>Source</th>
</tr>
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<tr>
<td><strong>Cost of capital</strong></td>
<td>Long-term debt – 4.10% (average of 2013 – 2016 ratio of interest expense to beginning-of-year long-term debt)</td>
<td>KIUC Annual Report to PUC 2016</td>
</tr>
<tr>
<td><strong>Debt term</strong></td>
<td>25 years</td>
<td>Task 1.4.2, Figure 24</td>
</tr>
<tr>
<td><strong>Debt-capital ratio</strong></td>
<td>Current – 65.3%</td>
<td>KIUC Annual Report to PUC 2016</td>
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<tr>
<td><strong>TIER level</strong></td>
<td>2.00</td>
<td>KIUC rate case (Docket No. 2009-0050)</td>
</tr>
<tr>
<td><strong>Regular patronage capital retirement</strong></td>
<td>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%.</td>
<td>Stakeholder feedback</td>
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<tr>
<td><strong>Effective income tax rate</strong></td>
<td>Federal – 0%</td>
<td>HECO/MECO/HELCO rate cases</td>
</tr>
<tr>
<td><strong>Taxes other than income taxes (revenue taxes)</strong></td>
<td>Public Service Tax – 5.885%</td>
<td>KIUC Annual Report to PUC 2016</td>
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<tr>
<td><strong>Inflation rate</strong></td>
<td>2%</td>
<td>EIA – State Energy Data System 2016 (motor gasoline average price, all sectors)</td>
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<tr>
<td><strong>Hawaii cost index</strong></td>
<td>1.32</td>
<td></td>
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<tr>
<td><strong>Capex financing</strong></td>
<td>65% – debt</td>
<td></td>
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<tr>
<td><strong>Power plant life (years)</strong></td>
<td>Solar PV – 25</td>
<td></td>
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<tr>
<td><strong>Plant depreciation rates</strong></td>
<td>Wind – 30</td>
<td>KIUC Depreciation Study</td>
</tr>
<tr>
<td><strong>Regular plant retirements (% of BoY plant balance)</strong></td>
<td>Production – 1.367%</td>
<td>KIUC Annual Reports to PUC 2012 – 2016</td>
</tr>
<tr>
<td><strong>Annual plant O&amp;M cost escalation</strong></td>
<td>0.25%</td>
<td></td>
</tr>
<tr>
<td><strong>Annual capacity factor decrease</strong></td>
<td>Renewables – 1%</td>
<td>For thermal plants, adjusted to meet KIUC RPS goals</td>
</tr>
<tr>
<td><strong>Plant – 2.990%</strong></td>
<td>T&amp;D – 2.729%</td>
<td></td>
</tr>
<tr>
<td><strong>General – 3.170%</strong></td>
<td>Vehicles – 6.400%</td>
<td></td>
</tr>
<tr>
<td><strong>Vehicles – 6.400%</strong></td>
<td></td>
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</tr>
<tr>
<td><strong>Vehicles – 2.857%</strong></td>
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</tr>
<tr>
<td><strong>Production – 2.990%</strong></td>
<td></td>
<td></td>
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<tr>
<td><strong>T&amp;D – 2.729%</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>General – 3.170%</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Vehicles – 6.400%</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Thermal plant efficiency loss</strong></td>
<td>2% every 5 years</td>
<td></td>
</tr>
<tr>
<td>----------------------------------</td>
<td>-----------------</td>
<td></td>
</tr>
</tbody>
</table>

**Co-op to IOU**

| Cost of capital | Long-term debt – 5.06%  
|                 | WACC – 8.26%     |
|                 | HECO/MECO/HELCO average |

**Co-op to SB (outside)**

<table>
<thead>
<tr>
<th>System planning and procurement expense</th>
<th>$2,465,000</th>
</tr>
</thead>
<tbody>
<tr>
<td>Co-op-SB overlap</td>
<td>50% (degree of SB capabilities that co-op retains)</td>
</tr>
<tr>
<td>Rent</td>
<td>$23,000</td>
</tr>
<tr>
<td>SB Audits</td>
<td>$15,000</td>
</tr>
<tr>
<td>Decrease in purchased power costs</td>
<td>0% (co-ops have the incentive to minimize costs to members)</td>
</tr>
</tbody>
</table>

**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 |
| SB capex – asset life (years) | Furniture & equipment – 10  
|                             | Leasehold improvements – 40  
|                             | Computers – 3  
|                             | AV equipment – 10  
|                             | Telephone system – 5 |
| System planning and procurement expense | $2,355,000 |
| Co-op-SB overlap | 50% (degree of SB capabilities that co-op retains) |
| Rent | $23,000 |
| Decrease in purchased power costs | 0% (co-ops have the incentive to minimize costs to members) |

**Co-op to SB (outside)**

| Task 1.4.2, Section 5.2.2.1 | USDA Rural Development  
|                             | Understanding Cooperatives: Cooperative Business Principles |

**Co-op to SB (inside)**

| Task 1.4.2, Figure 31 | USDA Rural Development  
|                        | Understanding Cooperatives: Cooperative Business Principles |

| assume KIUC is half the size of MECO |
| Task 1.4.2, Section 5.2.2.2 | USDA Rural Development  
|                             | Understanding Cooperatives: Cooperative Business Principles |
8 Appendix C: List of works consulted


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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<th>Acronym</th>
<th>Full Form</th>
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<tr>
<td>CAPM</td>
<td>Capital Asset Pricing Model</td>
</tr>
<tr>
<td>CFC</td>
<td>Cooperative Finance Corporation</td>
</tr>
<tr>
<td>CIAC</td>
<td>Contributions in Aid of Construction</td>
</tr>
<tr>
<td>DBEDT</td>
<td>Hawaii Department of Business, Economic Development, and Tourism</td>
</tr>
<tr>
<td>EIA</td>
<td>Energy Information Administration</td>
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<tr>
<td>EBIT</td>
<td>Earnings Before Interest and Taxes</td>
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<tr>
<td>FCFF</td>
<td>Free Cash Flow to the Firm</td>
</tr>
<tr>
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<td>Generally Accepted Accounting Principles</td>
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<tr>
<td>HECO</td>
<td>Hawaiian Electric Company</td>
</tr>
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<td>HELCO</td>
<td>Hawaii Electric Light Company</td>
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<td>Holding Company</td>
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<td>Invested Capital</td>
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<td>International Financial Reporting Standards</td>
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<td>Investor-Owned Utility</td>
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<td>Independent Power Producer</td>
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<td>London Economics International LLC</td>
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<td>MECO</td>
<td>Maui Electric Company</td>
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<td>National Association of Regulatory Utility Commissioners</td>
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<td>Net Operating Profits After Tax</td>
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<td>National Renewable Energy Laboratory</td>
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<td>Power Supply Improvement Plan</td>
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<td>Transmission and Distribution</td>
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<td>Times Interest Earned Ratio</td>
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<td>United States Department of Agriculture</td>
</tr>
<tr>
<td>WACC</td>
<td>Weighted Average Cost of Capital</td>
</tr>
<tr>
<td>YTM</td>
<td>Yield to Maturity</td>
</tr>
</tbody>
</table>
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.

<table>
<thead>
<tr>
<th></th>
<th>IOU</th>
<th>Co-op</th>
<th>SB</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Free Cash Flow to Firm</strong></td>
<td>capex adjustment scenario results in highest FCFF in all counties</td>
<td>negative FCFF in Kauai County for no capex adjustment scenario in more than half of the years of the forecast horizon</td>
<td>very little difference between independent and ring-fenced SB models</td>
</tr>
<tr>
<td></td>
<td>very little difference (&lt;1%) in FCFF between fixed vs. flexible capital scenarios</td>
<td>negative FCFF in Kauai County 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)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>negative through 2019 in Hawaii and Maui Counties and through 2020 in Honolulu County</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>lower than co-op (capex adjustment) in Kauai County</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Cash balance – impact of capital structure or capex adjustment</strong></td>
<td>mostly positive cash balances except in Maui County under both IOU scenarios</td>
<td>negative cash balances in Kauai County for no capex adjustment scenario</td>
<td>generally similar to the underlying utility</td>
</tr>
<tr>
<td></td>
<td>cash balances higher initially (up to 2030s) under fixed capital structure scenario than flexible capital structure scenario</td>
<td>very high growth in cash balances in all counties using capex adjustment scenario - ~14% per year over the forecast horizon</td>
<td></td>
</tr>
<tr>
<td></td>
<td>from co-op to IOU in Kauai County, cash balances are higher using a target capital structure approach</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Returns on equity</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Scenario</td>
<td>Financial risk</td>
<td></td>
<td></td>
</tr>
<tr>
<td>-------------------------------------------------------------------------</td>
<td>---------------------------------------------------------------------------------------------------</td>
<td></td>
<td></td>
</tr>
<tr>
<td>highest using flexible capital structure scenario (no target in Kauai County)</td>
<td>negative cash balance in Maui County, under both fixed and flexible capital structure scenarios</td>
<td></td>
<td></td>
</tr>
<tr>
<td>no difference between w/ vs. w/o capex adjustment scenarios for members</td>
<td>fixed capital structure scenario dilutes equity returns, potentially lowering stock prices and increasing the cost of equity</td>
<td></td>
<td></td>
</tr>
<tr>
<td>no difference vs. status quo co-op in Kauai County</td>
<td>negative cash balances in Kauai County, using no capex adjustment scenario</td>
<td></td>
<td></td>
</tr>
<tr>
<td>slightly higher vs. status quo IOU in Hawaii and Maui counties</td>
<td>similar to the underlying utility (but worse in Maui County)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>higher vs. status quo IOU in Honolulu County until 2025; significantly lower thereafter</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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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<table>
<thead>
<tr>
<th><strong>Accrual Accounting</strong></th>
<th><strong>Cash Basis Accounting</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Overarching approach</strong></td>
<td>Revenues and expenses are recorded as they are earned and incurred, regardless of when cash transfers occur.</td>
</tr>
<tr>
<td><strong>Operations and maintenance expense</strong></td>
<td>Following the overarching approach, operations and maintenance (&quot;O&amp;M&quot;) expenses are recorded in the period in which they are incurred.</td>
</tr>
<tr>
<td><strong>Taxes</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Financing capital improvements</strong></td>
<td>Capital improvements are capitalized or expensed over the life of the asset.</td>
</tr>
<tr>
<td><strong>Depreciation</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Return on invested capital</strong></td>
<td>Return on invested capital (&quot;ROIC&quot;) is calculated by dividing net operating profits after tax (&quot;NOPAT&quot;) by invested capital (&quot;IC&quot;). Earnings before interest and taxes (&quot;EBIT&quot;), an accrual accounting line item, must be converted to align with NOPAT, by multiplying EBIT by 1 minus the tax rate.</td>
</tr>
</tbody>
</table>

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

created using the cash basis approach are not accepted under Generally Accepted Accounting Principles ("GAAP") or International Financial Reporting Standards ("IFRS").

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.

### 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."

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.

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.

### 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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Accounting Method. 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. 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.

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.

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. 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. 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:


16 Ibid.


(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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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.

<table>
<thead>
<tr>
<th></th>
<th>IOU</th>
<th>Co-op</th>
<th>SB (outside)</th>
<th>SB (inside)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>O&amp;M expenses</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Consists of power supply, other labor and non-labor O&amp;M, depreciation, and tax expense.</td>
<td>Generally like the IOU</td>
<td>Tax expense is lower for co-op vs. IOU due to exemption from federal income tax.</td>
<td>Utility retains O&amp;M expenses for general operations, except for expenses related to planning and power procurement</td>
<td>Similar to SB (outside), although some synergies exist because SB is part of the utility</td>
</tr>
<tr>
<td></td>
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<td></td>
</tr>
<tr>
<td><strong>Taxes</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Revenue taxes.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Federal income taxes.</td>
<td>No federal income taxes.</td>
<td>SB O&amp;M expenses change the taxable income for the utility.</td>
<td>SB O&amp;M expenses change the taxable income for the utility.</td>
<td></td>
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<tr>
<td>State income taxes.</td>
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<td></td>
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<tr>
<td><strong>Financing capital improvements</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Debt and equity at market rates.</td>
<td>Low-cost debt from coop-specific sources.</td>
<td>SB-specific capex in the SB-fee charged to the utility.</td>
<td>SB-specific capex financed with utility’s financing options</td>
<td></td>
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<tr>
<td></td>
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<td></td>
</tr>
<tr>
<td><strong>Depreciation</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Based on the original cost of the asset and its useful life.</td>
<td>Based on the original cost of the asset and its useful life.</td>
<td>SB-assets do not affect utility depreciation expense.</td>
<td>SB-assets are included in utility depreciation expense.</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Return on invested capital</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Debt repayment at utility terms.</td>
<td>Debt repayment at coop-specific terms.</td>
<td>SB (outside) mode ldoes not impact ROIC relative to underlying utility (either IOU or co-op).</td>
<td>With co-op, no impact on ROIC.</td>
<td></td>
</tr>
<tr>
<td>Equity investors receive allowed return on rate base.</td>
<td></td>
<td>With IOU, equity investors receive incremental returns on SB assets.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
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.
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.

![Projected cash flows and balances by ownership model – Honolulu County ($MM, nominal)](image)

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...
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
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 deducting 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.

<table>
<thead>
<tr>
<th>Projected NPV of net cash flows to equity (9.5% discount rate(^{21}))</th>
<th>Fixed capital structure</th>
<th>Flexible capital structure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Status Quo</td>
<td>$703 MM</td>
<td>$1,013 MM</td>
</tr>
<tr>
<td>Single Buyer</td>
<td>$736 MM</td>
<td>$1,038 MM</td>
</tr>
<tr>
<td>Co-op</td>
<td>($576 MM)</td>
<td>($576 MM)</td>
</tr>
</tbody>
</table>

\(^{21}\) Cost of equity for all three HECO Companies is 9.5%
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

![Debt-capital ratio graph]

Legend:
- IOU - Fixed capital structure
- IOU - Flexible capital structure
- Co-op
- SB - Fixed capital structure
- SB - Flexible capital structure
5.2 Hawaii County

5.2.1 Cash flows

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.

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 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.

### Table 1. Projected NPV of net cash flows to equity (9.5% discount rate)

<table>
<thead>
<tr>
<th></th>
<th>Fixed capital structure</th>
<th>Flexible capital structure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Status Quo</td>
<td>$138 MM</td>
<td>$234 MM</td>
</tr>
<tr>
<td>Single Buyer</td>
<td>$147 MM</td>
<td>$241 MM</td>
</tr>
<tr>
<td>Co-op</td>
<td>($136 MM)</td>
<td>($136 MM)</td>
</tr>
</tbody>
</table>

Co-op: ($136 MM) column indicates a negative cash flow, indicating the project may not be financially viable under the Co-op model.

### 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.
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.
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.
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.
### Projected NPV of net cash flows to equity (9.5% discount rate)

| Status Quo | Fixed capital structure | $290 MM | Flexible capital structure | $334 MM |
| Single Buyer | Fixed capital structure | $296 MM | Flexible capital structure | $339 MM |
| Co-op | Capex adjustment scenario | ($113 MM) | No capex adjustment scenario | ($113 MM) |

---

**Figure 15. Projected net cash flows to equity – Maui County ($MM, nominal)**

<table>
<thead>
<tr>
<th>Year</th>
<th>IOU - Fixed capital structure</th>
<th>IOU - Flexible capital structure</th>
<th>SB (outside) - Fixed capital structure</th>
<th>SB (outside) - Flexible capital structure</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>0</td>
<td>20</td>
<td>0</td>
<td>20</td>
</tr>
<tr>
<td>2021</td>
<td>20</td>
<td>40</td>
<td>20</td>
<td>40</td>
</tr>
<tr>
<td>2025</td>
<td>40</td>
<td>60</td>
<td>40</td>
<td>60</td>
</tr>
<tr>
<td>2029</td>
<td>60</td>
<td>80</td>
<td>60</td>
<td>80</td>
</tr>
<tr>
<td>2033</td>
<td>80</td>
<td>100</td>
<td>80</td>
<td>100</td>
</tr>
<tr>
<td>2037</td>
<td>100</td>
<td>120</td>
<td>100</td>
<td>120</td>
</tr>
<tr>
<td>2041</td>
<td>120</td>
<td>140</td>
<td>120</td>
<td>140</td>
</tr>
<tr>
<td>2045</td>
<td>140</td>
<td>160</td>
<td>140</td>
<td>160</td>
</tr>
</tbody>
</table>

---

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.
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.
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.
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.

<table>
<thead>
<tr>
<th>Projected NPV of net cash flows to equity (8% discount rate)</th>
<th>Capex adjustment scenario</th>
<th>No capex adjustment scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td>Status Quo (co-op)</td>
<td>($198 MM)</td>
<td>($33 MM)</td>
</tr>
<tr>
<td>Flexible capital structure</td>
<td></td>
<td></td>
</tr>
<tr>
<td>IOU</td>
<td>$125 MM</td>
<td>$91 MM</td>
</tr>
</tbody>
</table>

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.
Appendix B: List of works consulted


State of Hawaii Public Utilities Commission. Docket No. 2009-0050. Application of Kauai Island Utility Cooperative for Approval of Rate Changes and Increases, Revised Rate Schedules and Rules,


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
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.
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.
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.

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)**

<table>
<thead>
<tr>
<th>Model</th>
<th>Residential</th>
<th>Commercial</th>
<th>Large Power</th>
</tr>
</thead>
<tbody>
<tr>
<td>IOU</td>
<td>41.32</td>
<td>42.66</td>
<td>41.12</td>
</tr>
<tr>
<td>CO-OP</td>
<td>40.31</td>
<td>41.61</td>
<td>41.80</td>
</tr>
<tr>
<td>SB (OUTSIDE)</td>
<td>41.82</td>
<td>43.17</td>
<td>43.17</td>
</tr>
<tr>
<td>SB (INSIDE)</td>
<td>41.82</td>
<td>43.17</td>
<td>43.17</td>
</tr>
</tbody>
</table>

**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 true 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.
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.

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)**

![Graph showing average rates for Molokai](image)

### 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)**

<table>
<thead>
<tr>
<th>Change of the Ownership Model</th>
<th>Honolulu County</th>
<th>Hawaii County</th>
<th>Maui County</th>
<th>Kauai County</th>
</tr>
</thead>
<tbody>
<tr>
<td>Move to a co-op model</td>
<td>↑ 5.3%</td>
<td>↑ 8.2%</td>
<td>↓ -1.8%</td>
<td></td>
</tr>
<tr>
<td>Move to a Single buyer within the utility model</td>
<td>↓ -0.7%</td>
<td>↑ 0.3%</td>
<td>↓ -1.3%</td>
<td>↑ 1.0%</td>
</tr>
<tr>
<td>Move to a Single buyer outside the utility model</td>
<td>↓ -0.8%</td>
<td>↑ 0.3%</td>
<td>↓ -1.3%</td>
<td>↑ 1.0%</td>
</tr>
<tr>
<td>Move to an IOU model</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Maui County - county-wide ownership model change</th>
<th>Maui</th>
<th>Lanai</th>
<th>Molokai</th>
</tr>
</thead>
<tbody>
<tr>
<td>Move to a co-op model</td>
<td>↓ -1.8%</td>
<td>↓ -1.4%</td>
<td>↓ -2.5%</td>
</tr>
<tr>
<td>Move to a Single buyer within the utility model</td>
<td>↓ -1.3%</td>
<td>↑ 0.8%</td>
<td>↑ 1.2%</td>
</tr>
<tr>
<td>Move to a Single buyer outside the utility model</td>
<td>↓ -1.3%</td>
<td>↑ 0.8%</td>
<td>↑ 1.2%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Maui County - ownership model change by island</th>
<th>Maui</th>
<th>Lanai</th>
<th>Molokai</th>
</tr>
</thead>
<tbody>
<tr>
<td>Move to a co-op model</td>
<td>↓ -1.8%</td>
<td>↓ -1.4%</td>
<td>↓ -2.5%</td>
</tr>
<tr>
<td>Move to a Single buyer within the utility model</td>
<td>↓ -1.3%</td>
<td>↑ 29.6%</td>
<td>↑ 29.1%</td>
</tr>
<tr>
<td>Move to a Single buyer outside the utility model</td>
<td>↓ -1.3%</td>
<td>↑ 31.2%</td>
<td>↑ 30.3%</td>
</tr>
</tbody>
</table>
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

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 criteria³ 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).
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:

• 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): 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

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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.

Moreover, the HECO Companies provide an optional Time-of-Use ("TOU") pilot rate program for Schedule R/ G/ J/ P rate classes. 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. 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)](attachment:image)

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. Figure 13 shows KIUC’s average rate for each rate class in 2016.

![Figure 13. KIUC: average price of electricity (2016 average cents/kWh)](attachment:image)

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.

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8 Participation is voluntary. Only HELCO and MECO (not HECO) have Time-of-Use rate schedule for Schedule P.


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.\textsuperscript{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.\textsuperscript{12} Three major steps are involved in the embedded cost of service study methodology, as shown in Figure 14, namely:\textsuperscript{13}

1. \textit{functionalization of costs and rate base items into the major operating functions of production, transmission, and distribution};

2. \textit{classification of the functionalized costs into the three cost components of energy-related costs, demand-related costs, and customer-related costs}; and,

3. \textit{allocation of the cost components to the different rate classes}.

Each step will be discussed in detail below.

---

\textbf{Figure 14. Key steps in the cost of service study methodology}

<table>
<thead>
<tr>
<th>STEP 1: Functionalization of the costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>STEP 2: Classification of the functionalized costs</td>
</tr>
<tr>
<td>STEP 3: Allocation of the cost components</td>
</tr>
</tbody>
</table>


\textsuperscript{12} Ibid.

\textsuperscript{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. For those costs associated with plant-in-service, most of the operation and maintenance expenses can be functionalized by account number analysis. 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. The HECO Companies categorize these general type costs by analyzing their characteristics or by using an appropriate functionalization base.

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.

<table>
<thead>
<tr>
<th>NARUC Account: HECO</th>
<th>Labor (Direct and On-cost)</th>
<th>% of Labor Total</th>
<th>Non-Labor (Direct and On-cost)</th>
<th>% of Non-Labor Total</th>
<th>Total = Labor + Non-Labor</th>
<th>% of Labor + Non-Labor Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production Operations</td>
<td>20,255,836</td>
<td>18.1%</td>
<td>17,843,502</td>
<td>18.1%</td>
<td>38,099,338</td>
<td>18.1%</td>
</tr>
<tr>
<td>Production Maintenance</td>
<td>16,026,407</td>
<td>14.3%</td>
<td>14,160,695</td>
<td>14.4%</td>
<td>30,187,102</td>
<td>14.3%</td>
</tr>
<tr>
<td>Transmission Operation</td>
<td>3,959,693</td>
<td>3.5%</td>
<td>3,516,725</td>
<td>3.6%</td>
<td>7,476,418</td>
<td>3.6%</td>
</tr>
<tr>
<td>Transmission Maintenance</td>
<td>2,889,938</td>
<td>2.6%</td>
<td>2,589,248</td>
<td>2.6%</td>
<td>5,479,186</td>
<td>2.6%</td>
</tr>
<tr>
<td>Distribution Operation</td>
<td>11,776,756</td>
<td>10.5%</td>
<td>10,353,455</td>
<td>10.5%</td>
<td>22,130,211</td>
<td>10.5%</td>
</tr>
<tr>
<td>Distribution Maintenance</td>
<td>6,489,207</td>
<td>5.8%</td>
<td>5,774,534</td>
<td>5.9%</td>
<td>12,263,741</td>
<td>5.8%</td>
</tr>
<tr>
<td>Customer Accounts</td>
<td>11,888,508</td>
<td>10.6%</td>
<td>10,060,958</td>
<td>10.2%</td>
<td>21,949,466</td>
<td>10.4%</td>
</tr>
<tr>
<td>Customer Services</td>
<td>5,485,670</td>
<td>4.9%</td>
<td>4,783,855</td>
<td>4.9%</td>
<td>10,269,525</td>
<td>4.9%</td>
</tr>
<tr>
<td>A&amp;G Operation</td>
<td>32,998,793</td>
<td>29.5%</td>
<td>29,078,235</td>
<td>29.6%</td>
<td>62,077,028</td>
<td>29.5%</td>
</tr>
<tr>
<td>A&amp;G Maintenance</td>
<td>238,575</td>
<td>0.2%</td>
<td>206,501</td>
<td>0.2%</td>
<td>445,076</td>
<td>0.2%</td>
</tr>
<tr>
<td><strong>Grand Total</strong></td>
<td><strong>112,009,383</strong></td>
<td><strong>100.0%</strong></td>
<td><strong>98,367,708</strong></td>
<td><strong>100.0%</strong></td>
<td><strong>210,377,091</strong></td>
<td><strong>100.0%</strong></td>
</tr>
</tbody>
</table>

16 Ibid, page 12.
<table>
<thead>
<tr>
<th>NARUC Account: HELCO</th>
<th>Labor (Direct and On-cost)</th>
<th>% of Labor Total</th>
<th>Non-Labor (Direct and On-cost)</th>
<th>% of Non-Labor Total</th>
<th>Total = Labor + Non-Labor</th>
<th>% of Labor + Non-Labor Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production</td>
<td>9,422,884</td>
<td>49.9%</td>
<td>12,224,556</td>
<td>21.5%</td>
<td>21,647,440</td>
<td>28.5%</td>
</tr>
<tr>
<td>Transmission</td>
<td>1,733,146</td>
<td>9.2%</td>
<td>3,456,033</td>
<td>6.1%</td>
<td>5,199,179</td>
<td>6.8%</td>
</tr>
<tr>
<td>Distribution</td>
<td>3,390,208</td>
<td>17.9%</td>
<td>10,299,678</td>
<td>18.0%</td>
<td>13,690,886</td>
<td>18.0%</td>
</tr>
<tr>
<td>Customer Accounts</td>
<td>49,098</td>
<td>0.3%</td>
<td>9,476,008</td>
<td>16.6%</td>
<td>9,525,106</td>
<td>12.6%</td>
</tr>
<tr>
<td>Customer Services</td>
<td>409,449</td>
<td>2.2%</td>
<td>444,143</td>
<td>0.8%</td>
<td>853,592</td>
<td>1.1%</td>
</tr>
<tr>
<td>A&amp;G</td>
<td>3,885,797</td>
<td>20.6%</td>
<td>21,091,376</td>
<td>37.0%</td>
<td>24,977,173</td>
<td>32.9%</td>
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<tr>
<td><strong>Grand Total</strong></td>
<td>18,890,582</td>
<td>100.0%</td>
<td>56,951,994</td>
<td>100.0%</td>
<td>75,842,576</td>
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<table>
<thead>
<tr>
<th>NARUC Account: MECO - Maui</th>
<th>Labor (Direct and On-cost)</th>
<th>% of Labor Total</th>
<th>Non-Labor (Direct and On-cost)</th>
<th>% of Non-Labor Total</th>
<th>Total = Labor + Non-Labor</th>
<th>% of Labor + Non-Labor Total</th>
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</thead>
<tbody>
<tr>
<td>Production Operations</td>
<td>7,012,645</td>
<td>37.4%</td>
<td>5,208,193</td>
<td>12.1%</td>
<td>12,220,838</td>
<td>19.7%</td>
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<tr>
<td>Production Maintenance</td>
<td>4,488,965</td>
<td>23.9%</td>
<td>7,940,103</td>
<td>18.4%</td>
<td>12,429,071</td>
<td>20.1%</td>
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<tr>
<td>Transmission Operation</td>
<td>597,579</td>
<td>3.2%</td>
<td>955,073</td>
<td>2.2%</td>
<td>1,552,652</td>
<td>2.5%</td>
</tr>
<tr>
<td>Transmission Maintenance</td>
<td>340,552</td>
<td>1.8%</td>
<td>1,546,484</td>
<td>3.6%</td>
<td>1,887,036</td>
<td>3.0%</td>
</tr>
<tr>
<td>Distribution Operation</td>
<td>1,874,262</td>
<td>10.0%</td>
<td>1,858,444</td>
<td>4.3%</td>
<td>3,732,706</td>
<td>6.0%</td>
</tr>
<tr>
<td>Distribution Maintenance</td>
<td>1,597,243</td>
<td>8.5%</td>
<td>2,494,307</td>
<td>5.8%</td>
<td>4,091,550</td>
<td>6.6%</td>
</tr>
<tr>
<td>Customer Accounts</td>
<td>205,470</td>
<td>1.1%</td>
<td>5,505,920</td>
<td>12.8%</td>
<td>5,709,390</td>
<td>9.2%</td>
</tr>
<tr>
<td>Customer Services</td>
<td>425,851</td>
<td>2.3%</td>
<td>3,308,833</td>
<td>7.7%</td>
<td>3,734,684</td>
<td>6.0%</td>
</tr>
<tr>
<td>A&amp;G Operation</td>
<td>2,211,479</td>
<td>11.8%</td>
<td>14,152,737</td>
<td>32.8%</td>
<td>16,364,216</td>
<td>26.4%</td>
</tr>
<tr>
<td>A&amp;G Maintenance</td>
<td>16,998</td>
<td>0.1%</td>
<td>380,696</td>
<td>0.4%</td>
<td>197,694</td>
<td>0.3%</td>
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<tr>
<td><strong>Grand Total</strong></td>
<td>18,767,047</td>
<td>100.0%</td>
<td>43,144,790</td>
<td>100.0%</td>
<td>61,909,837</td>
<td>100.0%</td>
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<table>
<thead>
<tr>
<th>NARUC Account: MECO - Lanai</th>
<th>Labor (Direct and On-cost)</th>
<th>% of Labor Total</th>
<th>Non-Labor (Direct and On-cost)</th>
<th>% of Non-Labor Total</th>
<th>Total = Labor + Non-Labor</th>
<th>% of Labor + Non-Labor Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production Operations</td>
<td>634,734</td>
<td>53.0%</td>
<td>364,164</td>
<td>25.2%</td>
<td>998,898</td>
<td>37.8%</td>
</tr>
<tr>
<td>Production Maintenance</td>
<td>353,810</td>
<td>29.5%</td>
<td>720,397</td>
<td>49.9%</td>
<td>1,074,207</td>
<td>40.7%</td>
</tr>
<tr>
<td>Transmission Operation</td>
<td>-</td>
<td>0.0%</td>
<td>-</td>
<td>0.0%</td>
<td>-</td>
<td>0.0%</td>
</tr>
<tr>
<td>Transmission Maintenance</td>
<td>-</td>
<td>0.0%</td>
<td>-</td>
<td>0.0%</td>
<td>-</td>
<td>0.0%</td>
</tr>
<tr>
<td>Distribution Operation</td>
<td>47,957</td>
<td>4.0%</td>
<td>39,389</td>
<td>2.7%</td>
<td>87,346</td>
<td>3.3%</td>
</tr>
<tr>
<td>Distribution Maintenance</td>
<td>61,967</td>
<td>5.2%</td>
<td>(51,820)</td>
<td>-2.2%</td>
<td>30,147</td>
<td>1.1%</td>
</tr>
<tr>
<td>Customer Accounts</td>
<td>91,989</td>
<td>7.7%</td>
<td>141,701</td>
<td>9.8%</td>
<td>233,690</td>
<td>8.8%</td>
</tr>
<tr>
<td>Customer Services</td>
<td>-</td>
<td>0.0%</td>
<td>271</td>
<td>0.0%</td>
<td>271</td>
<td>0.0%</td>
</tr>
<tr>
<td>A&amp;G Operation</td>
<td>7,656</td>
<td>0.6%</td>
<td>208,642</td>
<td>14.5%</td>
<td>216,298</td>
<td>8.2%</td>
</tr>
<tr>
<td>A&amp;G Maintenance</td>
<td>-</td>
<td>0.0%</td>
<td>-</td>
<td>0.0%</td>
<td>-</td>
<td>0.0%</td>
</tr>
<tr>
<td><strong>Grand Total</strong></td>
<td>1,198,113</td>
<td>100.0%</td>
<td>1,442,744</td>
<td>100.0%</td>
<td>2,640,857</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>NARUC Account: MECO - Molokai</th>
<th>Labor (Direct and On-cost)</th>
<th>% of Labor Total</th>
<th>Non-Labor (Direct and On-cost)</th>
<th>% of Non-Labor Total</th>
<th>Total = Labor + Non-Labor</th>
<th>% of Labor + Non-Labor Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production Operations</td>
<td>687,676</td>
<td>61.7%</td>
<td>455,431</td>
<td>16.7%</td>
<td>1,143,107</td>
<td>29.8%</td>
</tr>
<tr>
<td>Production Maintenance</td>
<td>190,935</td>
<td>17.1%</td>
<td>922,540</td>
<td>33.9%</td>
<td>1,113,475</td>
<td>29.0%</td>
</tr>
<tr>
<td>Transmission Operation</td>
<td>11,256</td>
<td>1.0%</td>
<td>25,823</td>
<td>0.9%</td>
<td>37,079</td>
<td>1.0%</td>
</tr>
<tr>
<td>Transmission Maintenance</td>
<td>-</td>
<td>0.0%</td>
<td>46,822</td>
<td>1.7%</td>
<td>46,822</td>
<td>1.2%</td>
</tr>
<tr>
<td>Distribution Operation</td>
<td>50,445</td>
<td>4.5%</td>
<td>50,381</td>
<td>1.8%</td>
<td>100,826</td>
<td>2.6%</td>
</tr>
<tr>
<td>Distribution Maintenance</td>
<td>137,739</td>
<td>12.4%</td>
<td>378,221</td>
<td>13.9%</td>
<td>515,960</td>
<td>13.4%</td>
</tr>
<tr>
<td>Customer Accounts</td>
<td>29,302</td>
<td>2.6%</td>
<td>354,791</td>
<td>13.0%</td>
<td>384,095</td>
<td>10.0%</td>
</tr>
<tr>
<td>Customer Services</td>
<td>-</td>
<td>0.0%</td>
<td>2,691</td>
<td>0.1%</td>
<td>2,691</td>
<td>0.1%</td>
</tr>
<tr>
<td>A&amp;G Operation</td>
<td>1,404</td>
<td>0.1%</td>
<td>451,841</td>
<td>16.6%</td>
<td>453,245</td>
<td>11.8%</td>
</tr>
<tr>
<td>A&amp;G Maintenance</td>
<td>5,326</td>
<td>0.5%</td>
<td>35,577</td>
<td>1.3%</td>
<td>40,903</td>
<td>1.1%</td>
</tr>
<tr>
<td><strong>Grand Total</strong></td>
<td>1,114,083</td>
<td>100.0%</td>
<td>2,724,118</td>
<td>100.0%</td>
<td>3,838,201</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

Note: A&G stands for “Administration and General”
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.\textsuperscript{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.\textsuperscript{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.\textsuperscript{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.

\begin{table}[h]
\centering
\begin{tabular}{|c|c|c|c|c|}
\hline
\textbf{HECO} & \textbf{Demand Costs} & \textbf{Energy Costs} & \textbf{Customer Costs} & \textbf{Total Costs} \\
\hline
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\% & 15.66\% \\
Schedule P & 26.38\% & 25.48\% & 1.13\% & 23.43\% \\
Schedule F & 0.71\% & 0.52\% & 0.13\% & 0.55\% \\
\hline
\textbf{HELCO} & \textbf{Demand Costs} & \textbf{Energy Costs} & \textbf{Customer Costs} & \textbf{Total Costs} \\
\hline
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\% \\
\hline
\end{tabular}
\caption{Ratios of costs allocated to demand, energy, and customer for HECO, HELCO, and MECO (based on Minimum System Method)}
\end{table}

\textsuperscript{18} Ibid, page 12.
\textsuperscript{19} Ibid, page 12.
\textsuperscript{20} Ibid, page 13 - 14.
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.

Note: These numbers are rounded so the total may not equal to 100.00%.

<table>
<thead>
<tr>
<th>HELCO</th>
<th>Schedule R</th>
<th>Schedule G</th>
<th>Schedule J</th>
<th>Schedule P</th>
<th>Schedule F</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Allocation Factors:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average-Excess Demand</td>
<td>35.889</td>
<td>8.709</td>
<td>31.052</td>
<td>23.932</td>
<td>0.417</td>
<td>100.000</td>
</tr>
<tr>
<td>Class Peak Demand</td>
<td>43.900</td>
<td>9.277</td>
<td>28.475</td>
<td>17.750</td>
<td>0.599</td>
<td>100.000</td>
</tr>
<tr>
<td>Composite NCD</td>
<td>55.482</td>
<td>9.923</td>
<td>26.249</td>
<td>7.901</td>
<td>0.445</td>
<td>100.000</td>
</tr>
<tr>
<td>Energy Allocation Factors:</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gross Input</td>
<td>35.245</td>
<td>8.664</td>
<td>31.26</td>
<td>24.429</td>
<td>0.402</td>
<td>100.000</td>
</tr>
<tr>
<td>Customer Allocation Factors:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Primary Lines</td>
<td>80.371</td>
<td>15.805</td>
<td>3.401</td>
<td>0.204</td>
<td>0.218</td>
<td>100.000</td>
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<tr>
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<td>14.118</td>
<td>2.420</td>
<td>0.141</td>
<td>0.225</td>
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<tr>
<td>Transformers</td>
<td>77.810</td>
<td>16.525</td>
<td>4.709</td>
<td>0.744</td>
<td>0.211</td>
<td>100.000</td>
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<tr>
<td>Services</td>
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<td>3.370</td>
<td>0.232</td>
<td>0.217</td>
<td>100.000</td>
</tr>
<tr>
<td>Meter</td>
<td>68.801</td>
<td>13.638</td>
<td>15.091</td>
<td>2.284</td>
<td>0.187</td>
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</tr>
<tr>
<td>Cust Acct Fct</td>
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<td>16.023</td>
<td>3.636</td>
<td>0.238</td>
<td>0.274</td>
<td>100.000</td>
</tr>
<tr>
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<td>64.150</td>
<td>14.680</td>
<td>11.000</td>
<td>10.160</td>
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<td>100.000</td>
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<tr>
<td>Cust Serv Fct</td>
<td>21.410</td>
<td>9.463</td>
<td>37.137</td>
<td>31.940</td>
<td>0.050</td>
<td>100.000</td>
</tr>
<tr>
<td>Avg Cust</td>
<td>84.456</td>
<td>13.286</td>
<td>1.922</td>
<td>0.107</td>
<td>0.229</td>
<td>100.000</td>
</tr>
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</table>

<table>
<thead>
<tr>
<th>MECO - Maui Division</th>
<th>Schedule R</th>
<th>Schedule G</th>
<th>Schedule J</th>
<th>Schedule P</th>
<th>Schedule F</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Allocation Factors:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average-Excess Demand</td>
<td>37.391</td>
<td>9.530</td>
<td>24.865</td>
<td>27.548</td>
<td>0.665</td>
<td>100.000</td>
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<tr>
<td>Class Peak Demand</td>
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<td>25.047</td>
<td>28.040</td>
<td>0.639</td>
<td>100.000</td>
</tr>
<tr>
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<td>25.272</td>
<td>15.302</td>
<td>0.572</td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gross Input</td>
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<td>7.564</td>
<td>26.234</td>
<td>33.575</td>
<td>0.395</td>
<td>100.000</td>
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<tr>
<td>Customer Allocation Factors:</td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Primary Lines</td>
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</tr>
<tr>
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<td>3.025</td>
<td>0.257</td>
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<td>1.922</td>
<td>0.107</td>
<td>0.229</td>
<td>100.000</td>
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<td>100.000</td>
</tr>
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<td>11.560</td>
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<td>100.000</td>
</tr>
<tr>
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<td>32.360</td>
<td>31.940</td>
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<td>100.000</td>
</tr>
<tr>
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<td>0.327</td>
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</table>

<table>
<thead>
<tr>
<th>MECO - Lanai Division</th>
<th>Schedule R</th>
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<th>Schedule J</th>
<th>Schedule P</th>
<th>Schedule F</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Allocation Factors:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average-Excess Demand</td>
<td>32.152</td>
<td>5.285</td>
<td>23.490</td>
<td>38.616</td>
<td>0.456</td>
<td>100.000</td>
</tr>
<tr>
<td>Class Peak Demand</td>
<td>32.688</td>
<td>5.301</td>
<td>23.324</td>
<td>38.216</td>
<td>0.471</td>
<td>100.000</td>
</tr>
<tr>
<td>Composite NCD</td>
<td>53.035</td>
<td>6.006</td>
<td>28.780</td>
<td>11.737</td>
<td>0.443</td>
<td>100.000</td>
</tr>
<tr>
<td>Energy Allocation Factors:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gross Input</td>
<td>26.965</td>
<td>5.133</td>
<td>25.097</td>
<td>42.492</td>
<td>0.313</td>
<td>100.000</td>
</tr>
<tr>
<td>Customer Allocation Factors:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Primary Lines</td>
<td>82.110</td>
<td>12.539</td>
<td>4.804</td>
<td>0.328</td>
<td>0.218</td>
<td>100.000</td>
</tr>
<tr>
<td>Secondary Lines</td>
<td>84.381</td>
<td>11.664</td>
<td>3.507</td>
<td>0.224</td>
<td>0.224</td>
<td>100.000</td>
</tr>
<tr>
<td>Transformers</td>
<td>81.645</td>
<td>12.791</td>
<td>5.347</td>
<td>0.000</td>
<td>0.217</td>
<td>100.000</td>
</tr>
<tr>
<td>Services</td>
<td>69.127</td>
<td>9.374</td>
<td>20.246</td>
<td>1.069</td>
<td>0.184</td>
<td>100.000</td>
</tr>
<tr>
<td>Meter</td>
<td>74.164</td>
<td>14.352</td>
<td>9.443</td>
<td>1.843</td>
<td>0.197</td>
<td>100.000</td>
</tr>
<tr>
<td>Cust Acct Fct</td>
<td>79.747</td>
<td>13.239</td>
<td>6.318</td>
<td>0.477</td>
<td>0.219</td>
<td>100.000</td>
</tr>
<tr>
<td>Bad Debt</td>
<td>99.810</td>
<td>0.180</td>
<td>0.010</td>
<td>0.000</td>
<td>0.000</td>
<td>100.000</td>
</tr>
<tr>
<td>Cust Serv Fct</td>
<td>21.410</td>
<td>14.235</td>
<td>32.365</td>
<td>31.940</td>
<td>0.050</td>
<td>100.000</td>
</tr>
<tr>
<td>Avg Cust</td>
<td>85.503</td>
<td>11.256</td>
<td>2.843</td>
<td>0.171</td>
<td>0.227</td>
<td>100.000</td>
</tr>
</tbody>
</table>
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 sales forecasts.

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21 Ibid, page 17.


23 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.”  

As a result, HECO Companies proposed an equal percentage increase in revenues at current effective rates for each rate class in its filings.

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.

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; 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. 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-related.
related, 45% energy-related, and 7% customer-related. 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)**

<table>
<thead>
<tr>
<th>Description</th>
<th>Demand</th>
<th>%</th>
<th>Energy</th>
<th>%</th>
<th>Customer</th>
<th>%</th>
<th>Total</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production</td>
<td>$35,268,510</td>
<td>36%</td>
<td>$61,774,224</td>
<td>64%</td>
<td>-</td>
<td>0%</td>
<td>$97,042,734</td>
<td>100%</td>
</tr>
<tr>
<td>Transmission</td>
<td>$9,875,574</td>
<td>100%</td>
<td>-</td>
<td>0%</td>
<td>-</td>
<td>0%</td>
<td>$9,875,574</td>
<td>100%</td>
</tr>
<tr>
<td>Distribution</td>
<td>$20,773,114</td>
<td>69%</td>
<td>-</td>
<td>0%</td>
<td>$9,396,373</td>
<td>31%</td>
<td>$30,169,487</td>
<td>100%</td>
</tr>
<tr>
<td>Total Cost of Service</td>
<td>$65,917,198</td>
<td>48%</td>
<td>$61,774,224</td>
<td>45%</td>
<td>$9,396,373</td>
<td>7%</td>
<td>$137,087,795</td>
<td>100%</td>
</tr>
</tbody>
</table>

Note: The Project Team found the 2010 cost of service functionalization and classification data as the most updated one that is publicly available.


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.”

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. 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. As a result, the revenue requirement of the test year 2010 allocated to each customer class is shown in Figure 20.
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. 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).

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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

1 Estimate forecast of energy sales for each utility and each customer class

2 Estimate forecast of revenue requirements for each customer class in each utility (county and islands) under each regulatory model
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

<table>
<thead>
<tr>
<th>Customer class</th>
<th>HECO</th>
<th>HELCO</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Electricity sales ratio</td>
<td>Electricity revenues ratio</td>
</tr>
<tr>
<td>Residential</td>
<td>23.7%</td>
<td>28.1%</td>
</tr>
<tr>
<td>Commercial</td>
<td>32.0%</td>
<td>33.0%</td>
</tr>
<tr>
<td>Large Power</td>
<td>43.7%</td>
<td>38.3%</td>
</tr>
<tr>
<td>Other</td>
<td>0.5%</td>
<td>0.6%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Customer class</th>
<th>MECO - Molokai Island</th>
<th>MECO - Lanai Island</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Electricity sales ratio</td>
<td>Electricity revenues ratio</td>
</tr>
<tr>
<td>Residential</td>
<td>32.9%</td>
<td>33.6%</td>
</tr>
<tr>
<td>Commercial</td>
<td>31.8%</td>
<td>35.2%</td>
</tr>
<tr>
<td>Large Power</td>
<td>34.8%</td>
<td>30.9%</td>
</tr>
<tr>
<td>Other</td>
<td>0.5%</td>
<td>0.4%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Customer class</th>
<th>MECO - Molokai Island</th>
<th>KIUC</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Electricity sales ratio</td>
<td>Electricity revenues ratio</td>
</tr>
<tr>
<td>Residential</td>
<td>35.5%</td>
<td>34.1%</td>
</tr>
<tr>
<td>Commercial</td>
<td>43.3%</td>
<td>45.5%</td>
</tr>
<tr>
<td>Large Power</td>
<td>19.2%</td>
<td>19.1%</td>
</tr>
<tr>
<td>Other</td>
<td>2.0%</td>
<td>1.3%</td>
</tr>
</tbody>
</table>

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 model 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).

<table>
<thead>
<tr>
<th>2017 cents/kWh</th>
<th>IOU</th>
<th>Co-op</th>
<th>SB (outside)</th>
<th>SB (inside)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>28.3</td>
<td>29.8</td>
<td>28.1</td>
<td>28.1</td>
</tr>
<tr>
<td>Commercial</td>
<td>24.7</td>
<td>26.0</td>
<td>24.5</td>
<td>24.5</td>
</tr>
<tr>
<td>Large power</td>
<td>21.0</td>
<td>22.1</td>
<td>20.8</td>
<td>20.8</td>
</tr>
<tr>
<td>Other</td>
<td>25.8</td>
<td>27.2</td>
<td>25.6</td>
<td></td>
</tr>
</tbody>
</table>

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.

<table>
<thead>
<tr>
<th>2017 dollars</th>
<th>IOU</th>
<th>Co-op</th>
<th>SB (outside)</th>
<th>SB (inside)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>$121</td>
<td>$127</td>
<td>$120</td>
<td>$120</td>
</tr>
<tr>
<td>Commercial</td>
<td>$1,188</td>
<td>$1,253</td>
<td>$1,180</td>
<td>$1,179</td>
</tr>
<tr>
<td>Large power</td>
<td>$102,588</td>
<td>$108,190</td>
<td>$101,880</td>
<td>$101,837</td>
</tr>
<tr>
<td>Other</td>
<td>$576</td>
<td>$608</td>
<td>$572</td>
<td>$572</td>
</tr>
</tbody>
</table>

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.\textsuperscript{36} Figure 25 illustrates

\textsuperscript{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**

<table>
<thead>
<tr>
<th>2017 cents/kWh</th>
<th>IOU</th>
<th>Co-op</th>
<th>SB (outside)</th>
<th>SB (inside)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>37.8</td>
<td>40.9</td>
<td>37.9</td>
<td>37.9</td>
</tr>
<tr>
<td>Commercial</td>
<td>35.4</td>
<td>38.3</td>
<td>35.5</td>
<td>35.5</td>
</tr>
<tr>
<td>Large power</td>
<td>29.1</td>
<td>31.5</td>
<td>29.2</td>
<td>29.2</td>
</tr>
<tr>
<td>Other</td>
<td>37.3</td>
<td>40.4</td>
<td>37.4</td>
<td>37.4</td>
</tr>
</tbody>
</table>

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**

<table>
<thead>
<tr>
<th>2017 dollars</th>
<th>IOU</th>
<th>Co-op</th>
<th>SB (outside)</th>
<th>SB (inside)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>$139</td>
<td>$151</td>
<td>$140</td>
<td>$140</td>
</tr>
<tr>
<td>Commercial</td>
<td>$791</td>
<td>$856</td>
<td>$793</td>
<td>$793</td>
</tr>
<tr>
<td>Large power</td>
<td>$56,406</td>
<td>$61,061</td>
<td>$56,563</td>
<td>$56,565</td>
</tr>
<tr>
<td>Other</td>
<td>$443</td>
<td>$480</td>
<td>$444</td>
<td>$444</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>2017 cents/kWh</th>
<th>IOU</th>
<th>Co-op</th>
<th>SB (outside)</th>
<th>SB (inside)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>MECO-wide transition</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Residential</td>
<td>31.3</td>
<td>30.7</td>
<td>30.8</td>
<td>30.5</td>
</tr>
<tr>
<td>Commercial</td>
<td>34.0</td>
<td>33.3</td>
<td>33.5</td>
<td>33.1</td>
</tr>
<tr>
<td>Large power</td>
<td>27.2</td>
<td>26.7</td>
<td>26.9</td>
<td>26.6</td>
</tr>
<tr>
<td>Other</td>
<td>21.7</td>
<td>21.3</td>
<td>21.4</td>
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<tr>
<td><strong>Island-specific transition</strong></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Residential</td>
<td>31.3</td>
<td>30.7</td>
<td>30.9</td>
<td>30.9</td>
</tr>
<tr>
<td>Commercial</td>
<td>34.0</td>
<td>33.3</td>
<td>33.5</td>
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<tr>
<td>Large power</td>
<td>27.2</td>
<td>26.7</td>
<td>26.9</td>
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<tr>
<td>Other</td>
<td>21.7</td>
<td>21.3</td>
<td>21.4</td>
<td>21.4</td>
</tr>
</tbody>
</table>
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.

<table>
<thead>
<tr>
<th>2017 dollars</th>
<th>IOU</th>
<th>Co-op</th>
<th>SB (outside)</th>
<th>SB (inside)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>$159</td>
<td>$156</td>
<td>$157</td>
<td>$155</td>
</tr>
<tr>
<td>Commercial</td>
<td>$1,017</td>
<td>$998</td>
<td>$1,003</td>
<td>$993</td>
</tr>
<tr>
<td>Large power</td>
<td>$59,564</td>
<td>$58,460</td>
<td>$58,753</td>
<td>$58,148</td>
</tr>
<tr>
<td>Other</td>
<td>$474</td>
<td>$465</td>
<td>$468</td>
<td>$463</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Island-specific transition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
</tr>
<tr>
<td>Commercial</td>
</tr>
<tr>
<td>Large power</td>
</tr>
<tr>
<td>Other</td>
</tr>
</tbody>
</table>

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.
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.

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).
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](image)

<table>
<thead>
<tr>
<th>2017 cents/kWh</th>
<th>IOU</th>
<th>Co-op</th>
<th>SB (outside)</th>
<th>SB (inside)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>MECO-wide transition</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Residential</td>
<td>41.3</td>
<td>40.3</td>
<td>41.8</td>
<td>41.8</td>
</tr>
<tr>
<td>Commercial</td>
<td>45.2</td>
<td>44.1</td>
<td>45.7</td>
<td>45.8</td>
</tr>
<tr>
<td>Large power</td>
<td>42.7</td>
<td>41.6</td>
<td>43.2</td>
<td>43.2</td>
</tr>
<tr>
<td>Other</td>
<td>29.0</td>
<td>28.3</td>
<td>29.3</td>
<td>29.4</td>
</tr>
<tr>
<td><strong>Island-specific transition</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Residential</td>
<td>41.3</td>
<td>40.3</td>
<td>53.3</td>
<td>53.8</td>
</tr>
<tr>
<td>Commercial</td>
<td>45.2</td>
<td>44.1</td>
<td>58.4</td>
<td>58.9</td>
</tr>
<tr>
<td>Large power</td>
<td>42.7</td>
<td>41.6</td>
<td>55.1</td>
<td>55.6</td>
</tr>
<tr>
<td>Other</td>
<td>29.0</td>
<td>28.3</td>
<td>37.4</td>
<td>37.8</td>
</tr>
</tbody>
</table>

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.
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).
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

<table>
<thead>
<tr>
<th>2017 cents/kWh</th>
<th>IOU</th>
<th>Co-op</th>
<th>SB (outside)</th>
<th>SB (inside)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>40.7</td>
<td>38.1</td>
<td>38.5</td>
<td>38.5</td>
</tr>
<tr>
<td>Commercial</td>
<td>40.2</td>
<td>37.7</td>
<td>38.0</td>
<td>38.0</td>
</tr>
<tr>
<td>Large power</td>
<td>35.8</td>
<td>33.5</td>
<td>33.9</td>
<td>33.9</td>
</tr>
<tr>
<td>Other</td>
<td>57.7</td>
<td>54.1</td>
<td>54.6</td>
<td>54.6</td>
</tr>
</tbody>
</table>
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 average monthly bill over forecast horizon in Kauai County for each ownership model**

<table>
<thead>
<tr>
<th>2017 dollars</th>
<th>IOU</th>
<th>Co-op</th>
<th>SB (outside)</th>
<th>SB (inside)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>$167</td>
<td>$156</td>
<td>$158</td>
<td>$158</td>
</tr>
<tr>
<td>Commercial</td>
<td>$703</td>
<td>$659</td>
<td>$665</td>
<td>$665</td>
</tr>
<tr>
<td>Large power</td>
<td>$33,765</td>
<td>$31,644</td>
<td>$31,957</td>
<td>$31,950</td>
</tr>
<tr>
<td>Other</td>
<td>$30</td>
<td>$28</td>
<td>$28</td>
<td>$28</td>
</tr>
</tbody>
</table>

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**
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


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

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
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<tbody>
<tr>
<td>CFC</td>
<td>Cooperative Finance Corporation</td>
</tr>
<tr>
<td>DBEDT</td>
<td>Hawaii Department of Business, Economic Development, and Tourism</td>
</tr>
<tr>
<td>DCF</td>
<td>Discounted Cash Flow</td>
</tr>
<tr>
<td>FFB</td>
<td>Federal Financing Bank</td>
</tr>
<tr>
<td>HECO</td>
<td>Hawaiian Electric Company</td>
</tr>
<tr>
<td>HEI</td>
<td>Hawaiian Electric Industries Inc.</td>
</tr>
<tr>
<td>HELCO</td>
<td>Hawaii Electric Light Company</td>
</tr>
<tr>
<td>IOU</td>
<td>Investor-Owned Utility</td>
</tr>
<tr>
<td>IPA</td>
<td>Illinois Power Agency</td>
</tr>
<tr>
<td>KIUC</td>
<td>Kauai Island Utility Cooperative</td>
</tr>
<tr>
<td>LEI</td>
<td>London Economics International LLC</td>
</tr>
<tr>
<td>MECO</td>
<td>Maui Electric Company</td>
</tr>
<tr>
<td>NCSC</td>
<td>National Cooperative Services Corporation</td>
</tr>
<tr>
<td>O&amp;M</td>
<td>Operations and Maintenance</td>
</tr>
<tr>
<td>OPA</td>
<td>Ontario Power Authority</td>
</tr>
<tr>
<td>PUC</td>
<td>Hawaii Public Utilities Commission</td>
</tr>
<tr>
<td>REDG</td>
<td>Rural Economic Development Grant</td>
</tr>
<tr>
<td>ROE</td>
<td>Return on Equity</td>
</tr>
<tr>
<td>RUS</td>
<td>Rural Utilities Service</td>
</tr>
<tr>
<td>SB</td>
<td>Single Buyer</td>
</tr>
<tr>
<td>TIER</td>
<td>Times Interest Earned Ratio</td>
</tr>
<tr>
<td>TNB</td>
<td>Tenaga Nasional Berhad</td>
</tr>
<tr>
<td>USDA</td>
<td>United States Department of Agriculture</td>
</tr>
<tr>
<td>WACC</td>
<td>Weighted Average Cost of Capital</td>
</tr>
</tbody>
</table>
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

<table>
<thead>
<tr>
<th>Achieve State energy goals</th>
<th>Maximize consumer cost savings</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs</td>
<td>Eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation</td>
</tr>
</tbody>
</table>

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 criteria³ 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).
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.\footnote{Hawaii Contract No. 65595, Scope of Services.}

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.
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 liabilities; 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


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. 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 on 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. 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. 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.

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

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9 Ibid.
$200 million from $175 million.\textsuperscript{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.\textsuperscript{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\textsuperscript{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


\textsuperscript{11} Ibid.

\textsuperscript{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. 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.

Figure 3 HECO Companies’ and comparable utilities’ capital structures, 2015-2018

<table>
<thead>
<tr>
<th>Utility name</th>
<th>Debt-to-equity ratio</th>
<th>Average cost of debt</th>
<th>Average ROE</th>
<th>Average WACC</th>
</tr>
</thead>
<tbody>
<tr>
<td>ALLETE, Inc.</td>
<td>85.8%</td>
<td>3.9%</td>
<td>9.3%</td>
<td>7.1%</td>
</tr>
<tr>
<td>Alliant Energy Corp. (Wisconsin Power and Light)</td>
<td>91.6%</td>
<td>5.2%</td>
<td>10.0%</td>
<td>7.9%</td>
</tr>
<tr>
<td>Avista Corp.</td>
<td>100.0%</td>
<td>5.7%</td>
<td>9.5%</td>
<td>7.6%</td>
</tr>
<tr>
<td>El Paso Electric Co.</td>
<td>106.8%</td>
<td>6.3%</td>
<td>9.7%</td>
<td>7.7%</td>
</tr>
<tr>
<td>Great Plains Energy, Inc. (Greater Missouri Operations Co.)</td>
<td>82.4%</td>
<td>4.2%</td>
<td>9.9%</td>
<td>7.7%</td>
</tr>
<tr>
<td>Northwestern Corp.</td>
<td>86.5%</td>
<td>3.5%</td>
<td>10.0%</td>
<td>7.2%</td>
</tr>
<tr>
<td>PNM Resources (Public Service Co. of NM)</td>
<td>101.6%</td>
<td>5.0%</td>
<td>9.6%</td>
<td>7.2%</td>
</tr>
<tr>
<td>Westar Energy Inc.</td>
<td>88.3%</td>
<td>5.0%</td>
<td>10.0%</td>
<td>8.0%</td>
</tr>
<tr>
<td>Wisconsin Energy Corp. (Wisconsin Public Service)</td>
<td>98.1%</td>
<td>6.3%</td>
<td>10.0%</td>
<td>8.2%</td>
</tr>
<tr>
<td>Hawaiian Electric Industries</td>
<td>71.9%</td>
<td>5.2%</td>
<td>9.5%</td>
<td>8.3%</td>
</tr>
</tbody>
</table>

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. HECO serves as the guarantor for its subsidiaries’ special purpose revenue bonds, their respective notes issued, and trust preferred securities. HECO would presumably withdraw this guarantee if MECO or HELCO changed ownership, which could impact their borrowing costs.

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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.

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.

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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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\(^{20}\) Ibid.


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


24 Ibid.

25 Ibid.

26 Ibid.

27 Ibid.


power generation or energy storage.\textsuperscript{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.\textsuperscript{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.\textsuperscript{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.\textsuperscript{34} Both short- and long-term loans are provided at fixed and variable interest rates for periods ranging from one month to 30 years.\textsuperscript{35}

In the case of KIUC, on November 1\textsuperscript{st}, 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.\textsuperscript{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\%.\textsuperscript{37,38}

\begin{itemize}
\item \textsuperscript{31} Ibid.
\item \textsuperscript{34} “Overview.” National Rural Utilities Cooperative Finance Corporation. Web. March 5, 2018. <https://www.nrufc.coop/content/cfc/about_cfc/overview.html>
\item \textsuperscript{35} Ibid.
\item \textsuperscript{38} KIUC. Kauai Island Utility Cooperative 2016 Annual Report.
\end{itemize}
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

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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. 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.

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. 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. Funds used from the IPA Facilities Fund are also subject to appropriation by the General Assembly.

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42 Ibid.
44 Ibid.
45 Ibid.
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.
8 Appendix B: List of works consulted


