Evaluation of Alternative Ownership Options for Electric Utility Assets on the Islands of Oahu and Hawaii

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EVALUATION OF ALTERNATIVE OWNERSHIP OPTIONS FOR ELECTRIC UTILITY ASSETS ON THE ISLANDS OF OAHU AND HAWAII

Prepared for:

Hawaii Natural Energy Institute

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Disclaimer

Filsinger Energy Partners' discussion of valuation techniques, cost estimates, acquisition costs, and budgets for a hypothetical new utility is intended to provide a high level approximation only, and does not constitute an official appraisal opinion nor an attestation of fair market value. Nothing in this report is intended to provide a legal opinion. All numbers are subject to change as additional diligence is conducted and/or market conditions change.

This report does not consider alternative utility grid system management options, such an independent system operator or independent distribution system operator model. Further, this report does not attempt to estimate customer rate impacts that might result from changing from investor ownership to cooperative or public ownership of the utilities.

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LIST OF ACRONYMS AND TERMS

APPA – American Public Power Association
CEO – Chief Executive Officer
CFC – National Rural Utilities Cooperative Finance Corporation
EBITDA – Earnings before interest, taxes, depreciation and amortization
EPE – El Paso Electric
FEP – Filsinger Energy Partners
FERC – Federal Energy Regulatory Commission
GO bond – General obligation bond
GWh – Gigawatt-hour
HECO – Hawaiian Electric Company, Inc.
HEI – Hawaiian Electric Industries, Inc.
HELCO – Hawaii Electric Light Company, Inc.
HNEI – Hawaii Natural Energy Institute
HPUC – Hawaii Public Utilities Commission
HRS – Hawaii Revised Statutes
JPUD – Jefferson County Public Utility District
KIUC – Kauai Island Utility Cooperative
kV – Kilovolt
kWh – Kilowatt-hour
MW – Megawatt
O&M – Operations and Maintenance
PILOT – Payment in lieu of tax
PNM – Public Service Company of New Mexico
PSCo – Public Service Company of Colorado
PUC – Public Utilities Commission
RCUH – Research Corporation of the University of Hawaii
REIT – Real estate investment trust
RPS – Renewable portfolio standards
RUS – U.S. Department of Agriculture's Rural Utilities Service
SAIDI – System Average Interruption Duration Index
SAIFI – System Average Interruption Frequency Index
SEC – U.S. Securities and Exchange Commission
SMUD – Sacramento Municipal Utility District
SPRB – Special purpose revenue bond
Tri-State – Tri-State Generation and Transmission Association, Inc.
USDA – U.S. Department of Agriculture
USPAP – Uniform Standards of Professional Appraisal Practice

1 INTRODUCTION

In February 2016, the Hawaii Natural Energy Institute ("HNEI"), though the Research Corporation of the University of Hawaii ("RCUH"), contracted Filsinger Energy Partners ("FEP") to provide consulting services and prepare a report for the purpose of reviewing the feasibility of alternative utility ownership options and to provide a plan that would provide guidance if it is decided to pursue the concept of a cooperative or publicly-owned utility on the islands of Oahu and/or Hawaii. Over the ensuing month and a half, FEP conducted analyses of potential ownership options, financing, contracts and legislation to prepare a plan forward for policymakers and interested stakeholders to consider when deciding whether or not to pursue a new ownership structure. This report details FEP's findings.

1.1 Overview of Hawaii's Electric Power System

The electric power system for the State of Hawaii currently serves a state population of over 1.4 million people[1] and generates over 10.2 billion kilowatt-hours ("kWh") annually.[2] The system is characterized by a series of independent, and currently unconnected, grids on each of the populated islands. As opposed to the mainland United States, where coal and natural gas-fired generators provide the majority of power production, the Hawaii power system predominately relies upon petroleum, coal and renewable energy sources. A comparison by fuel type of Hawaii's electric power generation (excluding customer-sited distributed generation) to the United States average is shown in Figure 1-1.

[1] "Quick Facts." U.S. Census Bureau. March 17, 2016. <http://www.census.gov/quickfacts/table/PST045215/15>

Estimate as of July 1, 2015.

[2] "Net Generation by State by Type of Producer of Energy Source (EIA-906, EIA-920, and EIA-923)." U.S. Energy Information Administration. March 17, 2016. <https://www.eia.gov/electricity/data/state/>

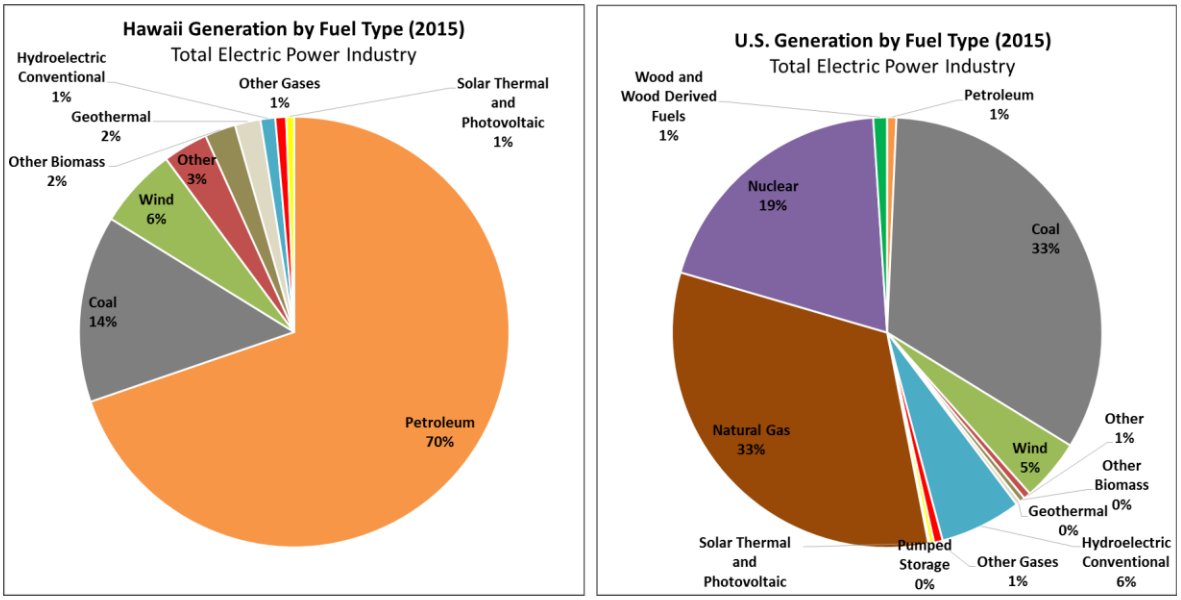

Figure 1-1: Hawaii vs. U.S. Generation by Fuel Type (2015)[3]

As can be seen in Figure 1-2, petroleum-fueled generation has dominated Hawaii's generation profile for at least the past 25 years, while the growth in overall generation has remained fairly flat.

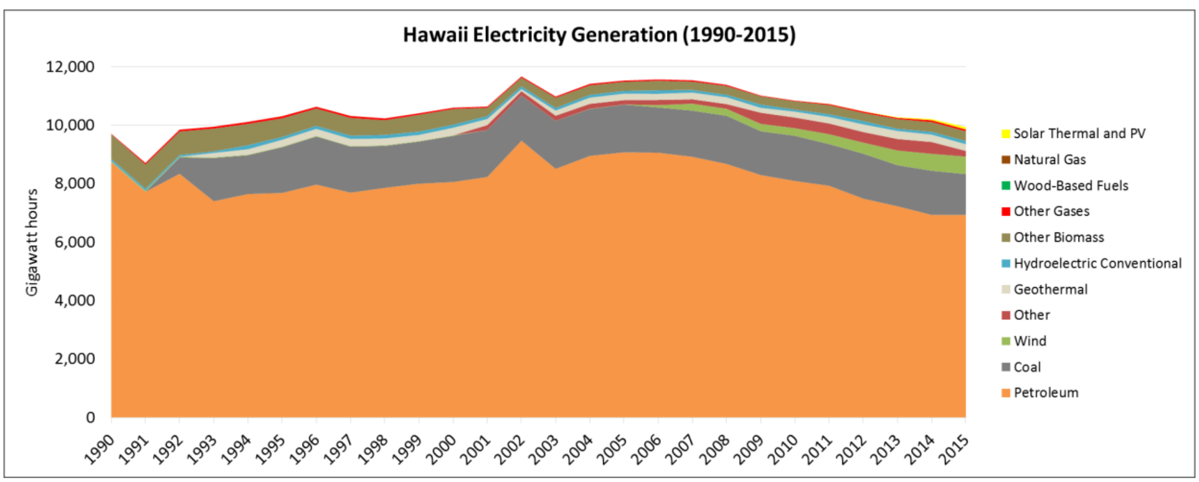

Figure 1-2: Hawaii Electricity Generation (1990-2015)[4]

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[3] Preliminary 2015 data from: "Monthly Generation Data by State, Producer Sector and Energy Source; Months through December 2015." U.S. Energy Information Administration. April 19, 2016. <http://www.eia.gov/electricity/data/state/generation_monthly.xlsx>

[4] "Net Generation by State by Type of Producer of Energy Source (EIA-906, EIA-920, and EIA-923)." U.S. Energy Information Administration. March 17, 2016. <https://www.eia.gov/electricity/data/state/>

As a direct consequence of Hawaii's heavy reliance on imported fossil fuels, as well as the added redundancies required to maintain the reliability of its island power grids, over the past 15 years Hawaii residents have paid residential electric rates that have at times averaged over 200% higher than their mainland peers.[5]

Despite its historically-high dependence on petroleum-fired power generation, Hawaii enjoys a plethora of renewable natural resources, including wind, solar, water, biomass, geothermal, and ocean energy. Hawaii's renewable portfolio standards ("RPS") law requires that 100% of the state's electric utility sales be represented by renewable energy sources by 2045.[6] Interim targets are set at 30% by 2020, 40% by 2030, and 70% by 2040. As of 2015, over 21% of utility electricity sales on Hawaii and Oahu were sourced from renewable resources, while the HEI companies' customer-sited generation increased nearly 25% year-over-year.[7] On Kauai, over 22% of generation came from renewables.[8]

In recent years, the incumbent utilities and independent power producers, as well as many individual retail electric customers, have been tapping the state's great potential to generate "green" energy. For example, solar photovoltaic installations have grown rapidly over the past several years (see Figure 1-3 below) to give Hawaii the distinction of being the state with the highest solar capacity per capita (312 watts) by the end of 2014.[9]

Preliminary 2015 data from: "Monthly Generation Data by State, Producer Sector and Energy Source; Months through December 2015." U.S. Energy Information Administration. April 19, 2016. <http://www.eia.gov/electricity/data/state/generation_monthly.xlsx>

[5] "Average Price by State by Provider (EIA-861)." U.S. Energy Information Administration. March 17, 2016.

[6] HRS § 269-91, 92.

[7] "2015 Renewable Portfolio Standard Status Report." Hawaiian Electric Industries, Inc. February 26, 2016. <http://puc.hawaii.gov/wp-content/uploads/2013/07/RPS-HECO-2015.pdf>

[8] "Annual Fuel Mix Disclosure." KIUC. March 21, 2016. <http://puc.hawaii.gov/wp-content/uploads/2013/07/Fuel-Mix-KIUC-2011-2015.pdf>

[9] "State of Hawaii Energy Resources Coordinator's Annual Report 2015." Hawaii State Energy Office. October 10, 2015. p.24 <http://energy.hawaii.gov/wp-content/uploads/2014/12/DBEDT_2015ERC-Report_Nov2015.pdf>

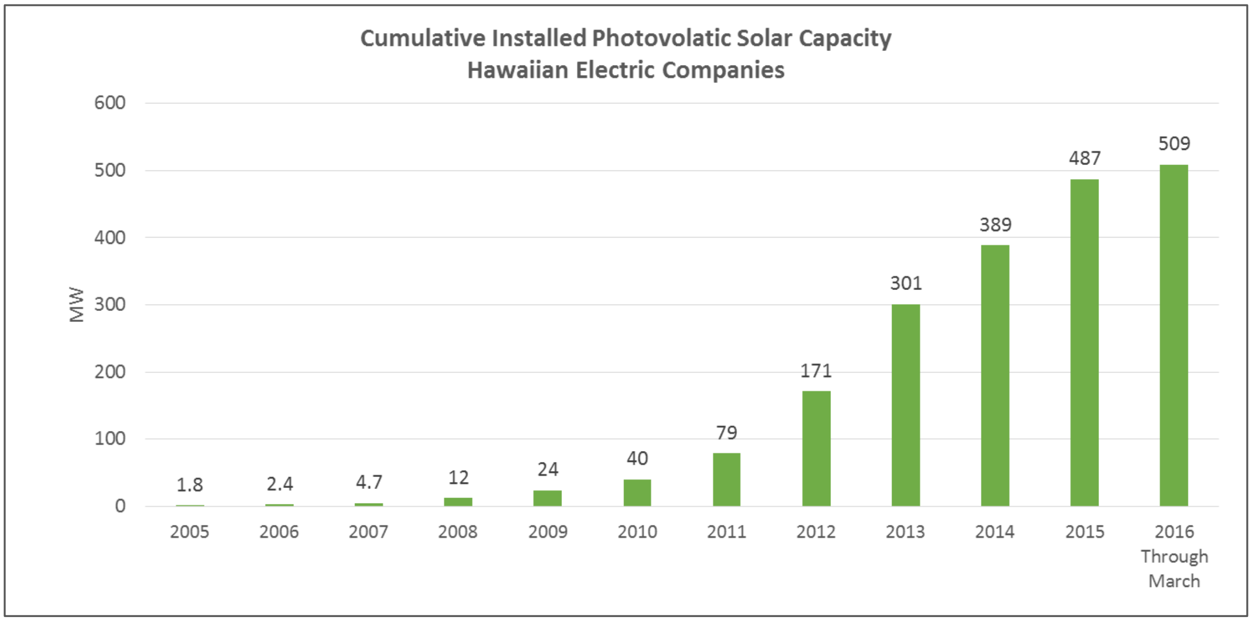

Figure 1-3: Cumulative Installed Photovoltaic Solar Capacity, Hawaiian Electric Companies[10]

No matter the structure of utility ownership in Hawaii, achieving the 100% RPS target, and the costs of doing so, are critical factors to many stakeholders across the state. In electric power systems throughout the country, the consideration of renewable energy procurement is largely driven by economics and public policy decisions, including the availability and production costs for renewable and non-renewable generation resources, environmental air quality regulations, and RPS regulations. Generally, renewable resources will be most competitive in regions that contain abundant renewable resources combined with high costs for fossil fuels. Hawaii meets both of these criteria.

While Hawaii's electric system faces certain challenges that many of its mainland contemporaries do not (including: the integration of increasingly high penetrations of variable renewable energy resources, a lack of backup from neighboring systems and very high costs for imported fuels), the state's unique isolated geography and existing utility ownership structure may make it an attractive candidate for the acquisition of an entire island electric grid, whether by municipal, cooperative, or investor ownership.

[10] "Cumulative Installed PV – As of Mar. 31, 2016." Hawaiian Electric Company, Inc. March 31, 2016. <https://www.hawaiianelectric.com/Documents/clean_energy_hawaii/going_solar/pv_summary_1Q_2016.pdf>

Currently, Hawaiian Electric Industries, Inc. (“HEI”), through its subsidiaries Hawaiian Electric Company, Inc. (“HECO”) and Hawaii Electric Light Company, Inc. (“HELCO”), own and operate vertically-integrated utilities on Oahu and Hawaii Island, respectively. While several third-party power producers sell wholesale power to these two investor-owned utilities, HECO and HELCO sell power to their entire islands. Consequently, acquisition of HECO and/or HELCO assets in their entirety would avoid many of the complicated engineering and billing conundrums that have faced other parties attempting to carve out a new grid from within a larger, interconnected network.

Hawaii’s physical location in the Pacific Ocean precludes its electric system from being connected to other states. Consequently, regulation by the Federal Energy Regulatory Commission (“FERC”) is more limited than in most other states, because regulatory authority is largely based on the “interstate commerce” of interconnected electric grids. Both of these factors may contribute to fewer technical and regulatory hurdles to pursuing alternative ownership structures than similar efforts have faced in other states.

The island of Kauai has already pursued a cooperatively-owned alternative to its former investor-owned utility, and its experiences since the turn of the millennium can provide many insights into the potential challenges and opportunities awaiting Oahu and Hawaii Island, should alternative ownership of the HECO and/or HELCO systems be pursued. FEP has reviewed the experiences of Kauai, as well as the municipalization attempt of the City of Boulder, Colorado, and these “case studies” are presented in this report.

1.2 Report Structure

FEP has structured this report and its analyses to serve several purposes, including to:

- Provide an overview of investor, public, and cooperative ownership models for electric utilities;
- Discuss the potential benefits and challenges associated with acquiring, financing, governing, and operating electric utilities under different ownership models;
- Highlight the experiences of other public power and cooperative utilities in order to learn from their achievements as well as their mistakes;

- Present a high level summary of recommended steps and analyses associated with forming an electric utility and acquiring assets from an incumbent service provider;
- Estimate very preliminary timing and cost ranges for these steps and analyses; and
- Briefly explain a few of the operational and staffing requirements to operate an electric utility.

These discussion points are organized as follows:

- Section 2 of the report presents the various ownership options, compares and contrasts their benefits as well as drawbacks, and includes several case studies of acquisition attempts by other municipal and cooperative utilities.
- Section 3 provides an introduction to many of the financing options and considerations that a new utility might face. It also introduces several important valuation concepts.
- Section 4 explains many of recommended analyses and next steps that might be taken, as well as their estimated costs and timelines given optimistic conditions. This section also presents an overview of a potential organizational structure for a new utility.
- Section 5 discusses several critical policy considerations and regulatory proceedings, which should be discussed with legal counsel, should an alternative ownership structure be pursued.

While there exist many attributes of the Hawaii electric system that may help facilitate the transition to an alternative ownership structure, the formation from scratch of a new electric utility is necessarily a non-trivial task, one which has often been fraught with legal, technical, and economic challenges. The acquisition and financing of electric infrastructure assets is merely one phase of a long process, which includes ongoing challenges, such as fuel contracting, operations and maintenance ("O&M"), and customer billing. Very few attempts by municipalities and public entities to condemn and acquire utility assets have been successful. Additionally, transactions of utility assets by cooperatives are essentially limited to friendly acquisitions, because condemnation via eminent domain is typically not an option.

Whether Hawaii chooses to maintain its existing investor ownership model or decides to embark on the challenging journey of forming a cooperative or municipal utility is ultimately a choice of the citizens and their elected policymakers. It is FEP's hope that this report can provide some guidance and insights into the process.

1.3 Scope of Analysis

For the purposes of this report, FEP considered alternative ownership options for the electric utility assets currently owned and operated by HECO and HELCO on the islands of Oahu and Hawaii, respectively. FEP did not consider any non-utility assets owned by HEI or its subsidiaries, nor did FEP consider Maui Electric's utility assets, Kauai Island Utility Cooperative ("KIUC") assets, or any third-party electric power facilities not owned by HEI companies.

Generally, FEP examined the systems of each island as the aggregate of their generation, transmission, and distribution infrastructure. While this report discusses the pros and cons of owning and operating a vertically-integrated utility versus a transmission and/or distribution-only entity, FEP did not conduct a detailed analysis of individual assets.

2 Overview of Potential Ownership Options

Across the United States, there are three broad categories of electric utility ownership: investor-owned, publicly-owned, and cooperatively-owned. This section describes various attributes of each ownership paradigm, highlighting both positives and negatives, with respect to the degree of local control, financing and operational costs, and performance and reliability, and renewable energy integration.

Throughout this chapter, FEP highlights the experiences of several utility systems through the use of case studies. In particular, FEP has chosen to focus on the acquisition and operations of utility assets managed by the Kauai Island Utility Cooperative and the municipalization attempt of the City of Boulder, Colorado. FEP chose to analyze KIUC for both its geographic and situational relevance (i.e. a Hawaii island that formed a new cooperative utility and acquired investor-owned assets), as well as the fact that it was one of the more recent cooperative utilities to be formed in the United States. FEP selected Boulder for use in a case study because the city's long-running municipalization attempt is both current and illustrative of many of the legal, economic, and technical challenges that could face a potential attempt to form a municipal or cooperative utility by the islands of Oahu and/or Hawaii. Finally, FEP briefly discusses the experiences of a few other cooperative and municipal utilities across the country.

2.1 Investor Ownership

Investor-owned power companies (either utilities or independent power producers) raise debt and equity financing through both public and private capital markets. Many of these companies are large C-corporations that raise debt capital through bank loans or issue bonds to investors and have publicly-traded equity, which is traded on exchanges such as the New York Stock Exchange or NASDAQ. Other investor-owned power companies are held by private equity firms and access both the public and private capital markets to finance operations. Management of investor-owned companies is ultimately accountable to shareholders and is typically overseen by a Board of Directors. The owners of an investor-owned power company are not necessarily the electric customers which it serves. As such, the degree of local control for investor ownership is usually less than that of a municipal or cooperative utility.

Publicly traded, investor-owned companies are subject to oversight by the U.S. Securities and Exchange Commission ("SEC"), which requires heightened reporting and financial disclosure, including both annual and periodic filings such as Forms 10-K and 10-Q for financial reporting, Form 8-K for disclosure of material company information, and annual proxy statements disclosing executive and Board compensation and other matters subject to shareholder approval. Regulated utilities are held to additional reporting requirements, including the submission of annual Form 1 documents to the FERC.

Interest paid on debt issued by investor-owned companies is typically taxable to the investor, and these companies are often ineligible for certain government and cooperative financing options. As such, the cost of borrowing is often higher than costs at municipal or cooperative utilities. These costs may also be impacted by credit ratings from third-party agencies, such as Moody's, Standard & Poor's, and Fitch. Because investor-owned company management is accountable to equity owners, the profit motive and the maximization of shareholder value are primary objectives. In the case of regulated investor-owned utilities, these goals are pursued while the additional mandates of reliable service and cost-efficient power procurement must also be met. These regulatory requirements, along with statutory mandates, serve to protect ratepayers (who may not necessarily be the direct owners of their electric power companies) and to align utility behavior with the public interest. Even with mandates and regulatory guidance, pursuing alternative corporate objectives (such as increasing renewable energy production or maximizing employment) without clear-cut economic benefits to shareholders can often be difficult for an investor-owned company.

Despite these limitations, investor-owned companies generate nearly 79%[11] of the electricity produced in America because this ownership structure presents one of the most effective means for raising large amounts of capital.

2.2 Public Ownership

Public utilities are owned by taxpayers and function as government agencies. Public utility ownership takes several forms. At one level, the federal government administers several federal power agencies that own (primarily hydroelectric) power plants and sell electricity directly into the wholesale markets and/or to large consumers. Examples of these entities include the Tennessee Valley Authority, Bonneville Power Administration, and the Bureau of Reclamation. Regional public power districts and municipally-owned utilities operate generation, transmission, and/or distribution facilities, serving customers in almost every state.[12] Nebraska's entire electric system is operated by a consortium of publicly-owned entities. In 2013, over 2,000 publicly owned utilities and nine federal power agencies served approximately 14.5% of electric customers and produced 16.4% of electricity generated in the United States.[13] For the purposes of this report, FEP refers to all forms of public electric utility ownership as "municipal."

Interest paid on municipal debt has the advantage to investors of being exempt from federal taxes and most state taxes. Thus, an economically-rational investor in a 30% marginal income tax bracket would be ambivalent between investing in a private bond that yields 5% interest and a tax-exempt public bond that yields 3.5% interest.[14] Because of their ability to issue tax-exempt financing, public utilities can typically borrow money for lower rates than can investor-owned power companies. However, one caveat of this distinct advantage is that public utilities cannot

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[11] "2015-2016 Public Power Annual Directory & Statistical Report." American Public Power Association. Includes "investor-owned utilities" and "non-utility generators."

[12] The exception is Hawaii.

[13] "2015-2016 Public Power Annual Directory & Statistical Report." American Public Power Association.

[14] After tax interest income for taxable bond is: 5%*(1-30%) = 3.5%; after-tax interest income for a tax-exempt bond is 3.5%*(1-0%) = 3.5%.

issue tax-exempt debt to acquire privately-held electric facilities.[15] As such, their lower borrowing costs only help in the maintenance of existing assets or the construction of new assets. To acquire HECO and HELCO's investor-owned assets, a theoretical Hawaii municipal utility would most likely have to issue taxable debt. As with investor-owned companies, municipal borrowing costs are also influenced by third-party credit ratings.

Unlike investor-owned companies, municipal utilities often pay little or no income, property, and sales taxes. These avoided taxes are frequently offset by a payment in lieu of tax ("PILOT") to the city or county. The amount of PILOT can be set locally by the municipality. The American Public Power Association ("APPA"), an industry group, reported that over 80% of surveyed public power companies reported paying a PILOT in 2012.[16] In APPA's study, the median public power distribution utility contributed 5.5% of its electric operating revenues in taxes and other payments to state and local governments, compared to a median payment of 4.2% for investor-owned distribution utilities. For APPA's sample of utilities with more than $100 million in annual operating revenues, these numbers were 6.4% and 4.3%, respectively.

In many states, municipal utilities are self-regulated and do not fall under the jurisdiction of state public utilities commissions ("PUC"s).[17] Self-regulation allows city and county administrators to set rates, develop resource plans, enter into power contracts, and perform other business functions without first seeking the sometimes lengthy and contentious approval process of external regulatory bodies. This has both pros and cons in terms of costs, local control, and consumer protections. Fewer legal and personnel resources may be needed to navigate the regulatory approval process, potentially equating to cost savings. However, the lack of independent oversight from PUCs has the potential to result in more capricious and politically-driven actions, which might hurt ratepayers in the long-run. Nevertheless, consumers of

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[15] See "Rostenkowski Rule" in "Tax Issues for Public Power." American Public Power Association. February 2012. <http://www.publicpower.org/files/PDFs/TaxIssuesforPublicPowerFeb2012IB.pdf>

[16] "2015-2016 Public Power Annual Directory & Statistical Report." American Public Power Association.

[17] "Utility Regulation and Policy." American Council for Energy-Efficient Economy. March 18, 2016. <http://aceee.org/topics/utility-regulation-and-policy>

municipal power systems maintain a strong degree of local control, regardless of whether there is PUC regulatory authority, due to the simple fact that they ultimately elect the officials that oversee and manage their electric systems. Additionally, customer grievances can be remedied by judicial action. Public input should be a critical component of any well-designed public power system.

There exist several common forms of public utility governance structures. APPA’s 2010 Governance Survey[18] found that 59% of its 658 surveyed utilities were governed directly by a city council, while the remaining 41% were governed by independent utility boards. City councils oversaw 72% of utilities serving less than 5,000 customers, while independent utility boards governed approximately two-thirds of utilities serving over 20,000 customers. The majority of independent utility boards were appointed or approved by city councils and/or mayors. Nearly half of independent utility boards served for terms of five or more years.

The Sacramento Municipal Utility District (“SMUD”), in central California, provides an example of a public power utility that is governed by an independent utility board. SMUD management is accountable to a seven-member board of directors, representing different geographic regions within the utility’s service territory.[19] These directors are elected by customers and serve four-year terms. By contrast, Austin Energy, a large municipal utility in Texas, is overseen by the Austin City Council. The Austin City Manager selects the utility’s General Manager, who hires the rest of the executive leadership team.[20]

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[18] “2010 Governance Survey.” American Public Power Association. August 2010. <http://www.publicpower.org/files/PDFs/2010GovernanceSurvey.pdf>

[19] “Our Board of Directors.” Sacramento Municipal Utility District. 2016. <https://www.smud.org/en/about-smud/company-information/board-of-directors/>

[20] “Company Profile: Executive Leadership Team.” Austin Energy. 2016. <http://austinenergy.com/wps/portal/ae/about/company-profile/executive-leadership-team/>

2.3 Cooperative Ownership

Cooperative power companies are "democratically controlled, not-for-profit electric utilities owned by the consumers they serve."[21] Federal rules require that every consumer-member have the right to vote to select cooperative board-members and that cooperatives must generally return to consumer-members any revenues that exceed their operating costs.[22] Election of officers must take place on a "one-member, one vote basis."[23] According to the National Rural Utilities Cooperative Finance Corporation, an industry financing cooperative, there are 838 electric distribution cooperatives and 66 generation and transmission cooperatives that serve nearly 80% of all U.S. counties across 47 states.[24] In 2013, these cooperative utilities provided service to 12.8% of electric customers across the country.[25] The electric power system on the island of Kauai is currently managed by a cooperatively-owned power company, KIUC, which is discussed more in Section 2.7.

Due to their democratic elective processes, as well as the fact that they are directly owned by the customers they serve, cooperative utilities usually exhibit high degrees of local control. Because they are ultimately accountable to these member-owners, and not to investors, cooperative utilities also have greater flexibility to set strategic objectives that may differ from purely profit-driven goals. However, in some states (including Hawaii), cooperative utilities are regulated by PUCs.

As with publicly-owned power companies, cooperatives are exempt from federal income taxes. This exemption holds true as long as "on an annual basis, at least 85 percent of their income comes directly from their member-owners for the sole purpose of meeting losses and expenses

[21] "Our Member-Owners." National Rural Utilities Cooperative Finance Corporation. March 10, 2016. <https://www.nrucfc.coop/content/cfc/about_cfc/our-members.html>

[22] "What is An Electric Cooperative?" The National Rural Electric Cooperative Association. March 10, 2016. <http://www.nreca.coop/about-electric-cooperatives/>

[23] Internal Revenue Manual § 7.25.12.5.

[24] "Our Member-Owners." National Rural Utilities Cooperative Finance Corporation. March 10, 2016. <https://www.nrucfc.coop/content/cfc/about_cfc/our-members.html>

[25] "2015-2016 Public Power Annual Directory & Statistical Report." American Public Power Association.

of providing [electric] service."[26] Depending on jurisdiction, cooperatives may still be subjected to state income taxes, local taxes or PILOTs, and/or franchise fees.

Several attractive financing options are available to cooperative utilities. These include loans and loan guarantees from the U.S. Department of Agriculture, as well as loans from the National Rural Utilities Cooperative Finance Corporation. Both of these options are further discussed in Section 3 of this report.

2.4 Reliability Considerations

Due to the uniqueness of each utility system and its operations, it is impossible to make generalizations about which type of ownership structure will result in the highest level of system reliability (and the lowest number and frequency of outages). Despite this limitation, FEP reviewed several reports about common utility reliability metrics. Its findings are explained below.

Two of the most commonly-reported metrics of utility reliability are the System Average Interruption Frequency Index ("SAIFI") and the System Average Interruption Duration Index ("SAIDI"). These indices respectively measure the average number of electric distribution system interruptions per year per customer and the average duration of combined interruptions, in minutes per customer-year.[27] Many investor-owned utilities are required to report these metrics annually to state regulatory bodies, while many public utilities voluntarily report these metrics to APPA.

A 2008 report, sponsored by the U.S. Department of Energy, summarized reliability data from 71 investor-owned utilities reporting SAIDI and SAIFI metrics with and without the inclusion of major events. The study found median SAIFI ratings of 1.2 outage events per year when major events were excluded, and 1.6 events with major events included. Likewise, it found median SAIDI

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[26] "Tax-Exempt Status." The National Rural Electric Cooperative Association. March 10, 2016. <http://www.nreca.coop/about-electric-cooperatives/tax-exempt-status/>

[27] For guidelines on measuring and calculating SAIFI and SAIDI metrics, see the Institute of Electrical and Electronics Engineers (IEEE) Standard 1366-2012.

ratings of 130 and 213 minutes per customer-year, when major events were respectively excluded and included.[28]

APPA's 2013 "Distribution System Reliability & Operations Survey"[29] reported reliability statistics from 180 survey respondents, representing approximately 9 percent of public power utilities in the United States. Reported statistics did not differentiate between inclusion and exclusion of major events; however APPA noted that only 58 respondents reported including major events in their numbers. APPA found an average SAIFI of 1.11 outage events and an average SAIDI of 58 minutes in 2012.[30] It is unclear whether any sampling, methodological, or operational differences between investor-owned and public utilities accounted for the variation in SAIDI ratings between the U.S. Department of Energy and APPA reports.

HEI also reports reliability metrics for each of its investor-owned utilities in Hawaii. Between 2005 and 2015, HECO reported SAIFI values between 1.13 and 2.12, whereas HELCO reported SAIFI values between 2.12 and 3.40.[31] During that same timeframe, SAIDI values for HECO and HELCO ranged from 90 to 211 minutes, and 114 to 207 minutes, respectively.

It is important to reiterate that the reliability numbers from these studies have been presented for illustrative – and not comparative – purposes. SAIFI and SAIDI indices are also impacted by the presence of an island environment, and ratings in Hawaii should really be compared to those of other island systems, not interconnected mainland utilities. Because each system is different, and because utilities may measure and report their outage data in different manners, FEP draws no conclusions from these findings about the relative reliability implications of different

[28] Eto, Joseph H. and Kristina Hamachi LaCommare. "Tracking the Reliability of the U.S. Electric Power System: An Assessment of Publicly Available Information Reported to State Public Utility Commissions." Ernest Orlando Lawrence Berkeley National Laboratory. October 2008.

[29] "Evaluation of Data Submitted in APPA's 2013 Distribution System Reliability & Operations Survey." American Public Power Association. March 2014.

[30] Note: APPA also reported SAIFI and SAIDI values from its 2007 report (which presumably used 2006 data) of 4.18 outages and 70 minutes, respectively.

[31] "Key Performance Metrics: Service Reliability." Hawaiian Electric Industries, Inc. March 10, 2016. <https://www.hawaiianelectric.com/about-us/key-performance-metrics/service-reliability>. Note: values are normalized to exclude major events.

ownership structures. What FEP can infer, however, is that HELCO's Hawaii Island service territory has historically experienced more frequent power interruptions than has HECO's Oahu service territory, while the relative outage durations have remained similar across both islands.

2.5 Functional Considerations

If Hawaii decides to pursue an alternative utility ownership structure, a crucial determination must be made regarding the functional scope of the new utility: should the utility attempt to acquire and operate the entire vertically-integrated system of HECO and HELCO's generation, transmission and distribution assets? Or, should the utility acquire only transmission and distribution assets, leaving generation (i.e. power plants) under investor ownership and management? The answer to these questions will undoubtedly have major implications on the acquisition costs, operating costs, staffing requirements, level of regulatory oversight, and potential stranded costs for which the new utility entity might be liable. FEP outlines these considerations in the following subsections.

2.5.1 Functional Components of an Electric System

An electric power system is composed of three primary processes. First, electric **generation**, such as power plants fueled by coal, natural gas, petroleum products, water, and renewable wind or solar, produces electricity.

Next, the electricity must be transmitted to load centers, such as towns and cities, where consumers will utilize the electricity. The **transmission** process requires that the electricity produced at the plants be converted or "stepped-up" to the appropriate voltages for long-distance transmission. Substations at each power plant step-up the electricity to voltages generally ranging between 69 kilovolts ("kV") and 345 kV. The high voltage electricity can then be efficiently transmitted anywhere that transmission lines have been constructed and connected.

Once the electricity reaches the load center, a reverse process must be conducted to "step-down" the voltage to levels suitable for shorter-distance **distribution** (typically 13 to 25 kV). Finally the distribution system transmits the electricity to local areas of consumers (such as neighborhoods or business districts) where the voltage can be stepped-down to its final levels (generally 120 volts or 240 volts for residential applications and higher voltages for commercial applications) for delivery to consumers.

The final step of the process is the consumption of the electricity by consumers in equipment, machines, computers, or any other electrical components. Ultimate consumers of electricity generally fall into customer classes of industrial, commercial, and residential.

The graphic in Figure 2-1 outlines the three processes of electric generation, transmission, and distribution.

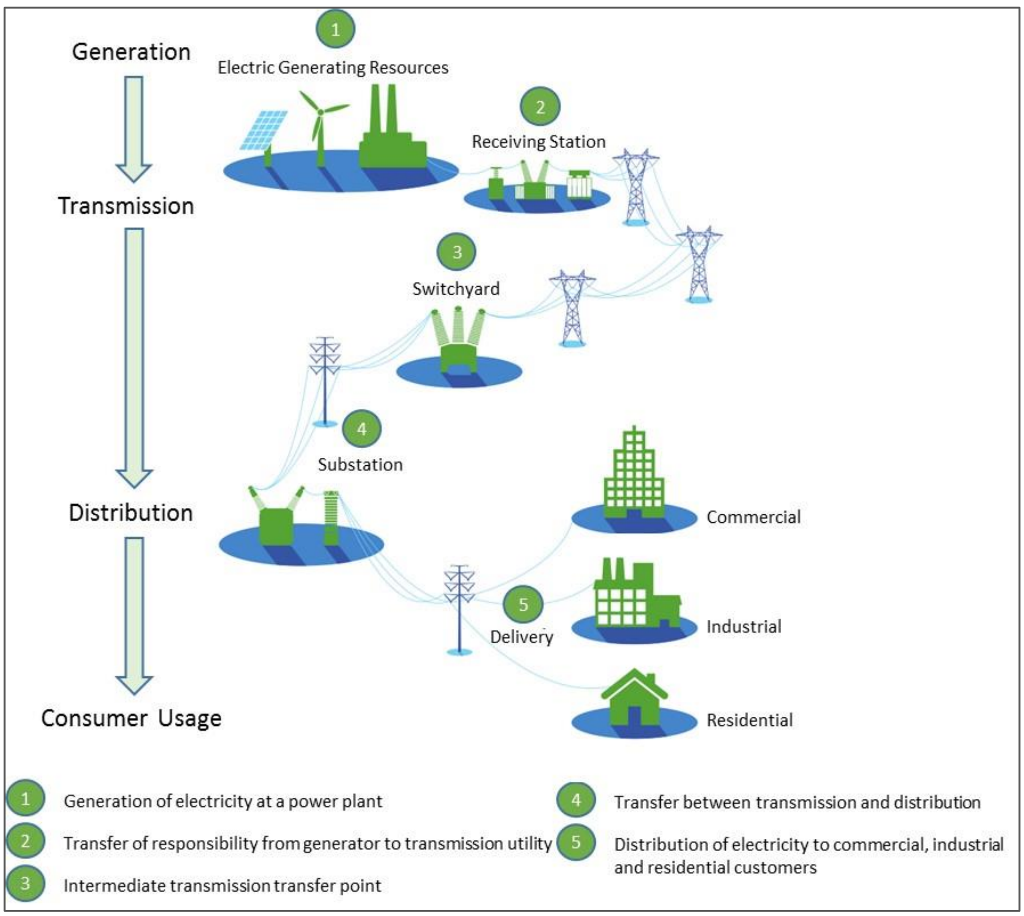

Figure 2-1: Overview of the Electric Power Industry[32]

[32] Filsinger Energy Partners

2.5.2 **Acquisition Cost Implications**

The Hawaii Public Utilities Commission ("HPUC") requires that all utilities in the state submit an annual financial and statistical report on their operations.[33] The contents of these reports are modeled on the standardized utility accounting methods utilized by the FERC in its annual Form 1 filings. As of this writing, 2014 annual reports to HPUC were available for HECO, HELCO, and KIUC. FEP analyzed the two relevant HEI subsidiary filings to determine functional breakouts of original costs for the "Electric Plant in Service" categories, which comprise the majority of utility assets. Figure 2-2 and Figure 2-3 below illustrate the percentage of original costs attributable to generation, transmission, distribution, and general (e.g. administrative buildings, vehicles, etc.) categories.

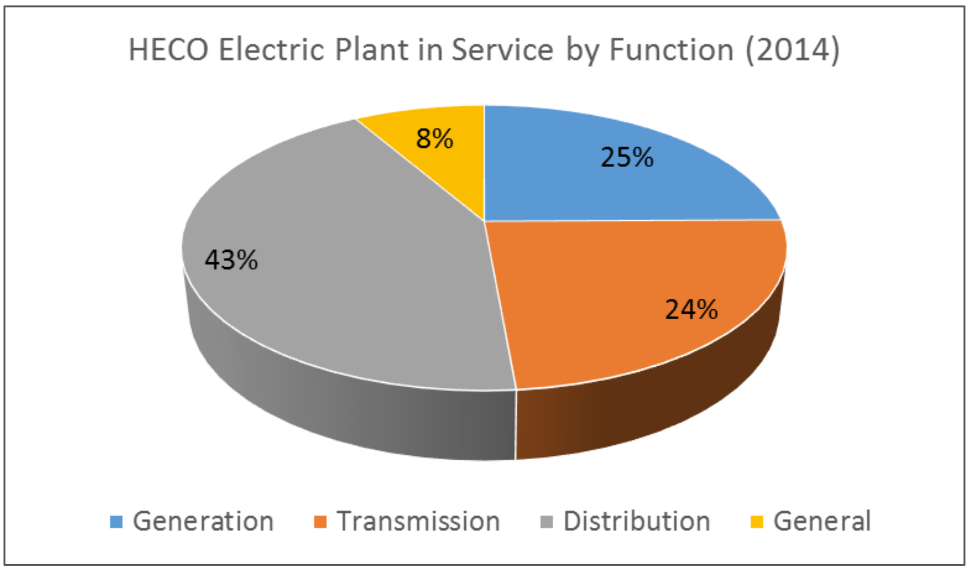

Figure 2-2: HECO Electric Plant in Service by Function (2014)[34]

[33] Hawaii Public Utilities Commission General Order No. 7 § 2.3(h)(1)

[34] "Annual Report of Hawaiian Electric Company, Inc. to the Public Utilities Commission State of Hawaii for the Year Ending December 31, 2014." Hawaiian Electric Industries, Inc. May 29, 2015.

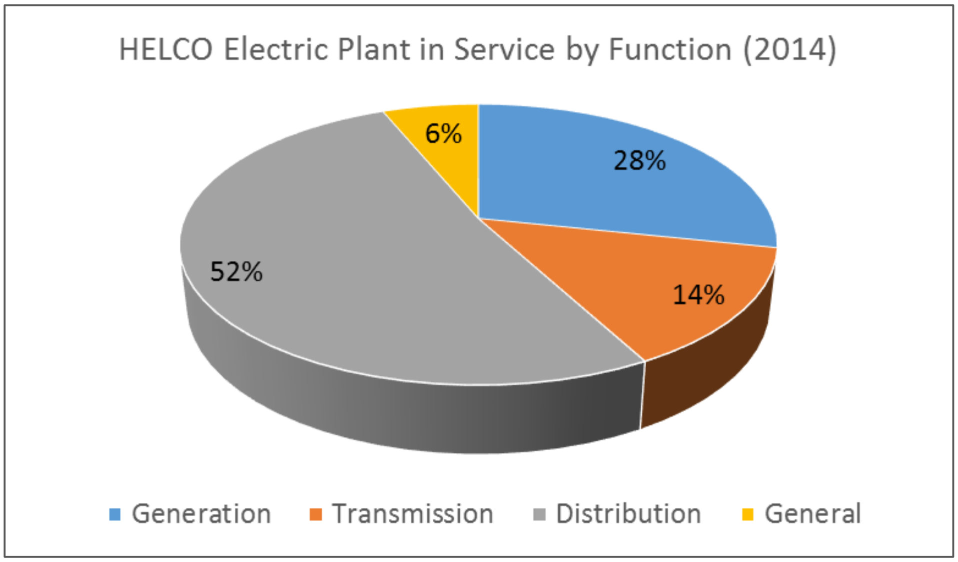

Figure 2-3: HELCO Electric Plant in Service by Function (2014)[35]

As can be seen above, on a percentage basis, the original cost of generation assets accounted for 25% and 28% of HECO and HELCO's utility plant, respectively. Because these two systems are not of equivalent size, their combined weighted average generation percentage is 26%.

One could assume that the acquisition cost of a transmission and distribution-only utility should be 26% lower than one which also includes generation. However, this supposition may not be correct. While it provides a ballpark estimate, in actuality the amount of accumulated depreciation, as well as ages and historical cost escalation rates for assets within each functional class, among other factors, would influence the relative purchase prices of HECO and HELCO's assets on either a transmission and distribution-only basis, or as a complete vertically-integrated utility, which includes generation. FEP explains the cost approach to valuation in greater detail in Section 3.3.2.

2.5.3 Other Cost Implications

Operating and maintenance costs for a transmission and distribution-only utility would be lower than for a utility that also included generation. However, the former utility structure would incur

[35] "Annual Report of Hawaii Electric Light Company, Inc. to the Public Utilities Commission State of Hawaii for the Year Ending December 31, 2014." Hawaiian Electric Industries, Inc. May 29, 2015.

higher purchased power expenses, which would flow through to rates, leaving an ambiguous net impact to the costs paid by electric power consumers.

Under a transmission and distribution-only utility scenario, power would be purchased from third-party suppliers, comprised possibly of a generation cooperative and/or for-profit, investor-owned companies. A transmission and distribution-only utility could also choose to solicit applications for the construction of new generation facilities. The new utility would contract for power, deliver it to customers, and operate financially on the margin charged to those customers. In addition to contracting and delivering power from third-party generators, a transmission and distribution-only utility would be responsible for the construction, maintenance, and improvement of the islands' transmission and distribution facilities, the costs of which operations would be recovered through customer rates.

If the new utility decided to procure a higher percentage of renewable energy, it could enter into purchased power agreement contracts with existing or new wind, solar, biomass, ocean, or geothermal generators. To the extent that existing, rate-regulated generation assets owned by HECO and HELCO are unable to recover the costs of their investments, so-called "stranded costs" may exist. Power purchase contracts which are not assumed may also trigger stranded costs. A new transmission and distribution-only utility may be liable if stranded costs exist. However, FEP recommends further analysis and legal consultation to determine whether or not stranded costs would be an issue. The full acquisition of HECO and HELCO's generation assets would likely mitigate any of these costs, if they are deemed to exist.

A more detailed overview of operating and maintenance costs, as well as staffing levels, is provided in Section 4.2. A summary of advantages and disadvantages of each utility structure is shown in Table 2-1.

Table 2-1: Advantages and Disadvantages of Utility Generation Ownership

	Transmission and Distribution-Only Utility	Generation, Transmission, and Distribution Utility
Advantages	• Lower acquisition costs • Lower operating and maintenance costs • Lower staffing requirements • Fewer technical specialists required • Smaller balance sheet • Fewer regulatory and reporting requirements • Ability to solicit competitive bids from third-party power producers	• Owned generation provides a natural hedge against increases in market power prices • Ease of scheduling and dispatching owned generation • Limited or no stranded costs for purchased generation assets • Ability to plan for asset retirements
Disadvantages	• Increased cost exposure to wholesale power prices • Potential for stranded generation costs • Additional resources required for power contracting	• Higher acquisition costs • Higher operating and maintenance costs • Higher staffing requirements • More technical specialists required • Larger balance sheet • Additional regulatory and reporting requirements

In addition to HECO and HELCO, several third-party electric power producers currently operate utility-scale generation assets on the islands. As is discussed in Section 4.2.1, HECO and HELCO currently purchase power from these independent producers, which supply roughly 26% and 34% of their firm generation capacity, as well as a substantial fraction of non-firm renewable energy capacity. A transmission and distribution-only utility would have several options of existing companies with whom to contract for purchased power.

2.6 CASE STUDY: City of Boulder, Colorado

For over a decade, the City of Boulder, Colorado, has been engaged in a process of exploration and formation of a municipal electric utility, for the stated purpose of procuring "clean, reliable, low-cost, local energy"[36] for its citizens. Throughout this process, Boulder has put forth several voter referendums, devoted significant personnel and financial resources, produced multiple studies, and engaged in extensive litigation against the incumbent investor-owned utility. As of early 2016, Boulder had formed a municipal electric utility on paper but had not yet received

[36] "About the Boulder Energy Future Project." City of Boulder, CO. <https://bouldercolorado.gov/energy-future/energy-future-about>

necessary approvals to condemn and acquire assets. While Boulder's municipalization story is still evolving in the courts, the Colorado Public Utility Commission, and City government, its progress to date is summarized in the following case study.

2.6.1 Boulder's Municipalization Story

The City of Boulder, Colorado is a progressive university town, situated at the base of the Rocky Mountains, 30 miles northwest of Denver. Approximately 100,000 people reside in Boulder. Boulder's electricity needs are currently met by the Public Service Company of Colorado ("PSCo"), a subsidiary of Minneapolis-based Xcel Energy. Boulder's electric load consists primarily of residential and commercial customers, with at least one large industrial. Boulder is estimated to have roughly 50,000 customer accounts, and the City uses approximately 1,500 gigawatt-hours ("GWh") of electricity per annum, with a retail peak demand of approximately 255 megawatts ("MW").[37,38] (For comparison, in 2015 HELCO served approximately 84,000 customer accounts on Hawaii Island, using over 1,143 GWh of electricity with a net peak demand of 191 MW, while HECO served approximately 303,000 customer accounts on Oahu, using 7,086 GWh of electricity with a net peak demand of 1,206 MW.[39])

In August 1990, Boulder granted PSCo an exclusive 20-year franchise to serve the City's electric power needs. In anticipation of the expiration of this franchise agreement, Boulder engaged a consulting firm in 2005 to explore the financial and technical feasibility of creating a municipal electric utility.[40] The consultant initially considered the feasibility of municipalizing PSCo's natural gas distribution infrastructure, as well as all electric generation, transmission, and distribution assets that served the City. However, for data availability and financial reasons that became apparent upon closer review, the study ultimately considered only electric distribution assets.[41]

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[37] Customer count based on census data and FEP research.

[38] "Request for Proposals, Partial Requirements Wholesale Electric Power Supply." City of Boulder, Colorado. April 16, 2015. <https://www-static.bouldercolorado.gov/docs/Boulder_Wholesale_Power_RFP-1-201504211340.pdf>

[39] "2015 Annual Report to Shareholders." Hawaiian Electric Industries, Inc. 2016. pp. 4-6.

[40] "Preliminary Municipalization Feasibility Study." R.W. Beck, Inc. October 2005.

[41] Ibid. "Operating a generation station, participating in the wholesale power market, and adding FERC oversight to the operations and management responsibilities of the City will significantly add to the complexity of a utility startup…The

The report focused its efforts on conducting a preliminary fair market valuation of the City's electric distribution assets, using the limited data provided by PSCo, and presented several "action items" that it recommended Boulder address within the following year to more clearly determine whether a municipalization attempt was warranted. These recommended action items included the compilation of a detailed inventory of system assets, a design study detailing how to physically sever the City's proposed system from the existing PSCo system, exploration of potential sources of wholesale electricity procurement (both purchased power and renewable energy development), an analysis of potential "stranded costs" owed to PSCo, and a study of customer load profiles and potential rate design.

Over the following year and a half, Boulder's city staff engaged with neighboring municipal electric utilities to estimate operating and startup costs as well as requirements for formation of its own municipal utility. In February 2007, Boulder released a detailed estimate of its anticipated costs, personnel, and overhead assets (e.g. vehicles and maintenance tools).[42] Boulder's report estimated annual operating costs of approximately $16 million, of which nearly $4.5 million were attributable to labor costs associated with its proposed staff of 71 full-time employees. The report also predicted that certain resources devoted to its existing municipal water utilities[43] had the potential to yield economies of scale and provide some cost savings.

In 2010, Boulder let the 20-year franchise agreement with PSCo expire – a first step towards breaking ties with the incumbent utility. Because PSCo continued to provide electricity to the City without a franchise, it was no longer subject to the 3% franchise fee. To replace this City revenue stream, and to fund municipalization exploration activities, City voters approved a ballot measure in November 2010 that implemented a "utility occupation tax" of $4.1 million.[44]

City should exclude generation and transmission assets from this municipalization effort due to the cost of acquiring and maintaining these types of assets."

[42] "Electric Municipalization Project Administrative and Operational Issues Report." City of Boulder. February 14, 2007.

[43] For example, existing resources associated with: meter reading, billing, call centers, credit and collections, remittance processing, and fieldwork staff

[44] Boulder, Colorado Municipal Code. Chapter 13 – Utility Occupation Tax.

In 2011, Boulder engaged an engineering firm to produce an updated feasibility study.[45] This study explored some of the legal, physical, and financial issues, and it reaffirmed the City's intention to pursue municipalization. This study also conducted a cursory analysis of financing requirements and estimated that the City would need to set aside upwards of $41 million (approximately one third of its then-estimated acquisition costs) in operating cash reserves, in order to qualify for creditworthiness with counterparties supplying wholesale power. It also assumed that 80% of municipalization costs (i.e. acquisition costs, operating cash reserves, severance costs) would be financed with taxable debt, while the remaining 20% (i.e. start-up logistics, legal and engineering costs, spare equipment) could be financed by tax-exempt issuances. This split is not fully explained but seems consistent with FEP's understanding of the "Rostenkowski amendment," which prohibits public entities from issuing tax-exempt debt to acquire private utility assets.

Also in 2011, Boulder voters approved dual ballot referendums which:

- Increased the utility occupation tax by up to $1.9 million per year; and
- Allowed the City to establish and debt-finance a municipal electric utility, if it could determine that customer rates would be the same or cheaper than PSCo's rates.

The former measure garnered 50.27% of the vote, passing by an extremely slim 141-vote margin.[46] These two measures established the critical financial and legal prerequisites for the City to proceed with more detailed analysis of municipalization options.

With funding from the increased utility occupation tax, Boulder created a new job position for an executive director of energy strategy and electric utility development, which it filled in mid-2012 with the hiring of Heather Bailey. At an annual salary of $250,000, excluding a $31,000 housing stipend, Ms. Bailey became the City's highest-paid employee.[47] Over the following year, Ms.

[45] "Boulder Municipal Utility Feasibility Study." Robertson-Bryan Inc. August 16, 2011.

[46] "Boulder municipalization (2B and 2C)." Boulder Weekly. November 1, 2011. <http://www.boulderweekly.com/news/boulder-municipalization-2b-and-2c/>

[47] Boulder's second-highest employee, the City Manager, was paid at the time less than $197,000 per year.

Bailey mustered City resources and external consultants to explore and model whether a municipal utility could be expected to meet the voter mandate of cheaper rates, while procuring increased renewable energy. In the summer of 2013, the City and its consultant found that this was possible, and the Boulder City Council approved dual ordinances establishing authority to condemn PSCo assets and declaring that a municipal utility would meet the requirements of the 2011 voter referendum.

During the 2013 election cycle, Boulder voters faced two more ballot initiatives, which dealt with financing the proposed municipal electric utility. One measure, which would have mandated future voter approval for any debt issuances, failed. The other measure passed and, among other things, placed a ceiling of $214 million on financed acquisition costs and lump-sum stranded costs.

In May 2014, the Boulder City Council unanimously approved the formation of a municipal electric utility. This action established the utility in name only; the City did not yet own or operate any assets. PSCo promptly sued Boulder in June to revoke its utility charter, arguing that Boulder failed to prove that its electric service would be as reliable and cost-competitive as PSCo's while also lowering greenhouse gas emissions. The Boulder District Court promptly dismissed this case on procedural grounds, stating that PSCo should have appealed after the City Council's summer 2013 determination that a utility would meet the requirements of the 2011 voter referendum.

Boulder went back to the District Court in July, to petition to condemn PSCo's assets. The following month, Boulder's consultant released a Transition Plan,[48] which detailed a proposed timeline for completing acquisition and utility formation activities. This plan envisioned a two-year lead time until the City would take ownership of PSCo's assets, in September 2016. The plan then assumed that an additional two years would be necessary until "separation and reintegration is complete at wholesale delivery points and Boulder assumes full operation" in

"Boulder's new energy director to be city's highest-paid employee, at $250K a year." Daily Camera. April 19, 2012. <http://www.dailycamera.com/ci_20432800/boulder-hires-heather-bailey-oversee-possible-municipal-utility>

[48] "Report of Transition Planning for New Electric Utility." PowerServices, Inc. August 12, 2014.

August 2018.[49] In early 2015, Boulder issued a request for proposals[50] seeking a provider of wholesale electric power for a five-year period commencing in 2018. Unusually, this request specifically asked PSCo to bid.

The City hit a roadblock in February 2015, when the District Court dismissed the condemnation suit, stating that the City needed to first seek permission from the Colorado Public Utilities Commission, per an earlier ruling. Boulder chose not to appeal this decision and proceeded to file its case with the Commission in July 2015.[51] PSCo filed a motion to dismiss this case in August, and the Commission partially approved this motion in November.[52] As of early 2016, Boulder was in the process of conducting discovery and drafting an amended condemnation application. Should condemnation be approved, Boulder will be then be in a position to proceed with other aspects of its Transition Plan.

2.6.2 Boulder's Municipalization Costs and Budget

In late 2015, Boulder staff released a financial summary of the City's historical and budgeted costs related to its municipalization efforts.[53] This summary indicated that between 2012 and 2015 the City had spent over $6.9 million. Much of this was funded by the City's utility occupation tax, the costs of which were paid by PSCo but passed through to city residents through a bill surcharge. The City requested a revised budget for 2015 through 2017 of nearly $7.9 million. This number appears to exclude capital costs, as well as the costs of other City staff resources, which may

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[49] Ibid.

[50] "Request for Proposals, Partial Requirements Wholesale Electric Power Supply." City of Boulder, Colorado. April 16, 2015. <https://www-static.bouldercolorado.gov/docs/Boulder_Wholesale_Power_RFP-1-201504211340.pdf>

[51] See: Colorado Department of Regulatory Affairs, Docket No. 15A-0589E.

[52] The lynchpin of this "partial" dismissal rested on Boulder's proposed plan to acquire certain PSCo electric distribution assets outside of the City, which would then be used to wheel electricity back to PSCo customers outside of the City. Because of the interconnected nature of Boulder's electric grid, the fact that it was not designed with municipal boundaries in mind, as well as the fact that numerous citizens residing outside the City or within unincorporated pockets surrounded by City territory are served by the same infrastructure as City citizens, the question of how to separate the electric system into two independently owned and operated entities has presented unique technical and legal challenges. It is important to note that these challenges may not exist on an island system, which is owned in whole by a single entity.

[53] "Information Packet Memorandum." Brautigam, Jane. October 20, 2015. <https://documents.bouldercolorado.gov/WebLink8/0/doc/130620/Electronic.aspx>

contribute to the municipalization effort, but which are funded via existing payrolls for other City projects. Over half of the revised 2015 budget of approximately $3.9 million is related to "Consulting and Contract Services," which includes Transition Plan, legal, and regulatory advisory. Proposed funding comes from the utility occupation tax, as well as from the City's general fund.

2.7 CASE STUDY: Kauai Island Utility Cooperative

The Kauai Island Utility Cooperative, which prides itself as "America's newest electric cooperative,"[54] is a member-owned electric power provider currently serving Hawaii's Garden Isle. KIUC purchased the assets of the incumbent investor-owned utility, Kauai Electric, in 2002. KIUC's experiences in acquiring and operating the Kauai's electric grid provide a contemporary and locally-relevant case study in cooperative utility management.

2.7.1 KIUC's Story

"KIUC was formed, pursuant to the provisions of [Hawaii Revised Statutes] Chapter 421C, as a non-profit cooperative association by a group of Kauai business leaders and professionals for the purpose of acquiring [Kauai Electric]."[55] In February 2000, KIUC and Citizens Utilities Company, the parent of Kauai Electric, entered into a purchase and sale agreement for the utility properties of Kauai Electric for the consideration of $270 million. The transacting parties submitted an application for approval of the transaction to the HPUC in April 2000. In August of that year, the HPUC denied the application on the grounds that the risks of KIUC ownership outweighed potential benefits, that KIUC was not financially fit to own and operate Kauai Electric, and that the transaction was not in the public interest.

Nearly two years later, in March 2002, the parties resubmitted an amended and reinstated purchase and sale agreement to the HPUC, with a revised purchase price of $217.5 million (including $2.5 million in transaction costs) and improved financing conditions. This purchase price was based on a value of net assets of $180.4 million, plus an acquisition premium of $37.1

[54] "About Us." KIUC. March 3, 2016. <http://website.kiuc.coop/content/about-us>

[55] "Application of Citizens Utilities Company and Kauai Island Utility Co-op for Approval of the Sale of Certain Assets of Citizens Utilities Company, Kauai Electric Division and Related Matters." HPUC Docket No. 00-0108. April 6, 2000.

million, as of January 1, 2001. At the time of valuation, the physical assets in service had a combined original cost of $283 million and a book value of $168 million.[56,57] At the date of HPUC application, KIUC had already obtained a financing commitment from the National Rural Utilities Cooperative Finance Corporation ("CFC") and was in the process of obtaining financing from the U.S. Department of Agriculture's ("USDA") Rural Utilities Service ("RUS").[58] Over the following month, various stakeholders intervened in the case, including the Department of the Navy, the Consumer Advocate, and the County of Kauai. In May 2002, the HPUC issued a procedural order, which outlined nine questions to be addressed during the acquisition hearings.[59] These included:

- Whether the purchase and sale agreement should be approved;
- Whether the assignment of Kauai Electric's franchise to KIUC should be approved;
- Whether the sale of all of Kauai Electric's assets should be approved;
- Whether KIUC's proposed financing should be approved;
- Whether KIUC is "fit, willing and able to perform the services currently offered by the utility";
- Whether KIUC's acquisition of the Kauai Electric assets is reasonable and in the public interest;
- Whether it is reasonable for KIUC to use the then-current Kauai Electric rates, tariffs, and rules and regulation for its financial projections;
- Whether any other relief should be granted; and
- Whether any other conditions or provisions are required to ensure that the proposed transaction is in the public interest.

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[56] Ibid.

[57] Construction work in progress contributed approximately $6 million of additional physical assets

[58] "Application of Citizens Communications Company, Kauai Electric Division and Kauai Island Utility Co-op for Approval of the Sale of Certain Assets of Citizens Communications Company, Kauai Electric Division and Related Matters." HPUC Docket No. 02-0060. March 15, 2002.

[59] "Procedural Order No. 19397." HPUC Docket No. 02-0060. May 31, 2002.

In September 2002, the HPUC approved the transaction, subject to the terms of a joint stipulation agreed-to by the applicants and a consortium of intervening parties. [60] These final terms included:

- One-time $3 million rebate to customers from Kauai Electric within one year of sale closing;
- Annual KIUC submission of achieved operating margins to RUS. Based on calculation, KIUC would recommend RUS approval for payment of patronage capital cash refunds to its members equal to 25% of reported prior period margin amounts;
- Disallowance of rate recovery of debt service on acquisition and transaction costs;
- Disallowance of rate recovery of goodwill or acquisition premium amounts;
- KIUC's agreement to not seek rate recovery of transaction costs or amortization;
- KIUC's preparation and submittal of a depreciation accrual rate study by mid-2004;
- KIUC's preparation and submittal of proposed revisions to integrated resource plan and demand-side management plans by end of 2003;
- KIUC's prompt notification to HPUC and Consumer Advocate of any significant investment of capital, labor or resources to new or planned business resources;
- KIUC's cooperation with Consumer Advocate in development of financial reporting standards for dissemination to KIUC members; and
- KIUC's review and submittal of Emergency Preparedness and Recovery Plan within 180 days of closing.

FEP believes that one may reasonably expect similar HPUC considerations and/or transaction stipulations in any new utility acquisition proceeding.

In November 2002, KIUC closed on the purchase of Kauai Electric's assets for a final purchase price of approximately $218 million, financed by loans from CFC and the federal government.[61]

In 2009, KIUC adopted a "primary goal" to use renewable generation for at least 50% of its power production by the year 2023.[62] Since that year, KIUC has increased renewable energy usage from

[60] Ibid.

[61] "Consolidated Financial Statements for Kaua'i Island Utility Cooperative: December 31, 2015 and 2014." EideBailly. March 15, 2016.

[62] "Journey 2014: KIUC 2014 Annual Report." KIUC. 2015.

13% to 37% by the end of 2015. This achievement has been driven by the construction of two 12MW commercial solar arrays, owned by KIUC, and the procurement of 7MW of purchased power generated from wood-based biomass. Green Energy Team LLC's independently-owned 7MW biomass facility was constructed at a cost of $90 million and will supply nearly 12% of Kauai's electricity demand, selling its power to KIUC under a 20-year agreement.[63] KIUC's large-scale commercial solar projects include the $40 million, 12MW Koloa array, which went online in August 2014, as well as the $54 million, 12MW Anahola array, which entered service in November 2015. The latter project, consisting of 59,000 panels assembled on 60 acres of land leased from the state's Department of Hawaiian Home Lands, is anticipated to eliminate the annual need for 1.7 million gallons of petroleum, reduce CO2 emissions by 18,000 tons per year, and generate approximately 20% of Kauai's electricity demand during sunny days. Additionally, this site contains a 6MW battery storage facility.[64] These commercial renewable projects on Kauai have been augmented by a nearly ten-fold increase in installed residential solar capacity between 2010 and 2015; approximately 10% of island customers now have residential solar.[65]

Because solar power is only available during the daytime hours, when the sun is shining, KIUC has explored additional storage technologies to enable the utilization of renewable solar energy at night. KIUC is engaged in the permitting process for a pumped storage hydropower facility and has already contracted to purchase power from a new third-party utility-scale battery storage facility anticipated to be completed by the end of 2016.

KIUC also installed 28,000 "smart meters" in 2013, which may allow users to better track real-time energy usage and enable the cooperative to test demand-side management strategies, such as time-of-use pricing.

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[63] Ibid.

[64] "Dedication, tours set for Anahola solar array." The Garden Island. November 3, 2015.

[65] "Overview." KIUC. March 4, 2016. <http://website.kiuc.coop/content/overview>

KIUC's status as a rural cooperative has made it eligible to participate in the USDA Rural Development grant program.[66] Through this revolving loan program, KIUC has been able to lend over a million dollars of no-interest loans to rural local businesses, such as the National Tropical Botanical Gardens, the Island School, and Kauai Brewers LLC.[67]

2.7.2 Economics and Regulatory Issues

2.7.2.1 Residential Rates

Since its inception, KIUC's residential rates have remained higher than the state average and, for at least the past ten years, fairly consistent with those of HELCO. It is important to note the allocation of costs to residential, commercial, and industrial ratepayers may differ between utilities and that FEP did not examine these allocations in detail. As shown in Figure 2-4, between 2006 and 2014, KIUC's variable rates (excluding fixed customer costs) ranged between $0.27 and $0.42 per kWh, while HELCO's rates ranged from $0.31 to $0.42 per kWh. During that same timeframe, HECO's rates were significantly lower and varied between $0.20 and $0.35 per kWh. Across all islands, electricity rates in Hawaii have typically been double to triple the amounts paid by mainland consumers. This fact is largely attributable to the high costs of importing fossil fuels to the islands.

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[66] Note that public entities are also eligible

[67] "Consolidated Financial Statements for Kaua'i Island Utility Cooperative: December 31, 2015 and 2014." EideBailly. March 15, 2016.

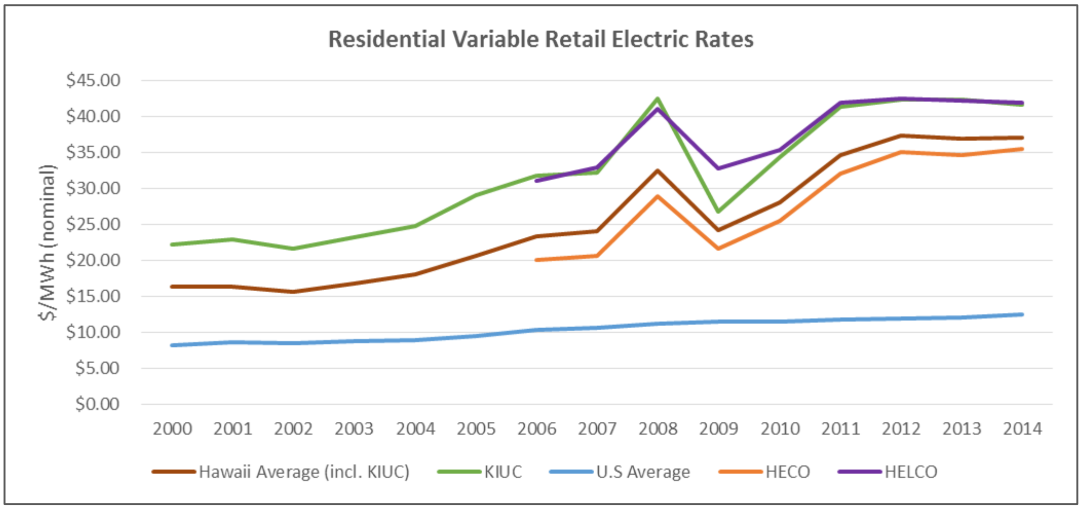

Figure 2-4: Residential Variable Retail Electric Rates[68]

Despite the higher costs of energy production in the state, the rate of growth of Hawaii's residential electricity rates since 2000 has stayed well below the growth in the price of #2 fuel oil. As shown in Figure 2-5, since approximately 2008, KIUC's rates have grown more slowly than the state average.

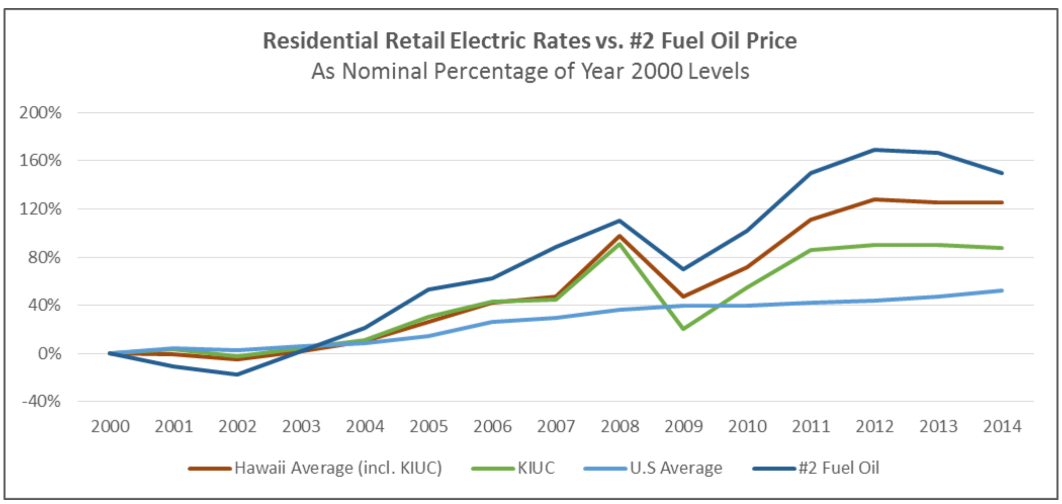

Figure 2-5: Residential Variable Retail Electric Rates vs. #2 Fuel Oil Price[69]

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[68] Based on analysis of:
"Rates." KIUC. March 29, 2016. <http://website.kiuc.coop/content/rates>
"Average Price by State by Provider (EIA-861)." U.S. Energy Information Administration. March 17, 2016.
"Cost of Final Delivered Energy to Customers by Rate Class for Each Island System." Hawaiian Electric Company, Inc. February 5, 2016.
<https://www.hawaiianelectric.com/Documents/key_performance_metrics/07/historical_TOU_020516.xlsx>

2.7.2.2 **Financing and Capital Structure**

According to its latest audited financial statements,[70] KIUC was capitalized with approximately 39% equity and 61% long-term debt.[71] Approximately 67% of the cooperative's long-term debt is currently comprised of fixed and variable notes payable to RUS, maturing in 2027. Roughly 30% consists of fixed and variable notes due to the Federal Financing Bank, with 2023 and 2042 maturities. The CFC holds approximately 2% of KIUC's long-term debt, in the form of a fixed note due in 2023. Additionally, the cooperative holds a variable construction loan that has been converted to a fixed note, and it participates in the RUS's Cushion of Credit Payment Program, which is described in Section 3.2.1. KIUC maintains "a perpetual $60,000,000 disaster line of credit, a perpetual $5,000,000 line of credit for short-term financing, a 3-year $20,000,000 line of credit for construction financing with CFC, and a 3-year non-revolving line of credit with CFC in the amount of $70,000,000 to finance construction [of a commercial solar project], all at a variable interest rate."

As a cooperative, KIUC is owned by its approximately 23,000 member ratepayers.[72] These members contribute "patronage capital" by paying rates that exceed operating expenses, and this capital forms the basis of KIUC's equity investment. Since 2002, KIUC has refunded over $32 million to its members, in the form of patronage capital retirements and billing credits.[73]

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[69] Based on analysis of:

"Rates." KIUC. March 29, 2016. <http://website.kiuc.coop/content/rates>
"Average Price by State by Provider (EIA-861)." U.S. Energy Information Administration. March 17, 2016.
"Data 1: Weekly U.S. Weekly No. 2 Heating Oil Residential Price (Dollars per Gallon)." U.S. Energy Information Administration. March 17, 2016.
<https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=W_EPD2F_PRS_NUS_DPG&f=W>

[70] "Consolidated Financial Statements for Kaua'i Island Utility Cooperative: December 31, 2015 and 2014." EideBailly. March 15, 2016.

[71] Ibid.

[72] "About Us." KIUC. March 3, 2016. <http://website.kiuc.coop/content/about-us>

[73] "Journey 2014: KIUC 2014 Annual Report." KIUC. 2015.

2.7.2.3 Bylaws

KIUC's bylaws stipulate that all electricity users can elect to become a member of the cooperative for a price not to exceed $100. Each member receives one vote, regardless of their electricity consumption, at the annual member meeting and on all other topics brought to a vote.[74]

2.7.2.4 Regulatory Oversight

While regulatory oversight of electric cooperatives varies between states, and many states allow cooperatives and municipal entities to self-govern, the HPUC maintains regulatory powers over KIUC. Among other things, these HPUC powers pertain to ratemaking as well as the approval of utility mergers and acquisitions.[75] Similar regulatory authorities would most likely apply to other Hawaii electric cooperatives. This fact may translate to higher regulatory overhead requirements for cooperatives and municipal utilities in Hawaii than in less-regulated states. It is unclear to what extent KIUC utilizes internal versus external legal counsel, and the costs associated with these business functions.

2.7.2.5 Taxation and Fees

Per Section 501(c)(12) of the Internal Revenue Code, "mutual or cooperative electric companies" that receive at least 85% of their income from members are largely exempt from federal income taxes.[76] Per Hawaii Revised Statutes ("HRS"), KIUC must pay state income taxes but is allowed certain deductions. New cooperatives would most likely be subject to similar state income taxation. As of 2015, the state also assessed KIUC a Public Service Company Tax in the amount of 5.885% of gross revenues[77] as well as a 0.5% Public Utility Commission Fee.[78] KIUC does not pay

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[74] "Seventh Revised and Restated By-Laws of Kauai Island Utility Cooperative." KIUC. March 28, 2009. <http://website.kiuc.coop/content/bylaws>

[75] Hawaii Revised Statutes §269

[76] IRC § 501(c)(12). Note that "unrelated business income" is taxable.

[77] Per Hawaii Revised Statutes §239-5, public utilities are assessed a 4% tax on gross revenues plus a variable rate determined by the ratio of net to gross income, starting at 1.885%.

[78] Hawaii Revised Statutes §269-30

general excise taxes or county real property taxes but is assessed a 2.5% franchise fee on gross revenues by the County of Kauai.[79,80] Similar franchise fees may be anticipated on Hawaii and Oahu Islands, as well as for municipal or investor-owned utilities; however, these expenses are county-specific and subject to each jurisdiction's requirements.

2.8 Other Examples of Electric Cooperatives and Public Power

2.8.1 Electric Cooperatives

The vast majority of cooperative electric utilities were formed during the 1930s and 1940s in rural areas that lacked pre-existing electric service. As shown in Figure 2-6 below, since the dawn of the new millennium only 22 existing cooperatives were incorporated, representing only 2.4% of the over 900 cooperatives currently in service. A quick survey of each cooperative's website revealed that nearly all of these cooperatives were reorganizations or mergers of existing cooperatives.

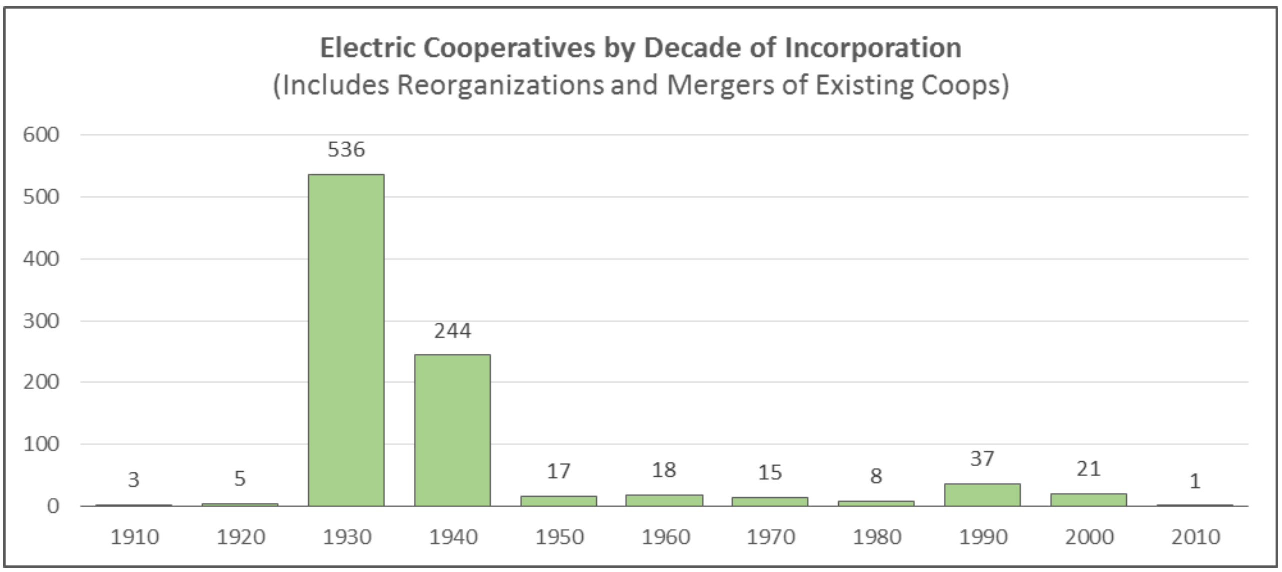

Figure 2-6: Electric Cooperatives by Decade of Incorporation[81]

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[79] "Consolidated Financial Statements for Kaua'i Island Utility Cooperative: December 31, 2015 and 2014." EideBailly. March 15, 2016.

[80] Hawaii Revised Statutes §240-1

[81] Data derived from: "Electric Cooperative Growth: 1914-present." NRECA. March 25, 2016. <http://www.nreca.coop/wp-content/plugins/nreca-interactive-maps/coop-growth/index.html>

In recent history, outside of KIUC, there is virtually no precedent for cooperative utilities taking over the entire service areas and assets of investor-owned companies. However, there have been examples of cooperatives which have jointly owned power assets with investor-owned and/or public power entities.

Tri-State Generation and Transmission Association, Inc. ("Tri-State") provides an example of the joint ownership of electric infrastructure. Formed in 1952 and currently owned by 44 member cooperatives, Tri-State produces power and transmits it to the distribution systems that serve approximately 1.5 million consumers.[82] Tri-State serves a roughly 200,000 square-mile territory that encompasses large swaths of Wyoming, Nebraska, Colorado, and New Mexico.[83] Tri-State owns approximately 2.8 gigawatts of generation capacity, a portion of which is comprised of fractional ownership stakes in power plants jointly owned by other utilities. For example, Tri-State owns Unit 3 of the three-unit, 1,303 MW Craig Generation Station in Colorado, while it owns a 24% share in each of Units 1 and 2, which are co-owned by two investor-owned utilities (PSCo and PacifiCorp) and two public power organizations (Platte River Power Authority and Salt River Project).[84]

Information regarding most other electric cooperatives is available via cooperative websites and statistical publications from industry groups, such as the National Rural Electric Cooperative Association and CFC.

2.8.2 Public Power Organizations

Some of the largest cities and territories in the United States currently own and operate their electric power systems. The Puerto Rico Electric Power Authority and the Los Angeles Department of Water & Power each serve over 1.4 million customers in their respective regions

[82] "Overview." Tri-State Generation and Transmission Association, Inc. March 25, 2016. <http://www.tristate.coop/AboutUs/overview.cfm>

[83] Ibid.

[84] "Form 10-K Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal period ended December 31, 2015." Tri-State Generation and Transmission Association, Inc. 2016. <http://www.tristate.coop/Financials/documents/Tri-State%2010-K_03142016.pdf >

and constitute the largest public power utilities in the United States, when measured by the number of customers served.[85] The cities of San Antonio, TX and Sacramento, CA operate municipal electric utilities that serve approximately 750,000 and 610,000 customers, respectively. Public power utilities that serve over 200,000 customers each operate in cities as diverse as: Austin, TX; Jacksonville, FL; Seattle, WA; Memphis, TN; Nashville, TN; Omaha, NE; Orlando, FL; and Colorado Springs, CO.[86]

Austin Energy, founded in the 1895, is currently the seventh largest public power company in the United States by number of customers served.[87] In late 2014, the Austin City Council approved the municipal utility's long term plan, which laid out a strategy to significantly reduce greenhouse gas emissions by 2025. The so-called "500+ Plan" guides the utility to procure an additional 500MW of solar power, 375MW of wind power, and retire a coal plant by 2025, among other actions.[88]

As with electric cooperatives, there have been few successful municipal acquisitions of investor-owned electric power systems in recent memory. One exception to this trend was the City of Winter Park, Florida. Another exception was the Jefferson County Public Utility District ("JPUD") in the state of Washington.

Upon expiration of a 30-year franchise agreement in 2001, the City of Winter Park, Florida proceeded to exercise its contractual option to purchase its distribution system from Progress Energy Florida, the incumbent investor-owned utility. The system served approximately 13,000 customers. Both sides hired expert witnesses who arrived at drastically different valuations (approximately $16.5 and $70 million). The City and the seller proceeded to arbitration, and in 2003 the arbitrator ruled that the system was worth $31 million with an additional $11 million

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[85] "2015-2016 Public Power Annual Directory & Statistical Report." American Public Power Association.

[86] Ibid.

[87] Ibid.

[88] "Investing in a Clean Future: Austin Energy's Resource, Generation and Climate Protection Plan to 2020 Updates." Council Committee on Austin Energy. December 4, 2014. <http://austinenergy.com/wps/wcm/connect/554c421b-e743-4b29-be29-149ff9bd198e/aeResource+PlanCCAEv1020141204.pdf?MOD=AJPERES>

due for stranded costs.[89] In 2005, the City successfully purchased the system and commenced municipal operations. The City Manager estimated that between 2005 and 2011 the City's residential electric rates averaged approximately 0.34% higher than the investor-owned utility's rates.[90]

In 2008, a voter referendum allowed JPUD to form an electric utility. Two years later, Puget Sound Energy contracted to sell the local distribution system, which served approximately 18,000 customers, to JPUD for a sum of $103 million.[91] JPUD obtained financing from the USDA RUS program and secured low-cost power procurement from the Bonneville Power Administration.[92] The transaction closed in March 2013. The state Utilities and Transportation Commission later ruled that Puget Sound Energy must return "about $59.2 million" to ratepayers in its remaining (i.e. non-Jefferson County) service territories, amounting to a one-time credit that would "save the average residential electric customer about $40."[93]

The above section has presented anecdotes from a small sampling of the large cohort of public power organizations across the United States. More information can be found through municipal websites and the American Public Power Association.

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89 "Order on Motions to Correct Arbitration Award." In the Circuit Court of the Ninth Judicial Circuit in and for Orange County, Florida. July 22, 2003.

90 Knight, Randy. "City of Winter Park: Our Municipalization Story. Presentation to South Daytona."

91 "Puget Sound Energy sells system for $103M to Jefferson County PUD." Puget Sound Business Journal. May 4, 2010. <http://www.bizjournals.com/seattle/stories/2010/05/03/daily18.html>

92 "Annual Financial Report for the Years Ended December 31, 2012, 2011, 2010." Public Utility District No. 1 of Jefferson County, Washington. Reissued: March 24, 2014.

93 "PSE gives customers $40 credit for sale of system to PUD." Port Townsend Leader. November 19, 2014. <http://www.ptleader.com/news/pse-gives-customers-credit-for-sale-of-system-to-pud/article_62572172-6f80-11e4-9cfb-2bcaec33059b.html>

3 FINANCING ANALYSIS

As previously discussed in Section 2.1, access to both public and private capital markets can take the form of debt or equity. There are additional structures available that are hybrid debt/equity instruments; however, FEP's analysis has generally focused on standard equity and debt instruments. A general overview, benefits, and considerations of these types of capital is summarized in Table 3-1 below.

Table 3-1: Overview, Benefits, and Considerations of Equity vs. Debt Financing

	Equity	Debt
Overview	• Long-term capital; can be public or private • Represents ownership interest in the issuing entity • Shareholders require return of capital (e.g. dividends, share repurchases) and return on capital (e.g. capital appreciation)	• Fixed-term capital; can be short, medium, or long-term • Can be public or private • Can be floating or fixed-rate • Does not represent ownership interest in the issuing entity • Investors expect interest and principal repayment
Benefits	• Generally most flexible form of capital • Public equity markets relatively easy to access once equity is publicly traded • Equity offerings can be more easily sized to company's needs	• Typically lower cost compared to equity capital • Interest expense is typically tax deductible (if entity is subject to taxes) • Structure can be negotiated to fit the needs of the borrower • Variety of sources across public and private markets (e.g. bank loans, term loans, notes, and bonds)
Considerations	• Typically more expensive compared to debt capital • Return of capital to shareholders subject to double-taxation (note: some utilities are currently exploring a real estate investment trust "REIT" structure, which could allay tax burden) • Publicly traded equity subjects company to oversight by the SEC, including reporting and disclosure requirements	• Can carry restrictive covenants • Typically requires capital to be raised in large quantities • Requires ongoing management of maturity profile • Subject to refinancing risk upon debt maturity • Publicly traded debt subjects company to oversight by the SEC, including reporting and disclosure requirements

3.1 Financing Considerations

Whether the islands of Hawaii and Oahu choose to pursue municipal, cooperative, or investor ownership structures will largely impact the types and sources of debt financing available to acquire and operate an electric utility. While FEP recommends that a financial advisor should be consulted to explore financing specifics, should the islands choose to move forward with alternative ownership plans, a high level overview of the various options is presented below.

3.1.1 Public and Private Capital Markets

Public and private capital markets are available to a variety of corporate structures. If Hawaii chooses to create an investor-owned utility, that entity would be able to access both public and private markets to raise either debt or equity capital.

Equity capital could come in the form of public equity (public offering of equity in the entity) or private equity (equity investment from a private equity fund, institutional investor(s), or other private capital). The requirements and considerations for issuing equity would depend highly on the type of equity capital raised and the investor(s) in the utility entity.

An investor-owned corporate structure would also have access to the debt markets, both public and private, regardless of whether the equity in the utility entity is traded on the public markets or is privately held. Debt issued in the public corporate debt markets would be subject to oversight by the SEC and would require compliance with certain financial disclosure requirements, depending on how the debt is registered. The entity could also raise debt capital in the form of bank loans (credit facilities, working capital facilities, term loan debt) or private markets through institutional investors, private equity funds, or other private capital.

Debt capital that is raised through the public markets will be subject to the current market terms and covenants. Debt capital that is raised through the bank or private markets will be highly negotiated between the investor and the utility, and terms and covenants can be negotiated to suit both the debtor and the creditor. All debt capital raised through either of these markets will require entering into an indenture that contains the terms and conditions of the debt.

Most debt instruments will require the maintenance of one or two credit ratings issued by the credit ratings agencies Standard & Poor's, Moody's, and Fitch. In addition, the issuing entity will be subject to both affirmative and negative covenants. Affirmative covenants require the issuing entity to take certain actions, such as compliance with financial reporting and disclosure regulations. Negative covenants restrict the ability of the entity to engage in certain activities, the most common of which is the restriction on additional indebtedness above certain limits. Restrictions on indebtedness are typically governed by financial ratios, such as leverage ratios (e.g. Total Debt / EBITDA), interest coverage (e.g. EBIT / Interest Expense), or tangible net worth covenants.

3.1.2 Municipal Debt

Publicly-owned utilities – and in some instances cooperative and investor-owned utilities –would have the ability to raise capital using municipal debt. The municipal debt markets are public markets; however, the issuing entities and tax treatment of interest differentiate this market from the public markets discussed above.

The Hawaii state constitution authorizes the legislature to issue four types of municipal debt instruments: general obligation bonds ("GO bonds"), bonds issued under special improvement statutes, revenue bonds, and special purpose revenue bonds ("SPRB"s). Depending on the ultimate ownership structure selected, a newly-formed utility could potentially utilize three of these options: GO bonds, revenue bonds, or SPRBs. All municipal debt is subject to limits on total outstanding indebtedness as governed by the state constitution. Following is a description of the types of municipal debt instruments potentially available:

- **GO bonds:** GO bonds are backed by the faith and credit of the state or municipality issuing the bonds. Principal and interest payments are funded using tax receipts received by the municipality. Interest paid on GO bonds is generally exempt from state and federal taxation.
- **Revenue bonds:** Revenue bonds are payable from revenues or user taxes of a specific public undertaking or improvement project and are not an obligation of the state. Common examples are airports or toll roads, where debt is issued to finance the development of the project and principal and interest on the bonds is then repaid from

the revenue generated by the asset. Revenue bonds are generally not backed by the taxing authority of the municipality issuing the bonds. As long as the state owns the undertaking or asset, interest on revenue bonds is exempt from state taxation and is generally exempt from federal taxation.

- **SPRBs:** The Hawaii legislature is authorized to issue bonds to "finance facilities of or for, or to loan the proceeds of such bonds to assist, manufacturing, processing or industrial enterprises, certain not for profit private schools, utilities serving the general public, health care facilities provided to the general public by not for profit corporations, early childhood education and care facilities provided to the general public by not for profit corporations, agricultural enterprises serving important agricultural lands, or low and moderate income government housing programs."[94] SPRBs are not backed by Hawaii's tax revenues but are backed by an interest in the project being financed. Interest received on SPRBs is exempt from state taxation and is generally exempt from federal taxation.

The state constitution requires a majority vote in both houses of the Hawaii state legislature to authorize the issuance of GO bonds and revenue bonds, and a two-thirds vote in both houses to authorize the issuance of SPRBs. GO Bonds may also require voter approval through a bond referendum.

As stated above, SPRBs may be used to finance any "utilities serving the general public." This includes financing investor-owned utilities. Indeed, as of July 1, 2015, $462 million of the nearly $1.4 billion in SPRB debt outstanding was used to finance HEI subsidiary companies HECO, HELCO, and Maui Electric.[95]

Similar to the debt instruments discussed previously, all types of municipal debt instruments will be subject to certain affirmative and restrictive covenants. Affirmative covenants require the issuer to perform certain activities, such as comply with financial reporting requirements or maintain insurance. Restrictive covenants limit the issuer's ability to perform certain activities.

[94] "State Debt." State of Hawaii. March 17, 2016. <http://budget.hawaii.gov/budget/about-budget/state-debt/>

[95] "Special Purpose Revenue Bonds Issued and Outstanding, and Authorized and Unissued July 1, 2015." Director of Finance, State of Hawaii. November 24, 2015. <http://budget.hawaii.gov/wp-content/uploads/2012/11/2015-Indebtedness-Stmt-conformed-sig-11-24-15.pdf>

The most common of these are financial covenants that limit the issuer's ability to incur additional indebtedness based on certain financial ratios, such as a debt service coverage ratio.

3.1.3 Summary

The type of capital raised by a utility will ultimately be determined by the ownership structure selected. Public equity and debt markets, including municipal debt markets, are highly liquid markets and are generally accessible to a variety of issuers at any given point in time. All equity and debt issuances, whether public, private, or municipal, will be subject to market conditions at the time of issuance, which can impact the all-in cost of capital raised, required covenants, or other conditions required under the financing documents. Accessing these markets can initially be time consuming; however, once the entity has successfully raised capital, follow-on issuances are relatively straightforward to execute.

3.2 Other Financing Options Available to Utilities

3.2.1 USDA Rural Utilities Service

The U.S. Department of Agriculture's Rural Utilities Service Electric Program provides low-cost loans and loan guarantees to "finance the construction or improvement of electric distribution, transmission and generation facilities in rural areas." [96] RUS loan products are available to both public and private entities, cooperatives, federally-recognized tribes, and non-profit organizations. Funds may be used to improve electric infrastructure that is located in non-rural areas, as long as the electricity generated serves "qualified rural areas." RUS will typically finance up to 75% of a project's costs; however, financing for electric facilities that serve both rural and non-rural localities is prorated by the percentage of rural areas served. Loan repayment schedules are capped at 35 years and generally cannot exceed the useful life of the financed facility. RUS loan guarantees and standard "Treasury Rate" loan products are structured with fixed interest rates equal to the daily U.S. Treasury curve plus one-eighth of one percent.[97] These

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[96] "Rural Utilities Service." U.S. Department of Agriculture. March 4, 2016. <http://www.rd.usda.gov/about-rd/agencies/rural-utilities-service>

[97] Ibid.

rate terms are often much lower than those offered by comparable non-RUS loan products, which include a higher risk premium and which may vary depending on credit rating or other factors.

RUS also administers a "Cushion of Credit" program that allows borrowers to earn five percent interest per annum on "all payments on RUS notes which are in excess of required payments."[98] This feature is particularly attractive for borrowers with excess funds available in the current low interest rate environment.

3.2.2 National Rural Utilities Cooperative Finance Corporation

The National Rural Utilities Cooperative Finance Corporation is a "member-owned, non-profit financing cooperative charged with raising funds from the capital markets on behalf of electric cooperatives."[99] CFC was formed in 1969 to leverage the combined resources of individual electric cooperatives, in order to achieve more attractive financing options in the private debt markets. Since then, CFC's loan portfolio has grown to over $20 billion.[100] CFC operates as a financing cooperative, owned by its member electric cooperatives. To join CFC, prospective members must be electric cooperatives and pay a one-time $1,000 fee.

CFC provides various loan products, as well as value-added services, to its members. These products include short-term lines of credit as well as long-term loans. Rates may vary based on the risk of the borrower, market conditions, and other factors. Cooperatives that borrow exclusively from CFC may be eligible for lower rates than those that borrow from multiple different lenders. Currently, approximately 115 electric cooperatives borrow solely from CFC. CFC does not require its members to have or maintain a credit rating from any third-party organizations; however CFC does typically require certain loan covenants. These covenants generally include a modified debt service coverage ratio, a minimum 20% equity commitment, and a requirement for annual independent financial audits. CFC provides financing to both

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[98] 7 C.F.R. § 1785.68

[99] "Our History." National Rural Utilities Cooperative Finance Corporation. March 9, 2016. <https://www.nrucfc.coop/content/cfc/about_cfc/overview/the-cfc-story.html>

[100] Ibid.

existing and newly-formed cooperatives, and CFC funding can be used for either maintenance of existing assets, construction of new assets, or the acquisition of third-party assets. In 2002, CFC loan products helped KIUC purchase the assets of Kauai Electric. CFC also provides value-added services to its members, including an annual statistical report of cooperative electric utilities, modeling assistance, and various educational meetings and workshops.

3.3 Valuation Considerations

Should Hawaii decide to further pursue an alternative ownership structure for the Oahu and Hawaii Island utility assets, a detailed financial analysis will be necessary. A crucial component of such an analysis would be an appraisal of the assets to be acquired and financed. Discussed further in Section 4.1.4.4, the purpose of this exercise would be to determine the assets' fair market value (and thus the appropriate price at which HEI should be compensated by the acquiring party). The following section presents an overview of several fundamental appraisal concepts and how existing publicly-available data may potentially fit into the puzzle of triangulating a value for the Hawaii utility systems. While FEP discusses these concepts at a high level below, it is important to note that FEP is not presenting any opinions of value at this time, and this report does not constitute an appraisal.

In estimating the market value of an entity, an appraiser would consider each of the three generally recognized approaches to valuation:

- Income Approach: The income approach considers value in relation to the present worth of future benefits derived from ownership, and is usually measured through either the capitalization of a specific level of income or by discounting a projected cash flow stream to determine the present value of future earnings.
- Cost Approach: Under the cost approach, the value of a particular asset or group of assets is normally determined using three alternative methods for estimating value: Replacement Cost, Reproduction Cost and Historical (or Original) Cost. The logic in using the cost approach for valuation rests on the theory of substitution; that is, a prudent buyer will not pay more for a property than the cost of acquiring a substitute property having like utility (plus an amount for the time of replacing the asset).

- Market Approach: The market approach analyzes recent sales and offering prices of comparable assets to derive an indication of value for the asset being appraised. Under the market approach, a sufficient body of prior transactions must be available for public review to allow useful conclusions to be drawn.

All appraisals would be required to follow the Uniform Standards of Professional Appraisal Practice ("USPAP") as well as Hawaii state law.

3.3.1 Income Approach

To apply the income approach to value the Hawaii utility systems, an appraiser would need to construct a discounted cash flow model to assess their financial performance under the assumption of a third-party, arms-length transaction by willing parties. A thorough income approach would also address going concern value to the current owner. Important drivers of an income approach model include revenue and operating cost forecasts, capital expenditure projections, and the derivation of an appropriate market-based discount rate. This exercise may also require additional document discovery from the incumbent utilities.

3.3.2 Cost Approach

In evaluating the value of a system based on its cost, an appraiser may generally consider either the "reproduction cost new less depreciation" or the "replacement cost new less depreciation" methods. "Original cost" and "original cost less depreciation" (aka "net book value") also provide useful data points for estimating fair market value.

Reproduction cost reflects the cost to build a new system based on identical components as the subject system. The reproduction cost would consider the cost to procure and install these components, regardless of their current functional obsolescence.

Replacement cost analysis, on the other hand, considers the cost of developing and installing a new system of "like utility." The cost to produce this replacement facility would incorporate the additional technical and functional efficiencies and cost reductions that may have occurred since the subject property was originally procured and installed. Generally the replacement cost is the better indicator of value for a system when evaluating a fair market, arms-length transaction.

In both cases an appraiser would reduce the system cost by accumulated physical, functional and economic depreciation of the subject assets, to reflect the respective impacts of obsolescence due to wear and tear, decreased usefulness, and declining competitiveness due to external market factors. The evaluation of physical depreciation is highly dependent on the appraiser's evaluation of the age and remaining useful life of the system. Utility assets are complex systems, and the evaluation of the effective age of the system requires a high level of expertise.

Original cost and original cost less depreciation respectively convey the actual costs paid for an asset, including capitalized expenditures and retirements, and the depreciated accounting "book" cost. According to the NextEra/HEI merger application, HECO's original and book costs as of September 30, 2014 were approximately $5.37 billion and $4.12 billion, while HELCO's original and book costs were $1.35 billion and $879 million, respectively.[101]

Regardless of cost method chosen, in practice an appraiser would likely rely on a utility's continuing property record and accounting records to obtain an inventory and original cost of all of the assets being considered, in addition to physical inspections and surveys of the assets.

3.3.3 Market Approach

The market approach analyzes recent sales and offering prices of comparable entities to derive an indication of value for the entity being appraised. A practitioner of the market approach may calculate and utilize multiple different metrics to derive an appropriate range of valuation estimates. These metrics may include, but are not limited to:

- Sales price / Book Value
- Sales price / Number of Customers
- Sales price / Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA")
- Sales price / kW of Installed Capacity

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[101] "In the Matter of the Application of Hawaiian Electric Company Inc., Hawaii Electric Light Company, Inc., Maui Electric Company, Limited, and NextEra Energy, Inc., for Approval of the Proposed Change of Control and Related Matters: Application Exhibits 1 through 8, Verifications and Certificate of Service." HPUC Docket No. 2015-0022. January 29, 2015.

FEP analyzed recent market transactions of generation, transmission, and distribution utilities, as well as sales of utilities that operated only distribution and/or transmission assets. FEP then calculated a range of several illustrative variables, which could hypothetically be used to construct a market-based valuation estimate for a target utility. These results are displayed in Table 3-2 and Table 3-3.[102]

As shown by these selected market transactions, FEP found a wide range of sales prices for both vertically-integrated and distribution/transmission-only utilities. These differences reflect the uniqueness of each transaction, asset portfolio, and the market and regulatory factors of their given regions. Because no two transactions are identical, the market approach is often of more limited use in deriving an exact fair market value than are either the income or cost methods. Nevertheless, the market approach can provide a useful high level perspective or a "sanity check" on the appraisal process.

[102] Data from SNL Financial and FEP research.

Table 3-2: Comparable Sales Analysis: Generation, Transmission, and Distribution Companies

Buyer	Seller	Year of Sale	Sales Price ($M)	Book Value ($M)	EBITDA ($ 000)	Number of Customers	kW Capacity	Sales Price Per $ Book Value	Sales Price Per EBITDA (2016 $)	Sales Price Per Customer (2016 $)	Sales Price Per kW (2016 $)
Duke Energy Corporation	Progress Energy, Inc.	2012	25,717	14,432	1,933,614	3,100,000	23,000,000	1.8	13.9	8,677	1,169
AES Corporation	DPL Inc.	2011	4,613	1,593	530,257	515,000	3,800,000	2.9	9.3	9,542	1,293
Gaz Métro Limited Partnership	Central Vermont Public Service Corporation	2012	704	407	40,939	160,000	100,300	1.7	18.0	4,603	7,343
Berkshire Hathaway Inc.	NV Energy, Inc.	2013	10,453	6,927	1,148,726	1,300,000	6,138,000	1.5	9.4	8,276	1,753
Wisconsin Energy Corporation	Integrys Energy Group, Inc.	2015	9,073	5,426	955,061	2,100,000	2,816,000	1.7	9.5	4,331	3,230
Exelon Corporation	Constellation Energy Group, Inc.	2012	10,623	10,324	N/A	1,894,200	11,751,000	1.0	N/A	5,866	946
Fortis Inc.	UNS Energy Corporation	2014	4,310	1,974	478,907	563,000	2,240,000	2.2	9.1	7,752	1,948

Average (Mean)................................	1.8	11.5	7,007	2,526
Median..	1.7	9.4	7,752	1,753
Minimum..	1.0	9.1	4,331	946
Maximum..	2.9	18.0	9,542	7,343

Table 3-3: Comparable Sales Analysis: Transmission and Distribution Companies

Buyer	Seller	Year of Sale	Sales Price ($M)	Book Value ($M)	Number of Customers	Sales Price Per $ Book Value	Sales Price Per Customer (2016 $)
American Electric Power (SWEPCO)	Valley Electric Membership Cooperative	2010	102	88	30,500	1.2	3,636
Rappahannock Electric Cooperative and Shenandoah Valley Electric Cooperative	Potomac Edison Company (Allegheny Power)	2010	317	286	102,000	1.1	3,379
Potomac Edison Company	Shenandoah Valley Electric Cooperative	2010	15	9	3,200	1.6	4,926
Lubbock Power & Light	Xcel Energy	2010	88	64	23,921	1.4	3,990
California Pacific Electric Company	Sierra Pacific Power Company (NV Energy)	2011	132	125	47,000	1.1	2,992
Liberty Energy (Algonquin)	Granite State Electric Company (National Grid)	2012	83	72	41,584	1.2	2,088
Jefferson County Public Utility District (JPUD)	Puget Sound Energy	2013	108	47	18,000	2.3	6,196
Pacific Gas & Electric	City of Hercules, California	2014	10	N/A	694	N/A	13,860
Balfour Beatty Infrastructure Partners, L.P.	Upper Peninsula Power Company	2014	299	194	52,000	1.5	5,818
Southern Minnesota Energy Coop	Alliant Energy Corporation	2015	127	N/A	42,000	N/A	3,031
Exelon Corporation	Pepco Holdings, Inc.	2016	12,348	7,860	1,860,000	1.6	6,639

Average (Mean)..........................	1.4	5,141
Median....................................	1.4	3,990
Minimum..................................	1.1	2,088
Maximum..................................	2.3	13,860

4 Potential Steps to Create an Electric Utility

4.1 Process for a Citizen-Owned Electric Utility Acquisition

The process of converting an electric system to municipal or cooperative ownership can be a long and detailed journey. There are several critical steps that need to be taken to accomplish the goal of determining whether or not to move forward with acquisition of all or part of an electric utility system. These steps, outlined below, are not necessarily chronological or all-inclusive. Rather, they are intended to present a general road map of necessary actions and analyses, based on previous municipal acquisitions, or attempted acquisitions, of other electric systems.

After defining the goals that Hawaii would desire to achieve through electric system ownership, it will be necessary to appoint an internal leadership group to oversee subsequent efforts and analysis. This leadership group should commence a high level "Fatal Flaw" analysis to investigate whether any significant barriers may exist to continuation. During or after this process, the leadership team should assemble a team of third-party professionals to conduct more extensive due diligence, which will likely include: detailed technical and financial analyses, legal feasibility and litigation support services, and possibly public relations assistance. The leadership group may then wish to initiate discussions with the incumbent utility regarding asset transactions and/or condemnation proceedings. Depending on the scope of the transaction, there may exist the need for stranded cost proceedings.

The process of defining goals and objectives is described in Section 4.1.1, Section 4.1.2 elaborates on the development of a leadership group and hiring of a professional team, Section 4.1.3 discusses the initial phase of "Fatal Flaw" analyses, more in-depth "Detailed Diligence" is explained in Section 4.1.4., and Section 4.1.5 presents high level estimates of costs and timing for many of the aforementioned processes.

4.1.1 Define the Goals and Objectives of Electric System Ownership

As an initial step towards exploration of an alternative utility ownership structure, Hawaii policymakers and the public should define the goals and objectives that the islands of Oahu and/or Hawaii wish to achieve through owning their electric systems. These may include items such as: local control, lower rates, a revenue source for a municipality, and/or environmental considerations. Lower rates may be possible but are not a given. If municipalization will result in higher rates than the existing electricity provider under similar scenarios, the effort may need to be reconsidered or abandoned. Honesty and openness between policymakers and their constituents is paramount at this stage and indeed at all stages of the acquisition. Because much of the process will take place in the public sphere, there will be heavy scrutiny by stakeholders both for and against the new utility. As will be discussed later, there will be strong headwinds generated by those who wish to thwart the process, and should they find errors or falsehoods in analyses, they will strongly exploit them.

4.1.2 Leadership Group and Professional Team

Another early step will be to appoint a representative or representatives of the owners of the future utility entity. If, for instance, a cooperative utility is envisioned, owner-members of the cooperative should hire either a qualified external manager, or assign a member or members to lead the effort.[103] A municipality may wish to create a new office and hire a dedicated city manager or professional to oversee electric utility-related activities. This leader or team will coordinate both internal and external resources to conduct the evaluations discussed previously.

To conduct aspects of the initial "Fatal Flaw" analysis (discussed below) as well as to conduct more thorough levels of due diligence, it will be important to develop a team of advisors. These advisors will be critical to the analysis, acquisition, and structuring of the utility, and they should be included in negotiations and transition planning. There should be close collaboration between the leader(s) of the utility effort and at least three professional advisory groups.

First, the leader(s) of this effort should retain legal counsel who are knowledgeable and well-versed in Hawaii eminent domain law, utility structure, finance, and labor issues. This person or

[103] It is important to note that several community and business leaders on Hawaii Island have already formed a non-profit cooperative association, the Hawaii Island Energy Cooperative, "to explore and promote a comprehensive approach to develop an integrated, renewable and sustainable energy strategy for the Big Island of Hawaii." This organization is already examining the feasibility of a cooperative electric utility ownership structure on Hawaii Island.

Hawaii Island Energy Cooperative. <http://www.hiec.coop/>

persons will also advise on the likely threat of lawsuits and provide input to defense attorneys should lawsuits go to court. Outside counsel, or a coordination between inside and outside counsel, is advisable.

Secondly, a dedicated public relations employee or staff is recommended. This person or persons might be hired internally or from an outside firm that specializes in public relations of this type.

Finally, an engineering and financial valuation team should be engaged. This team will likely be a third-party firm that has preexisting experience in the technical, financial, and operational aspects of electrical utilities. Experience with rate development, integrated resource planning, and municipalization efforts will be beneficial. This firm may be tasked with developing:

- Technical evaluation of the existing system. This initial analysis should be fairly high level but at the same time it needs to identify any serious concerns or flaws that might cause issues in the future.
- Asset valuation and appraisal. After a high level financial feasibility exercise utilizing existing records and published information, a detailed appraisal must be completed if the project appears feasible.
- Customer rate forecast. This will utilize the above valuation to develop scenarios regarding the affordability of the utility. Analysis will entail development of a future capital expenditure budget and identification of project risks.
- Organizational structure of the utility. While this is discussed as a separate item, it is closely related to financial viability personnel costs present ongoing expenses that adds to the revenue requirements of the utility.
- Integrated resource plan. This plan will articulate the supply and demand requirements for the new electric utility over the medium to long-term planning horizon.

Technical evaluation, asset valuation, and financial viability should be analyzed in two phases: an initial high level examination of “fatal flaws” and a more detailed due diligence review sufficient to proceed to financing, regulatory review, potential litigation, and transaction closure.

4.1.3 Fatal Flaw Analyses

Before the leadership group embarks on more detailed analysis, there must first be a high level study of the technical, financial, and legal ability to complete an acquisition. This is necessary to provide a level of confidence that the project will be in the best interest of the citizenry, as well as to determine the level of public support for the effort. The following steps should be taken to analyze whether there exist any potential deal-killers, which could derail an electric utility acquisition.

4.1.3.1 Technical Analysis

This analysis must examine several technical considerations. At minimum, there should be a high to medium level technical analysis of the proposed municipalization to determine what interconnections (if any) must be made, from where power can be purchased, and to whom power must be sold to meet the needs of the planned customers of the utility. At first glance, there do not appear to be many technical barriers to an alternative utility ownership structure in Hawaii, due to size and separateness of each island system. However, this analysis will identify potential pitfalls. Two questions that this technical analysis should definitely address are whether additional generation will be required in the near-term to meet customer demand, and whether a new utility will be able to meet the state's Renewable Portfolio Standards.

4.1.3.2 Rate Feasibility

A separate analysis must be conducted on the cost impact to ratepayers, based on a range of potential acquisition costs, operational costs, and generation alternatives compared to the status quo. This will allow for determination of any significant financial barriers to acquisition. It should be stressed that while there is a mathematical method to developing retail electric rates based on costs, in reality there exist political considerations that will pressure policymakers to restructure rates for the benefit of certain entities. While this high level rate analysis will evaluate the impacts of a variety of cost and revenue scenarios on retail rate allocations, at a later date these allocations may change. At this high level, it is most important that overall projected revenues are accurately depicted.

4.1.3.3 Ability to Finance

Based on the rate feasibility analysis discussed above, a range of projected income statement projections must be developed to ascertain the ability to finance acquisition costs and to service the debt associated with that financing. This analysis must include a debt service coverage test, as well as an evaluation of the ability to finance on-going capital expenditures. There must also be consideration of loss of revenue and the possibility of increased capital or operational costs. The foregoing analysis must articulate potential risk factors that could impact the financial stability of a new entity. These risks may include reduced customer demand due to increased levels of distributed solar generation, storm-related damages, higher levels of mandated renewables on an abbreviated timeline, and increased costs of fuel, among other things. Throughout the analysis, decision-makers must consider how the existing power supplier might function under these same constraints.

4.1.3.4 Legal Feasibility

It will be important to understand any legal hurdles or barriers to a potential acquisition. These may relate to local condemnation rules, state laws regarding municipal ownership of electrical utilities, and/or the requirements for regulatory approval of an acquisition or merger. There may be requirements for public referendum on acquisition and/or financing decisions. There may be issues in the state constitution that hinder the implementation of public power.

4.1.3.5 Political Support

The political will of the affected towns, cities, and islands cannot be overemphasized in the potential acquisition. There may be stakeholders who oppose the acquisition for various reasons, ranging from core beliefs about the role of government to reliability and monetary concerns. There must be a strong public relations presence, and statements regarding the acquisition must be backed by factual information. Employment and labor issues may become highly politicized. Questions regarding job functions, salaries, and benefits will impact the rate analysis and financial aspects of the proposed acquisition. Current electric system employees may face anxiety regarding future employment opportunities. These questions will impact stakeholder sentiment among employees and their families. Early in the acquisition process, there should be agreements concerning the treatment of current and future employees to prevent these issues from becoming overly politicized.

4.1.3.6 Citizen Support

To reiterate, it is critical to understand the community support for any potential electric system acquisition. The processes of utility formation and acquisition usually span multiple years, and it is very important that the community is supportive of the strategy for the long term. The political support mentioned in the previous paragraph considers elected officials as the final policymaking group. However, if enough local citizens believe that they will be harmed from either a cost or service standpoint, these concerns will be reflected through the public comment and electoral processes, and a loss of political will to move forward may result.

After conducting the high level analyses listed above, if the leadership group does not find any major "fatal flaws" in the technical, financial, legal, or political ability to move forward, they should progress to a "Detailed Diligence" phase. The next steps associated with this phase are described in the following section.

4.1.4 Detailed Diligence

The following steps should be taken after the initial "Fatal Flaw" analyses listed above, should it be determined to move forward with an alternative electric utility ownership structure. These analyses should be conducted by the professional team (or their representatives and colleagues) and should be detailed enough to demonstrate to policymakers whether acquisition will be of benefit to municipalities and the citizenry.

4.1.4.1 Detailed Legal Analysis

Counsel from the external professional team should conduct a more detailed legal analysis to determine the legal feasibility of the proposed acquisition. This analysis should identify which of the proceedings listed in Section 5.2 might be necessary, as well as any others not listed in this report. It should also attempt to estimate costs, timing, and strategies for navigating through each proceeding, as well as how the professional team's legal counsel (if external) will interface with any internal legal resources.

4.1.4.2 Inventory of Assets and Separation Analysis

The attainment of fairly detailed asset information will be necessary. This information may or may not be accessible to the general public. If an inventory of assets does exist and is accessible, a random sample should be taken in the field to gain a view on the accuracy and condition of distribution assets such as poles, cables, and transformers. Generation and substation facilities should all be visited to ascertain their conditions, with the goal of calculating a value for these properties. If asset information is not available or not accessible, more detailed field inventory must be gathered to provide the information necessary to appraise the system. The inventory should also consider real property, equipment (such as vehicles, diggers, pole-setting trucks, etc.), buildings, and any other infrastructure slated for acquisition. An engineering advisor should also determine what steps (if any) will be necessary to separate and/or re-engineer the system to accommodate an alternative utility ownership structure.

4.1.4.3 Future Capital Expenditures Budget

A professional team should work with the municipal or cooperative entity to develop a long range projection of future capital expenditures, which will be required to operate and maintain the utility. Based on a review of asset conditions and other variables, such as future development of generation or inter-island electrical interconnections, a high level capital expenditures budget should be developed to be included in the aforementioned appraisal. It is at this point that technical analysis of the existing system becomes extremely important. Often, utilities may defer capital expenditures and maintenance for various reasons. Deferment of these expenditures must be identified to provide an accurate baseline and future cost estimate for utility ownership. In addition, considerable thought must be given to state mandates for renewable energy.

4.1.4.4 Appraisal and Valuation

To develop and support a fair market price for the proposed transaction, a detailed appraisal of asset values should be developed using income, cost, and/or market-based valuation models (see Section 3.3 for more discussion of these methods). This appraisal will utilize the inventory of assets (Section 4.1.4.2) as well as the capital expenditures budget (Section 4.1.4.3).

Any appraisal should adhere to the Uniform Standards of Professional Appraisal Practice as well as any Jurisdictional Exceptions for the state and local jurisdictions. The appraisal should include a third-party view as well as a going-concern valuation.

4.1.4.5 Model Customer Rates and Compare to the Status Quo

The purpose of this study will be to allocate the costs of operations to different rate classes (e.g. residential, commercial, industrial). It will be important to also compare the projected rates to the rates associated with the existing ownership structure. As mentioned previously, political factors and prior experiences with HPUC hearings should be considered when projecting rates.

4.1.4.6 Develop a Management Structure and Staffing Plan for the Utility

It is important to develop an organizational structure for the proposed utility. While this structure admittedly may change after the organization is formed and becomes an independent entity, this analysis will help to identify the costs associated with management and staffing, and will also allow the newly formed utility to develop a transition plan for employees of the acquired utility.

4.1.4.7 Development of a Proposed Governance Structure

The development of a proposed governance structure should be based on the desires of elected officials of the entity or entities that own, or are projected to own, the newly formed utility. As this exercise will define the composition and structure of the governing authority for the utility, it will probably be contentious. The governing authority could be an elected or appointed board, a city council, or other elected/appointed group. The decision to form a cooperative or municipal utility may impact how this governing authority must be selected. The job duties of this governing board might include the hiring and evaluation of a utility general manager, as well as the approval of rates, budgets, and utility policies.

4.1.4.8 Conduct an Integrated Resource Plan for the 5 and 10-Year Planning Horizon

The integrated resource plan is a common study used by regulated utilities to determine:

- Load growth projections by area;
- Transmission constraints and necessary additions;
- Size, location, and types of future generation assets;
- Potential for demand side management and energy efficiency; and
- State and/or local requirements for the acquisition and development of sustainable energy, along with considerations of its costs.

4.1.4.9 Approval of Financing

During the Detailed Diligence process, should the acquisition appear likely to proceed, the leadership group should bring a financial advisor into the professional team to pursue options for financing the acquisition (e.g. issuance of municipal debt, USDA RUS loans, CFC loans, or other products). Once a negotiated purchase and sale agreement has been executed, or a condemnation proceeding has determined fair market value of the acquired assets (see Section 5.2 for discussion of negotiations and condemnation proceeding), the attainment of approved financing will be necessary for deal closure. Early approval of financing may help expedite other regulatory proceedings.

4.1.5 Estimated Time and Cost Requirements

At the present (very preliminary) stage of utility ownership exploration, it is extremely difficult to accurately forecast future timing and cost requirements for the aforementioned activities and analyses. As evidenced by the cities of Boulder, Colorado (see Section 2.6) and Las Cruces, New Mexico (see Section 4.3), a contentious transaction process – rather than a friendly acquisition from a willing seller – can result in drastically higher costs and much more lengthy negotiations, regulatory proceedings, and litigation. Numerous other factors may conspire to increase costs and timing, including, but certainly not limited to:

- Incomplete or inaccurate characterization of fatal flaws during preliminary investigations;
- Difficulties or delays in assembling a leadership group and/or external professional team;
- Lack of political support among policymakers and/or constituents;
- Lengthy negotiations between buyer and seller;
- Delays in legislative or regulatory proceedings;
- The presence of stranded cost liabilities;
- Complicated technical requirements around system separation;
- Changes in financing terms; and
- Unforeseen or longer-than-anticipated litigation.

With the above caveats, FEP has provided time estimates for the various recommended steps and analyses, assuming that the transaction is friendly and non-contentious, without any fatal flaws or unforeseen cost overruns. These are shown in Table 4-1 alongside estimated costs for services provided by an external professional team. Of critical note is the fact that these projections exclude the costs of all internal (municipal or cooperative) resources that may work in collaboration with the professional team. These internal costs will be non-trivial and may easily exceed professional fees. Internal costs may include both explicitly-budgeted labor and materials associated with a dedicated utility exploration/management team, as well as “hidden” costs associated with the part-time (or full-time) reallocation of existing personnel resources to utility-related activities. The costs below also ignore any external legal fees beyond the “Fatal Flaw” and “Detailed Diligence” legal analyses. Legal fees associated with activities presented in the “Negotiations and Legal/Regulatory Proceedings” discussion (Section 5.2) may be significant.

After the definition of goals and the appointment of leadership and professionals, the multiple fatal flaw analyses could be mostly conducted at the same time, with the exception of the rate feasibility study, which is prerequisite to analyzing the ability to finance the acquisition. In a highly expeditious transaction, many of the more detailed analyses could also be conducted in parallel. In the best-case scenario, timing from start to deal closure could be as short as a year, whereas under less favorable conditions the process could last a half-decade or more. The level of contention surrounding the transaction will likely heavily influence its overall timing and cost requirements.

Table 4-1: Preliminary Cost and Timing Estimates for Various Steps of a Non-Contentious Transaction

Analysis / Activity	Report Section(s)	Preliminary Cost Estimate	Preliminary Time Estimate
Definition of Goals/Objectives	4.1.1	Internal costs only	60 – 90 days
Appoint Leadership Group and Professional Team	4.1.2	Internal costs only	30 – 90 days
Fatal Flaw Analyses	4.1.3	\$90K – \$300K	60 – 120 days
Detailed Legal Analysis	4.1.4.1	\$80K – \$300K excluding regulatory/litigation support	30 – 90 days
Inventory of Assets and Separation Analysis	4.1.4.2	Validate existing inventories: \$90K – \$300K Develop new inventories: \$300K+ per island	60 – 120 days 120+ days
Appraisal and Valuation including Future Capital Expenditures Budget	4.1.4.4, 4.1.4.3	\$90K – \$300K per island	60 – 120 days
Model Customer Rates and Compare to Status Quo	4.1.4.5	\$30K – \$100K	60 – 90 days
Management/Staffing and Governance Plans	4.1.4.6, 4.1.4.7	Mostly internal costs with possibility of professional fees	30 – 90 days
Integrated Resource Plan for 5-10 Years	4.1.4.8	\$60K – \$150K per island	60 – 120 days
Approval of Financing	4.1.4.9	Likely financing fees from 1% to 3% of transaction value	60 – 180 days
Negotiations and Legal/Regulatory Proceedings	5.2	Dependent upon multiple factors	TBD

4.2 Utility Operations, Maintenance, and Overhead Requirements

A municipal or cooperative utility would likely be structured similarly to other, investor-owned utility organizations. This organization may be led by an executive leadership team or CEO, who oversees a staff of technical, administrative and customer relationship specialists. To the extent that these roles already exist in county or state government, a small municipal utility may be able to leverage some economies of scale. A larger utility, or a non-public utility, may need to hire and direct all staff functions.

In the following analysis, FEP presents a rough approximation of possible operating expenses and staffing requirements for a hypothetical utility system, which would operate the generation, transmission, and distribution assets currently owned by HECO and HELCO, and which would serve the incumbent utilities' Oahu and Hawaii Island service territories.

4.2.1 Analysis of Existing HECO and HELCO Systems

To estimate the operational requirements of a hypothetical utility, FEP first examined publicly-available data from HEI's annual reports and website. FEP found the following breakdown of active generation assets, owned by HECO on December 31, 2015, as shown in Table 4-2.

Table 4-2: HECO-Owned Active Generation Facilities[104,105]

Generation Facility	Capacity (MW)	Fuel Type	Firm or Variable?
Waiau	500	Oil	Firm
Kahe	650	Oil	Firm
Campbell Industrial Park	120	Biofuel	Firm
Total	**1,270**		

According to HEI records, HECO purchases an additional 457 MW of firm capacity and energy from three independently-owned fossil fuel and waste-burning facilities, as well as the energy from 138 MW of mostly wind and solar as-available capacity and energy resources. Additionally, approximately 332 MW of customer-sited solar power is connected to the HECO system.

HELCO's active generation assets on Hawaii Island are listed in Table 4-3.

[104] "Power Facts." Hawaiian Electric Company, Inc. March 2016. <https://www.hawaiianelectric.com/Documents/about_us/company_facts/power_facts_2016.pdf >

[105] Note: HECO also owns the 113MW oil-fired Honolulu Power Plant, which appears to have been deactivated in January 2014.

Table 4-3: HELCO-Owned Active Generation Facilities[106,107]

Generation Facility	Capacity (MW)	Fuel Type	Firm or Variable?
Hill	35.5	Oil	Firm
Puna	38	Oil	Firm
Keahole	79.8	Oil	Firm
Kanoelehua	21	Oil	Firm
Waimea	7.5	Oil	Firm
Dispersed Generation	2.5	Oil	Firm
Waiau Hydroelectric	1.1	Water	Variable
Puʻuʻeo Hydroelectric	3.2	Water	Variable
Total	**188.6**		

In addition to these utility-owned assets, HELCO procures approximately 95 MW of capacity and energy from firm petroleum-fired and geothermal generation, and the energy from approximately 43 MW of independently-produced variable wind and hydroelectric resources. Additionally, approximately 70 MW of customer-sited solar power is connected to the HELCO system.

For the purposes of this analysis and report, FEP only considers the working assets owned and operated by HEI and its subsidiaries. Adding Maui Electric's owned generation capacity of 274.1 MW to the above values in Table 4-2 and Table 4-3 brings HEI's total owned generation capacity to nearly 1,733 MW. HECO and HELCO generation assets comprise approximately 84% of this total.

HECO and HELCO operating expenses accounted for around 84% of HEI's total. HEI reported total 2015 operating expenditures of approximately $413 million, excluding fuel, purchased power, taxes, interest, and depreciation. Of this amount, approximately $285 million was attributable to HECO and $63 million was attributable to HELCO.[108] While these historical financial data may

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106 "Power Facts." Hawaiian Electric Company, Inc. March 2016. <https://www.hawaiianelectric.com/Documents/about_us/company_facts/power_facts_2016.pdf >

107 Note: HELCO also owns the 15.2MW oil-fired Shipman Steam Plant, which appears to have been deactivated in 2012.

108 "2015 Annual Report to Shareholders." Hawaiian Electric Industries, Inc. 2016. p. 149.

provide some indication of future O&M expense requirements for a new utility, FEP notes that actual O&M expenses may vary widely depending upon staffing requirements, market forces, different overhead requirements, different economies of scale, and other factors yet to be determined.

4.2.2 Utility Organizational Structure

A typical public or cooperative utility would contain the following functional departments, which are summarized in the following paragraphs:

- Chief Executive Officer ("CEO")
- Operations and Maintenance
- Engineering and Planning
- Power Supply
- Administrative Services
- Legal

The utility chief executive officer and his or her office would be ultimately responsible for running the organization, developing and approving strategic goals and objectives, and overseeing the managers of each other department. For a utility the size of the combined HECO and HELCO, the CEO's annual salary could easily exceed $300,000. Adding department manager salaries of around $250,000 could result in a total budget for executive team salaries in exceedance of $1.5 million. With additional benefit costs of 40%, the annual price for the upper level management team may exceed $2.1 million. While the upper level management group is somewhat easily quantifiable, the rest of the organization is more difficult at our present level of knowledge of the utility. While upper level management will ultimately determine the organizational structure of any newly-formed utility, FEP enumerates many of the proposed roles and functions for each department of a transmission, distribution and generation utility below.

<u>Operations and Maintenance</u>

- Transmission
- Distribution
- Substations

- Dispatch and trouble center
- Meter reading

Engineering and Planning

- Transmission engineering
- Distribution engineering
- Substation engineering
- Planning

Power Supply

- Generation engineering[109]
- Generation operators
- Technicians
- Generation dispatch and control
- Fuel purchasing and supply

Administrative Services

- Finance
- Accounting
- Customer service and billing
- Budgeting
- Information technology
- Human resources
- Janitorial services
- Public relations
- Purchasing

To reiterate, the CEO and managers will decide on the final makeup of the organization. For instance Legal and Human Resources functions often report directly to the CEO, but Legal sometimes reports to a Utilities Board or is contracted outside of the organization.

[109] Note that the engineering required by the generation effort in a varied and large utility might best report directly to the manager of Power Supply, as opposed to a separate Engineering and Planning department.

Without additional data regarding the proposed utility system, it is impossible at this juncture to provide a detailed estimate of the personnel requirements for each utility department. For example, Operations and Maintenance staffing requirements will be determined by factors such as the number of miles of transmission and distribution lines, their current conditions, the percentage of underground vs. overhead lines, number and configuration of substations, and other variables. Power Supply personnel requirements will be influenced by the type, size, and condition of generation facilities. If one of the newly-formed utility's primary goals is to own more solar, wind and/or other renewable forms of generation, different types of operators and technicians may be necessary than those required for HECO and HELCO's existing fossil fuel-fired fleet. While these renewables may be purchased via long-term contracts from independent power producers, the new utility may need to devote resources to the contracting and procurement of third-party power. To the extent that new facilities are required, resources may need to assist with construction planning, permitting, and commissioning of such facilities, while dealing with the potential decommissioning of some existing generation facilities.

In Table 4-4, FEP presents hypothetical allocations of O&M labor expenses by operating division. FEP has assumed that 45% of costs are labor-related salaries and benefits. The remaining 55% of non-labor O&M costs are expected to fund non-capitalized maintenance materials, vehicles and vehicle fuel, as well as items such as advertising, publications, insurance, and business-related employee travel.

Table 4-4: O&M Budget Allocations for a Hypothetical Utility

Budget Item	Percentage
Hypothetical Annual O&M Budget	
Non-Labor	55%
Labor	45%
Hypothetical Labor Budget by Department	
Operations and Maintenance	36%
Engineering and Planning	17%
Power Supply	40%
Administrative Service	7%

FEP stresses that these allocations are preliminary and are meant only to provide a rough approximation of how a hypothetical municipal or cooperative utility might be structured and funded. They do not represent FEP's final staffing estimates or cost forecasts for any newly-formed utility in Hawaii, nor are they intended to reflect HEI's current corporate structure.

4.2.3 Transmission and Distribution-Only Utility

As discussed in Section 2.5.3, should Hawaii pursue the acquisition of only the transmission and distribution utility assets on the islands of Oahu and Hawaii, non-power procurement operating costs and staffing requirements would decline, while there may exist a potential liability for stranded costs.

In the above analysis, instead of operating generation facilities, the Power Supply department of the hypothetical utility would be refashioned into a Power Purchasing department. This would oversee the execution of medium-term and long-term contracts, as well as short-term scheduling and dispatch. FEP estimates that a Power Purchasing department could cost approximately $7 million annually and employ up to 50 staff. No changes in the other departments are envisioned at this level of analysis.

A utility without generation would cost less to maintain and operate due to large reductions in labor and other operating and maintenance expenses. Ownership of generation necessitates higher fixed costs for a utility and increased risks due to increased regulatory requirements, safety issues, and other factors. However, these generation costs and risks will not simply go away but rather will be reflected in the price of purchased power. Included in any power purchases from investor-owned, third-party generation will also be a rate-of-return that will go to investors rather than be given to local government as a PILOT or other transfer to general funds.

4.3 CASE STUDY: City of Las Cruces, New Mexico[110]

The following case study highlights the experiences of the City of Las Cruces, New Mexico, during a municipalization attempt that ultimately did not succeed. It highlights many of the processes described earlier in this section, as well as challenges and pitfalls to avoid, with the intention that future entities pursuing municipalization might learn from the experiences of Las Cruces.

In the late 1980s, there was a move by the cities of Albuquerque and Las Cruces, New Mexico to evaluate the possibility of municipalizing their electric systems. The two municipalities, while separate, were in close communication with each other. At the time, Albuquerque was served by Public Service Company of New Mexico ("PNM") while the City of Las Cruces was served by Texas-based El Paso Electric ("EPE").

For various reasons, the task force in Albuquerque disbanded and the effort to municipalize the electric system stopped. While there was no fatal flaw discovered by the city's effort, the city's existing electric rates were not unreasonable to most constituents, and PNM had a powerful political presence in Albuquerque, where its headquarters was located. However, Las Cruces elected to continue to work toward the goal of developing a municipal utility. The driving force behind Las Cruces' desire to municipalize was the belief that EPE's rates were too high and that a city-owned utility could lower these rates by as much as 20%. The concept was that Las Cruces Joint Utilities might be able to procure wholesale power from a lower-cost provider, such as Southwestern Public Service Company or Federal hydropower projects. If so, it might be able to provide lower rates to citizens even when the costs of acquiring the electric system from EPE were factored in.

[110] Note: this section draws heavily upon the writings of Robert Monday, former Utilities Manager for Las Cruces Joint Utilities from 1996 to 2001. Mr. Monday is currently an FEP employee.

4.3.1 Steering Committee

Because Las Cruces is a single city with a home rule charter the initial task force group morphed into a steering committee that was made up of the City Council, the City Manager, and the Assistant City Manager. Because of oversights within this group, which strongly favored municipalization, no search for any type of fatal flaw was initially conducted. If there were concerns voiced at the outset of the municipalization process, they were likely ignored or overridden by the majority of the group. The City Council passed an ordinance forming a municipal electric utility in 1991.[111]

In the late 1980s or early 1990s a professional team was developed, initially consisting of an engineering firm and a legal firm. Additional engineering expertise was contracted to develop a severance plan, and a local attorney from Albuquerque was utilized to provide legal advice regarding New Mexico law. The professional team was joined by an electrical engineer, the manager of the City's finance department, and City attorneys who provided support to the City Council. Public relations were handled by in-house staff, who were trained and knowledgeable in that field. While the Assistant City Manager was probably the driving force and the de facto overseer of the professional team, the team was never formally organized, and communication struggles occasionally ensued.

4.3.2 Financial Feasibility

The engineering firm provided a judicious financial feasibility study that contained income statement pro-formas and compared various costs, revenues, and payback schedules in order to either validate or invalidate the project. Based on acquisition cost considerations (which included estimated severance costs, stranded costs, and purchase of inventory), Las Cruces held a bond election in 1994 and proceeded to issue revenue bonds totaling $72.5 million.[112] As time progressed, it became evident that Las Cruces would need to incur more debt in order to close its proposed acquisition. The City then issued around $36 million in general obligation bonds and

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111 Daniel, David and Douglas Gegax. "A Cautionary Tale on Municipalization." Forum for Applied Research and Public Policy 15(2). 2000. pp. 49-53.

112 Ibid.

also borrowed from a City fund, which had been designated for vehicle acquisition. These borrowings were to be paid back to the general fund from electric revenues when the utility started selling power.

The engineering firm subcontracted a utility appraiser who provided an estimated base system valuation of $42 million, using three types of appraisal methodologies.[113] Should construction of a new substation be required, these costs were expected to increase by approximately $6 to $8 million. In 1998, an administrative law judge at FERC ruled that stranded cost owed to EPE would be about $30 million, based on a 1998 transaction date.[114]

4.3.3 Legal Considerations

Had a fatal flaw analysis been conducted, Las Cruces may have discovered that potential sources of wholesale power purchases were mostly limited to EPE, PNM, or the United States Bureau of Reclamation.

Another legal roadblock appeared when it was determined that state legislative action would be necessary for municipalization of an electric utility to move forward. A concerted effort was made at the state level to submit and approve legislation enabling Las Cruces to municipalize the electric system. A bill providing for this was submitted and approved at the 1997 New Mexico legislative session.

A third challenge arose related to the City's initial separation plan, which – rather than physically sever the City from the surrounding grid – had proposed to install meters to monitor electric flows between the planned City grid and the outside EPE grid. This plan was ultimately rejected.

Throughout the process, EPE's thorough legal team challenged the proposed acquisition and argued that customer rates would increase under municipal ownership.

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[113] Ibid. Also note that one consulting firm hired by EPE appraised the system at $200 million.

[114] "Initial Decision on Recovery of Stranded Costs." FERC Docket No. SC97-2-000. June 25, 1998.

4.3.4 Power Supply Issues

In 1994, a power supply contract was negotiated with Southwestern Public Service Company and approved by the City. This contract would provide Las Cruces with a reliable source of power for a period of 15 years from the date of the utility acquisition. However, there was no reliable way to get power from the contractor's power plants to Las Cruces due to limitations related to transmission providers in the area. In 1996, FERC's Order 888 mandated open access transmission wheeling of purchased power with stipulations that included stranded cost and opportunity costs. This action gave Las Cruces the leverage it needed to buy wholesale power and have it delivered.

With a power supply agreement in hand and a way to move some power over transmission lines, Las Cruces elected to build a substation west of the City to supply power to a growing group of industrial customers. With this action, the City was finally in the electric utility business, albeit one significantly reduced from its initial vision.

4.3.5 Summary

In the end, the municipalization effort failed. Several cases before the district court, state regulatory bodies, and the FERC threatened to derail the municipalization effort and made its continuation long and costly. While most City residents were ambivalent, there was a vocal group that were against the effort. The City Manager and Assistant City Manager, who were strongly in favor of the project from the start, left office, as did many of the original City Council members. By the end, it had become apparent that retail rates would not be reduced by 20% under municipal ownership, and uncertainty existed around whether there would be any rate benefits at all.

At a meeting in year 2000, the City's consulting engineer, City staff, and EPE reached a compromise for the City to end its municipalization effort if EPE paid the bill for the City expenses already incurred, including purchase and control of the City-owned substation. The City Council and EPE's Board of Directors approved the agreement, and the City recovered approximately $21 million of its expenses. By 2001, the municipalization effort had ended, the City was officially out of the electric business, and both Las Cruces and EPE turned their focus to other issues. EPE continues to serve Las Cruces.

5 Regulatory and Legislative Overview

5.1 Review of Critical Policies

FEP has conducted a high level review of several regulatory policies that have the potential to impact the timing, cost, and/or desirability of an alternative utility structure. Should Hawaii move forward in pursuing utility ownership, it is highly recommended that a detailed legal review be conducted to more thoroughly understand the potential impacts of these and other laws and regulations.

5.1.1 Renewable Portfolio Standards

In 2015, the State of Hawaii passed updated legislation (House Bill 623) regarding its RPS. The updated legislation requires 100% of energy sales in the state to come from renewable resources by 2045.[115] The bill includes interim requirements of:

- 30% by year-end 2020
- 40% by year end 2030
- 70% by year-end 2040
- 100% by year-end 2045

The House has also passed, and has sent to the Senate, House Bill 2291, which requires RPS standards be measured on electric generation output instead of electric sales. The bill's intent is to increase the value of non-utility generated renewable energy (i.e. rooftop solar). Legislators are also discussing the possibility of applying renewable standards to automobiles, replacing all fossil-fueled vehicles with electric or hydrogen fuel cell vehicles by 2045.

Ultimately, the entity that owns and operates the electric generation assets in the State will be held to Hawaii's RPS standards, regardless of ownership structure.

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115 "Hawaii and Vermont set high renewable portfolio standard targets." U.S. Energy Information Administration. June 29, 2015. <https://www.eia.gov/todayinenergy/detail.cfm?id=21852>

5.1.2 Eminent Domain Law

Rights of eminent domain in Hawaii are governed by the Hawaii Revised Statutes Chapter 101. HRS §101-4 specifically grants the right of eminent domain to "public utilities and others", which includes entities engaged in the production and delivery of power. Eminent domain rights can be exercised through either condemnation of the real property for the benefit of public use or through an agreement to acquire the real property through voluntary action. The HRS define the process and procedures to exercise eminent domain rights. The court system is required to give priority to eminent domain cases to ensure expeditious adjudication of the action.

As the HRS are currently drafted, only a government or municipal entity has the right to exercise eminent domain via condemnation. It is likely that a cooperative structure would require a voluntary transaction or special authority from the state legislature to effect a transaction using Hawaii's eminent domain laws. FEP recommends consulting a legal advisor who specializes in eminent domain issues to conduct full due diligence regarding the ability to exercise eminent domain.

5.1.3 Certificate of Public Convenience and Necessity

Public utilities, defined in the HRS §269-1, are required to obtain a certificate of public convenience and necessity from the Hawaii Public Utilities Commission. HRS §269-7.5 specifically addresses the requirements for such certificates to be granted and the information required to be submitted in the application.[116] The statute specifically states that a certificate will be issued to any qualified applicant "…if it is found that the applicant is fit, willing, and able properly to perform the service proposed and to conform to the terms, conditions, and rules adopted by the commission, and that the proposed service is, or will be, required by the present or future public convenience and necessity…"

The statute also grants an exception to public utilities that hold a "…franchise or charter enacted or granted by the legislative or executive authority of the State or its predecessor governments,

[116] Hawaii Revised Statutes §269

or that has a bona fide operation as a public utility heretofore recognized by the commission…" Such utilities are not required to obtain a certificate under these guidelines.

An initial review of this statute and the associated requirements indicates that any resulting corporate structure would likely be eligible to receive the necessary certificates to operate a public utility so long as the PUC finds the entity fit to operate the assets to the public's benefit. However, FEP recommends consulting a legal advisor once the structure has been selected to ensure full compliance with the statute.

5.2 Negotiations and Legal/Regulatory Proceedings

Throughout the stages described in Section 4.1, and to complete the transition to municipal or cooperative ownership, the leadership group will need to engage in negotiations and several legal and/or regulatory proceedings. It will be critical to consult a legal professional to determine the appropriate timing, strategies, and costs associated with these engagements. While FEP in no way purports to provide legal advice, it has outlined potential proceedings, some of which Hawaii may or may not face, in the following subsections.

5.2.1 Formation of an Electric Utility

Before the transfer of franchise agreements and assets can occur, the leadership group and their constituents must transition from an exploratory phase to actually forming and incorporating an electric utility. The legal advisor on the professional team should be able to guide this process, which may involve filings with the HPUC and/or county/state legislative action.[117] Once the new utility is formed, it will likely not own any physical assets but will presumably have the legal authority to seek to acquire them.

5.2.2 Negotiations with Incumbent Utilities

At some point in the process, most likely during or after the Detailed Diligence steps, the leadership group will want to approach HEI about the purchase of some of its HECO and/or HELCO assets. These negotiations will probably focus on whether a friendly acquisition can occur

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[117] In the case of the City of Boulder, CO (see case study in Section 2.6), the municipality had to first seek voter approval via referendum to grant City Council the authority to create a municipal electric utility.

and for what price. Negotiations may be contentious with divergent viewpoints between the leadership group and the incumbent utilities on acquisition costs, stranded costs and the technical requirements of separation. Confidentiality agreements may be necessary to facilitate the sharing of confidential business information relevant to valuations. If a friendly purchase and sale agreement is unable to be reached, the leadership group may need to seek asset condemnation via eminent domain.

5.2.3 Condemnation Proceedings

Should negotiations with the incumbent utilities fail, the counties or state may have the right to condemn electric assets via eminent domain law (which is discussed briefly in Section 5.1.2). Again, the leadership group should consult a legal professional who can advise on such an action.

5.2.4 Transfer of Franchise(s)

Currently, the incumbent investor-owned electric utilities in Hawaii hold franchises, which allow them to produce and sell electric power.[118] Presumably a newly-formed electric utility would need to be assigned these franchises or obtain a certificate of public convenience and necessity in order to legally operate as an electric provider in Hawaii. FEP recommends the consultation of a legal professional to explore this legal and regulatory issue further.

5.2.5 Stranded Cost Proceeding

In FERC-regulated jurisdictions, the federal agency may oversee a proceeding, which is separate from a condemnation proceeding, to determine the stranded costs owed to the incumbent utility. In Hawaii, the HPUC might oversee a similar proceeding should stranded costs be relevant to the proposed transaction.

[118] See, "Applicants' Response to LOL-IR-38." Hawaiian Electric Companies. HPUC Docket No. 2015-0022.