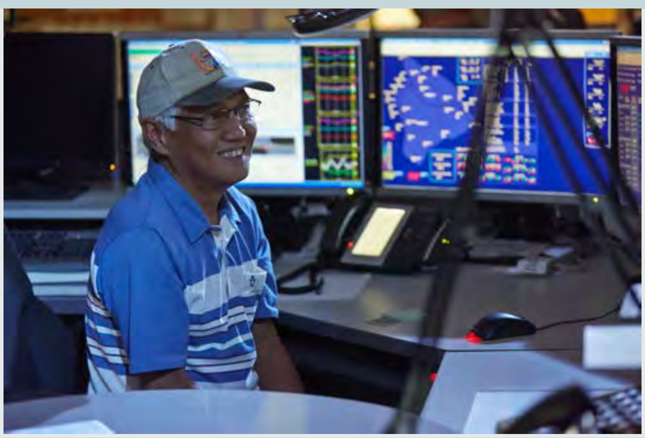
Power Supply Improvement Plan Update Interim Status Report

The current status of our ongoing analysis and planning to address Commission Order No. 33320

February 16, 2016




Hawaiian Electric
Maui Electric
Hawai'i Electric Light

Preface

The Hawaiian Electric Companies respectfully submit this PSIP Update Interim Status Report to comply with Order No. 33320 issued by the Hawai‘i Public Utilities Commission on November 4, 2015 in Docket No. 2014-0183.

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Executive Summary

A DYNAMIC ENERGY ENVIRONMENT

As the only state in the nation with a 100% Renewable Portfolio Standard (RPS) and levels of distributed generation twenty times the national average, Hawai'i's clean energy leadership is indisputable. And while there are many views on the best path to achieve our 100% RPS goal, there is notable unity in Hawai'i in recognizing the critical importance of addressing the negative economic, environmental and energy security impacts of our state's dependence on imported petroleum oil.

Today, the energy planning to do just that is taking place in an environment that is more dynamic than ever. In the eighteen months since our Companies filed the 2014 Power Supply Improvement Plans (PSIPs), much has already changed. Consider just a few of the many significant developments that have transpired over this relatively short period:

1. Passage of Act 97, which extended a 40% RPS requirement in 2030 to a 100% RPS in 2045.
2. Dramatic decline in the price of fuel oil by more than 75%, creating significant changes and uncertainty in forecasted costs.
3. Hawai'i Public Utilities Commission (Commission) Decision & Order No. 33258 ending the Net Energy Metering (NEM) program for new solar customers and concurrently creating two new replacement programs: grid supply and self supply.
4. Valuable ongoing experience with increasing levels of distributed generation (DG), including the testing and installation of advanced inverters to allow greater amounts of DG and reduce the need for distribution upgrades.

In addition, NextEra Energy and Hawaiian Electric Companies have proposed a merger which is pending before the Commission.

And as with virtually all emerging, maturing, and evolving technologies, we expect breakthrough developments, decreasing prices, increasing implementation, and growing community engagement.

Consider the impact on the environment, on culture, and on the electric grid should electric vehicles replace gas-fueled cars in large numbers. Consider the impact on renewable generation should the cost of energy storage decrease by 70% over the next 15 years (as was predicted in January 2016). Consider the potential impact on renewable energy equipment costs as other jurisdictions demonstrate the same forward-thinking mindset as Hawaiʻi and adopt more progressive goals for transitioning to renewable generation. These possibilities can be difficult to predict, but can provide significant opportunities as well.

PLANNING STATUS OF OUR PSIP UPDATE INTERIM STATUS REPORT

The substantial intervening changes noted above were among the reasons the Commission articulated eight Observations and Concerns with respect to our 2014 PSIPs and asked us to address them. In this PSIP Update Interim Status Report, we have begun to address many of these issues and plan to more fully address those and others in our Updated PSIP to be filed on April 1, 2016.

It is important to note what this PSIP Update Interim Status Report is, and what it is not.

First, and most important, all plans indicate we can achieve our state's 100% RPS by 2045.

This PSIP Update Interim Status Report presents a current snapshot of our progress to date in addressing the Commission's directives. The PSIP Update Interim Status Report is not a complete review of resource options or an as-yet optimized plan. It should be viewed as a status on our planning and updating to date. Evaluation and analysis are ongoing. Over the next month and a half, we will continue our modeling and analysis to develop a preferred resource plan and a five-year action plan for each of our operating utilities.

The status of our responses to the Commission's eight Observations and Concerns is integrated into the following topical discussion.

Stakeholder Input

Consistent with the Commission's directive, on January 15, 2016, most of the Parties in this docket filed reports providing input into the process outlined in Order 33320. In addition, we held a stakeholder conference on December 17, 2015 and participated in a technical conference on January 7, 2016. We've considered the input received and have incorporated it, to the largest extent possible, into our analyses thus far.

Also, we've addressed several key points of feedback from the Parties. Examples include: sharing of resource cost assumptions with the Parties; establishment of an FTP site to facilitate sharing data and other information with the Parties and obtaining their feedback; use of a "decision framework" to establish a clear basis for how plan objectives will be prioritized; and introduction of a "PSIP Optimization process" consisting of iterative cycles for Distributed Energy, Demand Response and Utility-Scale Resources to capture analytical steps in achieving the 100% RPS goal.

We've also proposed two additional technical conferences with the Parties.

Our Proposed PSIP Revision Plan also listed additional organizations that agreed to provide independent technical analyses to help address issues of concern. This PSIP Update Interim Status Report reflects current input from some of those stakeholders, such as the National Renewable Energy Laboratory (NREL), Hawai'i Natural Energy Institute (HNEI) and Electric Power Research Institute (EPRI), as well as from General Electric. We are still working with all of these and other organizations while we continue our analyses for developing our Updated PSIPs.

Objectives of the Resource Planning Decision Framework

In our analyses, we strive to balance on behalf of our customers a cost-effective portfolio of renewable resources, attainment of all RPS milestones, system reliability and security, and environmental compliance to achieve our objectives in both the near-term (five years) and long-term (30 years).

Additional Key Resources to be Included

While we've made substantial progress on the PSIP Update, as part of our status report, it's important to highlight in the sections that follow some key resources that have not yet been fully incorporated into our planning.

The Critical Role of Distributed Energy Resources (DER)

Hawai'i is the frontrunner in integrating DER from customer-owned photovoltaics into the power grid—a position we fully intend to maintain. DER will play a critical role in attaining a 100% RPS. Customer adoption rates have a big effect on the amount of DER that can be incorporated into our generation mix. At this point in the PSIP Update analytical process, we have developed an initial market-driven DER program based on initial case assumptions. We are doing further analysis and are developing programs to enhance this adoption rate—programs that optimize and provide the most benefits for our customers and grid services in conjunction with other renewable resources in our future portfolio.

The Potential of Demand Response (DR)

With the continued growth of DER, our customers play an increasingly important role in energy supply. We firmly believe that demand response, as an important and unique category of DER, is an integral component of our system of resources for grid operations. Our goal is to implement DR programs that appeal to residential and commercial customers, and that provide cost-efficient resources for the integration of renewable energy and the operation of our electric grids. Thus far in our PSIP Update process, we have developed an initial DR program for O'ahu leveraging models and methodologies developed in the DR Dockets[1]. In the remaining weeks, we will iterate our modeling results and develop further refined DR programs for the five islands we serve. The additional DR work will align with the ancillary services needed by each of our systems, with program design and costs aligned with market studies developed in the DR Docket. Our DR programs enable our customers to better manage their energy and its cost. We continue to aggressively pursue all DR programs that best meet these goals.

The Necessity of Energy Storage

Our ability to integrate high levels of variable renewable generation requires support from other resources. Dispatchable generation might not always have enough regulating reserve capacity or be the best option to quickly respond to support the fluctuations of variable renewables. At high levels of renewables, we will require additional integrating resources such as DR and energy storage. Fast response energy storage may be necessary or preferred to manage these situations, as well as to store excess renewable generation for later use. We are considering several utility-scale and distributed energy storage alternatives to satisfy the requirements. These resources have not yet been incorporated in our modeling, but will be in the Updated PSIP filed on April 1, 2016.

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[1] Docket Nos. 2007-0341 and 2015-0412.

Status of Findings

We approached the update process by considering near-term needs while still ensuring that we meet our long-term 100% RPS goal.

In all cases being analyzed, we are able to meet not only Hawai'i's goal of a 100% RPS by 2045, but also all milestone RPS targets along the way.

Given an aging generation fleet and our desire to reduce the use of oil and our carbon foot print, we do need to look at the possibility of alternative fuels and generation. Therefore, analyses up to this point have focused more on these near-term challenges.

A smooth transition to a 100% RPS will require an optimal mix of dispatchable generation—including DER, DR, utility-scale renewable generation, and energy storage—to meet demand and support grid operations. In addition, our thermal generating units will need to be more flexible — quick starting, fast ramping, and operating efficiently at both high and low levels of utilization.

Diverse Renewable Energy Mix

In addition to the current renewable energy resources in our portfolio that account for a 22% RPS, the initial set of cases developed thus far includes the following additional renewable energy resources in the consolidated energy portfolio: DG-PV, utility-scale PV, utility-scale wind power, geothermal, biomass and biofuels. In addition, we would plan to end the use of coal after the current contract ends in 2022.

Liquefied Natural Gas (LNG) as a Bridge Fuel

Using petroleum oil in our generating units continues dependence on this resource that is volatile in price and has emissions subject to increasing environmental restrictions. Preliminary results suggest that LNG and fleet modernization (as described below) offer a prudent path forward in the transition to 100% RPS.

The Governor has stated his concern that using LNG will divert focus away from a 100% renewable energy future. We understand our responsibility not to let that happen. We believe we can move aggressively towards 100% renewables with LNG as a transitional bridge fuel through 2040, limiting permanent infrastructure while allowing for variable demand. Our PSIP Update Interim Status Report presents information to compare scenarios with and without LNG.

The Need for Flexible and Efficient Generation

As the Commission has recognized in its Inclinations paper, "the Hawaiian Electric Companies should continue to evaluate opportunities to retire and replace older, high-cost plants with new resources with valuable characteristics that provide required support services cost-effectively to maintain a reliable electricity grid with high levels of renewable resources."[2] One example of a flexible and efficient generator is an advanced combined cycle unit. Such generators have many benefits -- fast starting, offline cycling, fast ramping, fuel efficiency, low emissions, and improved reliability—all of which lower operating costs. The flexibility of these units supports the variable nature of renewable generation and the transition to 100% RPS, as well as reduces the size of costly energy storage systems. When sited at existing generating stations, they can take advantage of existing infrastructure, minimizing the impact to the local community. On Maui, Lana'i, Moloka'i, and Hawai'i Island, existing dispatchable generators in the form of combustion turbines and internal combustion engines already provide a considerable amount of flexible generation. Opportunities to enhance the flexibility of existing generators on all islands will also be considered in conjunction with new generation.

Preliminary results indicate that the lowest overall cost and lowest emissions are achieved in the case that includes a large-scale advanced combined cycle facility to replace older steam generation at the Kahe power plant combined with the use of LNG. More specifically, with input from NextEra Energy, we have identified a 383 MW 3x1 combined cycle facility to replace Kahe Units 1–3 which could use LNG as a substitute for oil. This scenario—only possible as a merged entity—results in lower costs to customers over the planning period of cases evaluated, supports an increasing amount of renewables, reduces environmental emissions, and improves grid reliability and security. Furthermore, this advanced 3x1 combined cycle option appears to be advantageous with or without LNG, but is clearly better when using LNG as a transitional fuel source to get to a 100% RPS. In fact, when utilizing both LNG and the advanced combined cycle option on O'ahu, carbon dioxide emissions would be reduced by over 4.4 million tons by 2023. This is the equivalent of removing over 133,000 passenger vehicles from the road each year.

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[2] Docket No. 2012-0036, Order No. 32052: Regarding Integrated Resource Planning, Exhibit A: Commission's Inclinations on the Future of Hawai'i's Electric Utilities, at 7.

Merged and Unmerged Scenarios

In developing the initial set of resources for various resource plans, in certain cases such as noted above, LNG could only reasonably be procured if the proposed merger of NextEra Energy and Hawaiian Electric Companies is approved. Such a scenario combined with other projects and programs envisioned for this same timeframe (such as Smart Grid, Schofield Generating Station projects, and others) would require the financial backing and development capacity of the merged organization. Additional resource plans that do not include merger-only resources are also being developed for analysis and evaluation.

DEVELOPING OUR PREFERRED PLANS AND FIVE-YEAR ACTION PLANS

The impact of our continually evolving energy environment is magnified with Hawai'i's new 100% RPS goal for 2045. A 30-year planning horizon (double what was used for the 2014 PSIPs) has inherent challenges: near-term opportunities are more definable and require more actionable plans; more time-distant opportunities and needs will be less certain with changing technology, pricing, and policies more likely to occur and impact those plans. With an eye towards the 100% RPS, we are developing candidate plans and preferred plans that focus on objectives and actions for the next five years. At the same time, we are aligning and building on these near-term plans to develop long-term plans that meet the 100% RPS goal reliably and at a reasonable cost.

Updating all the modeling assumptions and constraints for such an extensive update is a significant undertaking, yet much has already been accomplished. The very important step of the development of assumptions and constraints has consumed much of the efforts to date. We plan to further evaluate the cases presented in this interim filing, consider stakeholder input, perform sensitivity analyses around key variables, and assess risk factors associated with each plan.

This PSIP Update Interim Status Report includes the preliminary status of our analyses, based on the work completed thus far. For the cases under review, interim results meet all four consolidated RPS milestones for incorporating renewable resources. The interim results of these consolidated cases, however, do not optimize all resource options. Because of this, these interim results must be considered preliminary.

We recognize the need for a preferred plan in which the analytical results have been optimized for the benefit of our customers. Our planning teams have developed a comprehensive iterative process, utilizing multiple models and consultants, for developing a set of candidate resource plans. This process optimizes new generation additions, existing unit retirements, DER, and DR, all while maintaining system reliability. Results of these analyses will be included in our Updated PSIPs April filing.

Although much work remains to be done, what is clear is that Hawai'i's 100% RPS goal is achievable, technology and pricing will continue to change to make this possible, and foundational investments in more flexible generation and use of cleaner fuels in the transition can be an important step as increasing amounts of variable renewable energy resources are added on our path to 100% renewable energy.

1. Introduction

OVERVIEW OF THE PSIP UPDATE INTERIM STATUS REPORT

The Hawai'i Public Utilities Commission's Order No. 33320 directed the Hawaiian Electric Companies to file a supplemented, amended, and updated PSIPs on or before April 1, 2016.[3]

Our goal in our supplemented, amended, and updated PSIPs is to develop a Preferred Plan and a complementary Five-Year Action Plan for each operating utility that explains how we intend to deliver affordable, reliable, clean energy. Performing the analyses necessary to attain this goal is a complicated resource planning process, requiring new tools and new processes: modeling across generation, transmission, distribution, infrastructure, and behind-the-meter resources options.

Several high-level objectives drive the Company's planning process, chief among them attaining 100% RPS, lowering customer bills and maintaining reliability. A number of variables must be considered, including fleet modernization, replacement generation, distributed energy resources (DER), demand response (DR), energy storage, new technologies, transmission and distribution infrastructure, fuel selections, environmental considerations, system security, capital cost considerations, and others.

Many entities are involved in this process: expert teams from our three operating utilities together with several knowledgeable and experienced consulting firms, each running different modeling tools to analyze various paths toward developing a reasonable Preferred Plan for each utility.

Over the next month and a half leading up to the filing of our Updated PSIPs, we will continue to refine the input into our modeling tools and optimize results through

[3] Order No. 33320 at 174.

repeated analyses iterations. Our continued analyses will create a clear picture of several reasonable alternative plans, from which we will develop Preferred Plans and their complementary Five-Year Action Plan.

This *PSIP Update Interim Status Report*—a precursor toward filing our supplemented, amended, and updated PSIPs—describes the interim results of our extensive and methodical analysis. As directed by the PUC:

> The interim PSIP Update shall present preliminary or interim results of the Companies' supplemental planning analyses and include pertinent available supplemental information to address the commission's Observations and Concerns and the initial responses of Parties.[4]

The material presented herein does not represent a final set of analysis or plans nor does it represent the full breadth of resource options for analysis. These interim results are essentially a snapshot of our progress to date. Because of their interim nature, these results indicate an initial direction of how the results of our subsequent analysis will proceed; but a cautionary note is in order as that direction could change as we perform further analysis and optimization.

[4] Docket 2014-0183, Decision and Order No. 33320, p 174.

ATTAINING 100% RPS

The Hawai‘i State legislature mandates that each electric utility company that sells electricity for consumption in Hawai‘i must establish set percentages of “renewable electrical energy” sales.

Milestone Date	Renewable electrical energy generation as a percentage of sales
December 31, 2020	30%
December 31, 2030	40%
December 31, 2040	70%
December 31, 2045	100%

Table 1-1. State RPS for Renewable Energy Sales

Subject to Commission approval of the proposed merger docket, Hawaiian Electric Companies and NextEra Energy stated their intent to “undertake good faith efforts to achieve a consolidated RPS “ more aggressive than the statutory requirements.

Milestone Date	HRS §269-92	Hawaiian Electric Companies and NextEra Energy’s Commitment for Renewable Energy
December 31, 2020	30%	35% of sales
December 31, 2030	40%	50% of sales
December 31, 2040	70%	70% of sales
December 31, 2045	100%	100% of sales

Table 1-2. Increased Merger Commitments for Meeting State RPS Mandate

The Companies are committed to transforming the generation fleet so that 100% of the power generated comes from renewable sources. Thus, under the RPS formula established by the Legislature, we will exceed the 100% RPS goal.

COMPONENTS FOR ACHIEVING THE 100% RPS TARGET

Hawai‘i has set a bold target for achieving a 100% RPS by 2045. In order for the state to meet these targets, a thorough evaluation of the options available must be undertaken. It is our belief that this can be best understood with a methodical analysis of the building blocks needed to achieve a 100% RPS solution.

The Role of Distributed Energy Resources (DER)

Distributed Energy Resources (DER) provides a core component of the potential renewable additions to the islands. DER may take many forms and may encompass several approaches, including demand response, energy efficiency, electric vehicles, generation and storage technologies.

As we evaluate the landscape today, the most significant form of DER is the application of DG-PV: solar generation across the homes and businesses of Hawai‘i. While a critical component of our efforts to achieve a 100% renewable future, the implementation, timing, and adoption of residential and commercial solar generation is not fully within our control, nor necessarily the Commission’s. Rather it will be dictated in large part by the individual decisions of businesses and homeowners in response to products and service offerings from an emerging DER market.

Table 1-3 depicts the total projected installed capacities of the optimized DG-PV forecasts for the RPS milestone dates for the entire planning period of the Updated PSIPs.

Milestone Date	Optimized DG-PV Forecast
December 31, 2015	487 MW
December 31, 2020	849 MW
December 31, 2030	989 MW
December 31, 2040	1,185 MW
December 31, 2045	1,312 MW
Growth (2015–2045)	~180%

Table 1-3. DG-PV Forecast (Preliminary)

In developing the PSIP, we have sought to estimate the likely rate of distributed PV adoption, ensuring any plan is robust enough to encompass higher or lower adoption rates while maintaining a path towards a 100% RPS. Our PSIP will take these sensitivities into account. We are committed to continuing to evaluate and optimize DER under various adoption rates and will include these analyses for our Updated PSIPs. It’s important to understand, though, that DER alone cannot meet the 100% RPS targets for Hawai‘i.

Optimizing Distributed Energy Resources

With 23% of single family homes already operating rooftop PV systems, the Hawaiian Electric Companies are leaders in the initial growth stage of DER. On O‘ahu alone, 32% of single family homes have rooftop PV systems installed or approved for installation. Coupled with continued innovation in other forms of DER—such as electric vehicles (EV) and distributed energy storage systems (DESS)—the utilities must proactively plan for future additions of DER. The rapid adoption of these technologies will require the utilities to design programs and develop distribution system infrastructure to optimize the system, leverage these resources in planning and operations and maximize customer benefits.

Optimizing the system implies utilizing the resources in a cost-effective and reliable manner to ensure minimized overall customer bills. Further, with more DER options, the customer can effectively be a "prosumer", that is one who consumes utility power supply and utilizes grid services as well as provides power supply and grid support services to the utility and for oneself.

To ensure both an optimal system and maximum customer benefits, DER provision of power supply and grid services should be maximized when DER can provide the services cost effectively and efficiently. Put another way, if DER can adequately and reliably provide these services, and it is cost-effective, customers should be enabled to provide power supply and grid services to the electric system ("customer choice"). Enabling customer choice cost-effectively is one of several objectives of the PSIPs.

Cost-Effective Utility-Scale Renewable Generation

To complement the DER, we plan to optimize the use of cost-effective, utility scale renewable solutions. This begins with analyzing the utility-scale wind and solar generation additions on O‘ahu, and geothermal and biomass on Maui and Hawai‘i Island that were included in the 2014 PSIPs to ensure that they can be integrated in a cost effective and environmentally sensitive manner on all islands, and evaluating the cost-effectiveness of wind, solar and other feasible resource options for Maui, Moloka‘i and Lana‘i and Hawai‘i Islands. The power systems in Hawai‘i have abundant renewable resource potential, but face many challenges due to the nature of the island system and unique characteristics and system capabilities of each island. The approach utilized in the development of the PSIP methodically evaluates the feasibility of adding utility scale renewable wind and solar to each island. Several supporting efforts have been undertaken, and are still underway, to better understand the reasonable wind and solar resource capability of each island. Consideration will be given to offshore wind resources as the availability of developable on-island wind sites may be a factor on some of the islands.

On an overall basis it is clear that even when combined with the contribution from DER, the resulting generation from renewable resources, while significant, is not sufficient to reach a 100% RPS solution. The analysis approach will therefore involve maximizing the available renewable resources on each island, and then complementing these resources with a combination of some or all of the following:

- Liquefied natural gas (LNG) as a cost-effective transitional bridge fuel toward attaining 100% RPS.
- Renewable fuels burned in existing or modernized generation facilities.
- Offshore wind resources that would be constructed on floating platforms.
- The addition of an inter-island cable, which would function as a grid-tie with O‘ahu and unlock the development of additional renewable resources on other islands such as Maui where renewable resource potential exceeds what could reasonably be consumed locally.
- The addition of energy storage systems.

Renewable Biofuels

Renewable biofuels, depending on their cost, can play a role in achieving the 100% RPS level. Utilizing biofuels as a complement to DER, wind, solar and energy storage has the benefit of using a portion of the conventional dispatchable generation mix as part of the overall generation solution. This can help avoid the commitment of new capital for renewable generation. The flexibility of the dispatchable generators will be a critical component in compensating for the variable nature of the wind and solar resources, thereby helping to ensure that system stability and reliability can be maintained in conjunction with a high penetration of variable renewable resources. And hopefully, more biofuels can be locally produced, keeping more monetary resources in-state.

LNG as a Cost-Effective Transitional Bridge Fuel

The Company believes that we must achieve the 100% RPS goal in a cost-effective manner. We therefore believe that LNG may be a vital component on the path towards 100% RPS because it will allow us to significantly lower emissions, reduce fuel costs, and reduce customer bills.

There are essentially two alternatives to LNG. First, we can continue to utilize our existing generating fleet and switch to higher cost biofuels, which will increase customer bills. Second, we can aggressively install new utility-scale solar PV and wind generation, with high upfront capital costs and potentially high levels of capital cost associated with energy storage. This will also increase customer bills substantially. Preliminary results suggest that LNG and fleet modernization offer a prudent path forward in the transition to 100% RPS. To be clear, we might achieve the RPS targets faster without LNG, but the tradeoff could be substantially higher customer bills.

Inter-Island Transmission

We have not yet analyzed how inter-island cables, either grid-connected or generation-connected, can cost-effectively contribute to achieving 100% RPS. To comply with the Commission's directive, we plan to fully develop this analysis for our Updated PSIPs, including an analysis of the benefit of increasing use of wind, solar and possibly other forms of renewable generation from the neighbor islands beyond their individual island's use and the operational benefit of pooling dispatchable generation across islands to reduce dispatch costs.

Energy Storage

Energy storage can be provided by batteries, pumped storage hydro, or flywheels.

Variable generation resources, such as wind and solar, produce energy that is not necessarily coincident with customers' energy consumption. Therefore, energy storage is expected to play a role in storing excess energy when it is produced and discharging it when customers need it. Energy storage can be utility-scale or distributed at the customer level. Either one can serve a load-shifting function to help achieve 100% RPS.

Energy storage can also provide ancillary services, such as inertial response, contingency reserve and regulating reserve. Using storage to provide these functions provides an alternative to procuring these services from online generation and can increase the ability of the system to accept more renewable energy.

Energy storage will play a necessary and vital role in the integration of renewable resources and at the same time, support the reliability and resiliency of Hawai'i's multi-island electric grid as it advances to a 100% renewable future.

Energy storage is a set of rapidly advancing technologies and the Companies believe that there will continue to be transformative shifts that will further enable the integration of renewables onto the system. As we develop a viable and robust PSIP, the use, understanding, economics, and performance of energy storage technologies will remain an important component of the overall plan.

The cost of energy storage will be factored in when determining the extent to which energy storage will be deployed to reach the 100% RPS level. The cost of wind, solar and energy storage combinations will be compared with other renewable energy options, to move toward an optimal mix of renewable energy and energy storage resources.

Further investments to the grid and distribution system will also be needed to maintain a reliable and resilient system. Customers and stakeholders alike expect reliable delivery of electricity to their homes and businesses and it will be necessary to bolster the strength of our grid to accommodate increasing amounts of variable renewable resources and DER.

As a whole, the combination of DER with utility-scale wind and solar, supplemented by biofuel and dispatchable renewable generation, present a path by which Hawai‘i could achieve a 100% RPS in 2045.

OVERVIEW OF THE PSIP UPDATE INTERIM STATUS REPORT

This document is organized as follows:

Chapter 1. Introduction: An introduction to and an overview of renewable resources and how they affect our Updated PSIPs.

Chapter 2. Input from the Parties: A discussion of how we handle input received from the Parties to this docket.

Chapter 3. Analysis Methodologies: A detailed discussion of the resource planning decision framework we are using to develop our Updated PSIPs.

Chapter 4. Modeling Assumptions: An overview of the assumptions we are using in our modeling and analysis. Details can be found in Appendix D.

Chapter 5. Interim Results: A snapshot of our interim results to date, including how we are addressing the Commissions eight Observations and Concerns.

Chapter 6. Next Steps: A overview of modeling, analysis, and evaluation we are conducting toward creating our Updated PSIPs.

Appendices A–E: A series of appendices that provide supporting information and more detailed discussions regarding our work to date, and our ongoing analysis.

2. Input from the Parties

As defined in Order No. 33320, the term "Parties" in this docket refers "collectively to the Parties, Intervenors, and Participants in this proceeding."[5]

CONSIDERING AND INCORPORATING INPUT FROM THE PARTIES

Order No. 33320 directed the Parties in the docket to file a report on January 15, 2016 that included, among other topics, input to our process for creating Updated PSIPs.

In our *Proposed PSIP Revision Plan*, we stated that:

> The Companies welcome and actively seek to obtain input from the Parties and other stakeholders regarding the assumptions, methods, and evaluation metrics. … (T)he Companies encourage the Parties to provide constructive inputs related to the Commission's Observations and Concerns, supplemented with appropriate quantitative justification, methodology, assumptions, and information sources that can apply to the creation of actionable updated PSIPs. This input can be particularly impactful to our analyses. The Companies will incorporate input submitted by the Parties to the extent that time allows.[6]

To assist the Parties, our *Proposed PSIP Revision Plan*[7] contained a table[8] describing, in detail, the high priority inputs to the Commission's eight Observations and Concerns that we require for our analysis.

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[5] Order No. 33320 at 171.

[6] *Hawaiian Electric Companies' Proposed PSIP Revision Plan*, pp 28–29.

[7] Docket No. 2014-0183, Order No. 33320 Compliance Filing, November 25, 2015.

[8] Table 1. High Priority Input Required for our Analysis, *Hawaiian Electric Companies' Proposed PSIP Revision Plan*, pp 29–31.

Nineteen of the twenty-three Parties submitted input to comply with the Commission's directive for filing on January 15, 2016:

Consumer Advocate	County of Hawai'i (CoH)
County of Maui (CoM)	Dept. of Business, Economic Development, & Tourism (DBEDT)
Blue Planet Foundation	Distributed Energy Resources Council of Hawai'i (DERC)
Eurus	Hawai'i PV Coalition (HPVC)
Hawai'i Gas	Hawai'i Solar Energy Association (HSEA)
Life of the Land (LOL)	Renewable Energy Action Coalition of Hawai'i (REACH)
Paniolo Power	SunEdison (First Wind)
Sierra Club	SunPower
Tawhiri	The Alliance for Solar Choice (TASC)
Ulupono Initiative	

Four Parties did not file a response: AES Hawai'i, Hawai'i Renewable Energy Alliance (HREA), NextEra Energy Hawai'i, and Puna Pono Alliance.

How We Considered and Incorporated Input from the Parties

We reviewed each Party's filing in detail and organized their input into 15 topics. We then decided how to incorporate the topic into our analysis, and when we would be performing this analysis by assigning each topic a timing status:

- Out of scope. We recognize the Commission's specific instructions to limit issues in the PSIP Update to the issues established by the Commission. (Order No. 33320 specifically states that the Parties' "participation will be limited to the issues as established by the commission in this docket.")[9]
- Addressed or incorporated in this PSIP Update Interim Status Report.
- Addressed or incorporated in our Updated PSIPs (to be filed on or before April 1, 2016).
- To be addressed in our resource planning that will continue after filing the Updated PSIPs.

Appendix B: Responding to Party Input (page B-1) presents these 15 topics, the summarized input we assigned to each of these topics, our action regarding each topic, the Parties submitting input to this topic, and the status of each topic.

Our Updated PSIPs (to be filed on or before April 1, 2016) will contain an appendix detailing the points made by each Party in their January 15, 2016 filings, and our responses.

[9] Order No. 33320 at 171.

To date, we have incorporated several key points of feedback from the Parties in the PSIP Update thus far. These include:

- Distribution of resource cost assumptions to the Parties on February 2, 2016.
- Establishment of an FTP site where input information and data developed thus far in the PSIP process is posted so the Parties can access it and post feedback.
- Use of a "decision framework" to establish a clear basis for how plan objectives will be prioritized.
- Introduction of PSIP optimization processes consisting of DER, DR, and utility-scale iterative cycles to capture analytical steps in achieving our 100% RPS goals.
- Invitation of intervenor representatives to participate in working meetings with the Hawaiian Electric Companies working team on the remainder of analysis and modeling for the Updated PSIPs.

Input Incorporated from Other Organizations

Our *Proposed PSIP Revision Plan* listed six additional organizations who agreed to provide independent technical analyses to help address issues of concern for the updated PSIPs. These stakeholders include the Hawai‘i Natural Energy Institute (HNEI), Electric Power Research Institute (EPRI), U.S. Department of Energy, University of Hawai‘i Economic Research Organization (UHERO), National Renewable Energy Laboratory (NREL), and Hawai‘i Energy.

NREL has performed an independent review of our new resource assumptions and an independent analysis of the wind and solar PV "developable" potential for each island. EPRI provided access to their database for developing resource costs. HNEI and an additional stakeholder, General Electric, provided input on regulating reserve requirements.

We are still working with all of these organizations while we continue our analyses for developing our Updated PSIPs.

STAKEHOLDER AND TECHNICAL CONFERENCES

Beginning with our *Proposed PSIP Revision Plan*, we have made it clear that we are proactively soliciting input from the Parties. In that filing, we proposed a schedule of conferences for just this purpose:

- Stakeholder Conference: held on December 17, 2015
- Technical Conference: proposed to be held on February 22, 2016
- Technical Conference: proposed to be held on April 15, 2016

The Commission also scheduled a Technical Conference held on January 7, 2016

Stakeholder Conference: December 17, 2015

On Thursday, December 17, 2015, we convened a three-hour stakeholder conference. Colton Ching, Hawaiian Electric Vice President of Energy Delivery, introduced the conference; Mark Glick, DBEDT Energy Administrator, moderated the conference; Chris Yunker, DBEDT Energy Systems and Planning Program Manager, facilitated.

Our goals for the stakeholder conference were two-fold:

- **Overall Objective:** To obtain a clearer understanding of potential input from the Parties and how it might affect how we develop the PSIP Updates.
- **Process Considerations:** Discuss the objectives of the process set forth by the Commission in Order No. 33320, answer specific questions regarding the PSIP analysis process, and discuss any other pertinent issues raised by the stakeholders.

We invited over 40 people to the conference, including representative from all Parties and the Commission and about 40 people (excluding company personnel) attended either in person or through a phone-in bridge. As we recommended, the meeting was fairly informal to better solicit candid remarks.

The conference featured four presentations. Mr. Glick's focused on garnering input from attendees regarding the Commission's eight Observations and Concerns. Mr. Yunker presented on how we plan to achieve an energy future that meets or exceeds the state's public policy goals.

Erik Kvam of REACH presented its recommendations for a process to develop a mix of resource options for attaining 100% renewable generation. Matthias Fripp, professor at the University of Hawaiʻi and a consultant to Blue Planet Foundation, presented how a Switch Optimization Model can be employed to develop the resource option necessary for achieving 100% renewable power on Oʻahu.

The following day, the Companies held an internal meeting to discuss the stakeholder conference, its outcomes, and our plan for incorporating the information we obtained.

Technical Conference: January 7, 2016

The Commission organized a 3-hour technical conference on January 7, 2016. The Commission invited representative from all Parties in the docket.

In its letter announcing this conference, the Commission stated its purpose:

> The purpose and scope of the technical conference is to further examine and understand the Hosting Capacity Analyses submitted by the HECO Companies. In particular, the commission seeks to better understand (1) the assumptions used in the analyses; (2) methodologies utilized by the HECO Companies to determine system-level and circuit-level hosting capacity; and (3) the HECO Companies' plans for further refinement of these analyses.[10]

The Commission also directed the Companies to give a presentation on these topics to begin the conference. Colton Ching, Hawaiian Electric Vice President of Energy Delivery, made this presentation. The presentation recapped our *Proposed PSIP Revision Plan*, provided status on how we were addressing the Commission's eight Observations and Concerns, discussed supply-side resources and their related costs, and presented next steps. Mr. Ching then addressed questions from attendees.

Proposed Technical Conference: February 22, 2016

For this conference we have proposed to discuss the overarching PSIP principles, present an overview on PSIP technical development process (for example, methodologies, models, and key assumptions, including content development), and present preliminary analyses and results. More importantly, though, we plan to solicit constructive feedback, the results of any substantiated analyses from the Parties, and well-considered recommendations that we can include in our ongoing analyses based on the filing of our interim update.

We are awaiting Commission decision regarding the Companies' proposal for this meeting.

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[10] Commission letter, dated December 22, 2015, signed by Robert R. Mould, Economist.

Proposed Technical Conference: April 15, 2016

During this last technical conference, we propose to present and discuss the supplemented, amended, and updated set of PSIP conclusions, recommendations, Preferred Plans, and their complementary five-year action plans. In addition, we plan to present and discuss the analyses and results from addressing the Commission's eight Observations and Concerns, and discuss both the near-term and long-term customer rates and bill impacts.

We are awaiting Commission decision regarding the Companies' proposal for this meeting.

3. Analysis Methodologies

RESOURCE PLANNING DECISION FRAMEWORK

The issues related to planning the future of Hawai‘i’s power systems are complex and in many ways represent uncharted territory for any utility performing long-term resource planning. There is no single computer program or model that incorporates the logic to evaluate the many issues that must be addressed in Hawai‘i.

We must consider the “optimization” of a number of resource options, including commercial and emerging DER options, DR, and a number of commercial and emerging utility-scale resources, over a 30-year planning horizon. This optimization must take into account the unique system reliability issues in island systems with no interconnections to other systems. Further, there are a host of external factors that must be considered, including customer behavior, global energy market conditions and expectations, state energy policy objectives and competing agendas of various stakeholders.

The methods and techniques used by the utility industry in the past are simply not sufficient to accomplish the analysis required to address these many factors. A key objective is to make this planning process clear and transparent despite its complex nature. This section describes this complex planning exercise by describing the framework by which various options were considered (Decision Framework) and the approach by which optimal plans were developed (PSIP Planning and Modeling).

Decision Framework

Four factors comprise a decision framework: Objectives, Requirements, Input Parameters, and Decision Variables (Table 3-4).

Factor	Description
Objectives	The specific results that the planning process aims to achieve. It's important that these objectives be precise.
Requirements	Fixed parameters around which a plan must be built and do not vary between plans or plan sensitivities
Input Parameters	Parameters that are not fixed like a Requirement, but are also not a variable that can be controlled to optimize toward achieving the Objectives. Input Parameters can be varied to deal with the uncertainty and to understand the sensitivity of a plan to a change in assumptions.
Decision Variables	Variables that can be varied toward achieving the Objectives. Decision Variables include resources and programs that can be leveraged by the utility in a given plan to achieve the Objectives.

Table 3-4. Resource Planning Decision Framework

The objectives, requirements, and input parameters all feed into the decision variables (Figure 3-1 depicts how these four factors interact).

Figure 3-1 depicts the quantities and timing of resources (including DER, utility-scale resources, and DR programs) on the electric system that are varied to achieve the Objectives, while meeting fixed Requirements, and considering the Input Parameters as assumptions.

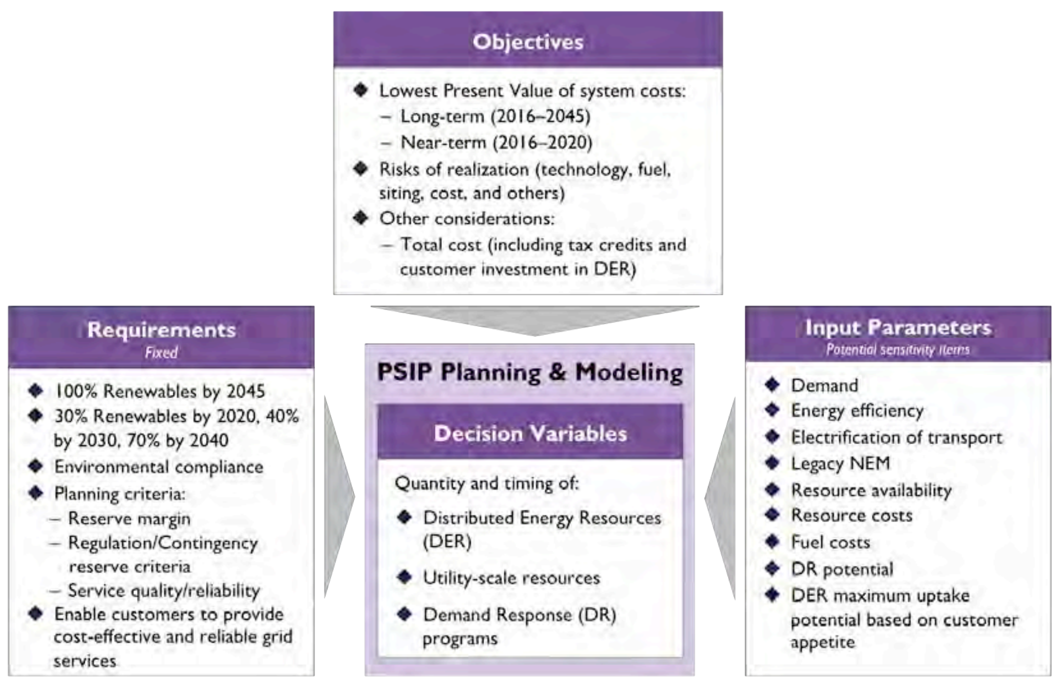

Figure 3-1. Overview of the Decision Framework

Objectives

Objectives are the specific results that the planning process aims to achieve. Objectives of the PSIP Planning and Modeling process include lowest total system costs over time, minimized risks, and other considerations.

Lowest total system costs. Minimizing customer cost is a primary objective of the planning process. Total system costs consider the present value of total costs to the electric system, including generation, transmission & distribution, interconnection, and integration costs. Recognizing that near-term cost assumptions are more certain than long-term cost assumptions, both near-term (2016–2020) and long-term (2016–2045) costs will be considered.

Manage risks. Any forecast has uncertainty, which in turn introduces risk to a plan that is implemented based on that forecast. Examples of risks for a given plan include, but are not limited to: forecasted technology cost reductions may not materialize; fuel costs may actually be higher or lower than as forecasted; new technologies do not become available as forecasted; new resources assumed in a given case cannot be constructed because of the inability to obtain permits; and other factors. Risk will be assessed and risk mitigations will be proposed for candidate plans in the April 1 PSIP Update filing. There was not sufficient time for the February 16 PSIP Update Interim Status Report to conduct a full risk assessment.

Other considerations. Although minimizing customer cost is a primary objective, there are other considerations to take into account. For example, one plan may be more costly than another, but may achieve greater levels of renewable energy deployment, and so that plan may be preferred by some stakeholders. Another plan may result in the lowest revenue requirements from a utility point of view, and therefore have the most favorable impact on customer bills, but that plan may require large subsidies (for example, tax credits) and customer investments, so it might have a higher total cost including subsidies and customer investments. These kinds of considerations will be noted for each candidate plan in the April 1 PSIP Update filing.

Requirements

Requirements are fixed parameters around which a plan must be built. Requirements do not vary between plans or plan sensitivities. Requirements include RPS mandates, other regulatory compliance, planning criteria, and customer choice.

RPS mandates. The Hawai‘i legislature mandates that each operating utility must meet the RPS “renewable electrical energy” sales requirements over the next 30 years.

Other regulatory compliance. Plans must comply with various state and federal laws and regulations, including applicable environmental laws and regulations.

Planning criteria. Planning criteria are standards for safe, reliable power supply for customers. Planning criteria are developed considering system security requirements, including system reliability, loss of load probability, service quality, and adequacy of supply necessary to maintain an acceptable level of reliability. The specific planning criteria include capacity reserve margin, operating reserves, and resource requirements.

Enabling Cost-Effective Customer Choice. With more DER options, the customer can effectively be a "prosumer", that is one who both consumes energy or uses utility services as well as provides services to the utility. We will continue to work to enable customers to provide grid services to the electric system; however, the price for such grid services must reflect their economic value relative to other resources.

Input Parameters

Input Parameters are parameters that are not fixed like a Requirement, but are also not varied like Decision Variable to achieve the Objectives. Input Parameters have various levels of uncertainty and so can be varied to understand their impact on the Objectives (as a sensitivity analysis), but they are not a Decision Variable that can be controlled to achieve the Objectives. Input Parameters include demand for electricity, energy efficiency achievement, adoption of electrified transport, legacy NEM installations, resource availability, resource costs, fuel costs, DER potential, and DR potential.

Demand, Energy efficiency, Electrification of transport, Legacy NEM. There are various Input Parameters including demand for electricity, energy efficiency achievement, adoption of electrified transport, and legacy net energy metering (NEM) installations that in summation determine the amount of net electricity that the system must generate.

Resource availability, resource costs, fuel costs. Resource availability, resource costs, and fuel costs determine what resources are available and at what cost to provide power supply and grid services. An example of resource availability is the amount of solar PV that can be permitted and installed on the island of O‘ahu, subject to constraints like land availability and permitting feasibility. Resource costs include capital and operating cost forecasts for: solar, wind, energy storage, biomass, waste-to-energy, geothermal and fossil generation technologies. Fuel costs include cost forecasts for LNG, oil, and biofuels. Resource cost forecasts are inherently uncertain, particularly for emerging technologies. Fuel prices are volatile, making fuel forecasts uncertain. Fuel costs will be varied to understand the sensitivity of candidate plans to changes in these Input Parameters.

DER potential, DR potential. DER and DR might provide multiple grid services. We must determine the total potential that these programs could contribute ('potential") to the candidate plans. DR includes programs that leverage a variety of flexible customer-sited resources to provide grid services.

Decision Variables

Decision Variables can be varied to achieve the Objectives. Decision Variables include resources and programs that can be leveraged by the utility to achieve the Objectives, while satisfying the Requirements, given the Input Parameters as assumptions related to the electric system. Resources and programs include DER (for example, DG-PV, distributed energy storage systems (DESS)), utility-scale resources (for example, PV, wind, biomass, waste-to-energy, conventional generation using oil, LNG, biofuels), and DR programs (for example, fast frequency response, time-of-use rates). Decision Variables include the quantity and the timing of deploying these options.

Quantity and timing. The quantity and timing of DER, utility-scale resources, and DR programs and their utilization in the systems are varied in candidate plans to optimize toward achieving the Objectives.

SYSTEM SECURITY

System security is the ability of an electric power system to regain a state of operating equilibrium and maintain acceptable reliability when subjected to possible events. These events - or contingencies - include loss of generation or electrical faults that can cause sudden changes to frequency, voltage, and current. Operating equilibrium must be restored to prevent damage to utility and end-use equipment, and to ensure public safety.

System security requirements are incorporated into this PSIP interim update to provide an adequate level of reliability. The need for system security requirements is included in the candidate resource plans. Currently, generators provide the majority of the necessary system security attributes but at some point in time, DR and energy storage resources may be available in sufficient capacities to augment and replace these generators used for this purpose.

The system security analysis for the PSIP update will build upon the simulations performed for the IDRPP Supplemental Filing to identify fast frequency response requirements for each island system. The PSIP update will also include revised definitions for ancillary services and a revised HI-TPL-001 (Transmission Planning Performance Requirements).

For details, refer to Appendix E: System Security.

PSIP PLANNING AND MODELING

In electric system planning, there is no single tool or model that can simultaneously optimize across DER, utility-scale resources, and DR programs while ensuring circuit and system reliability. As such, in the PSIP Planning and Modeling, iterative cycles will be conducted to characterize and analyze each of the DER, utility-scale resources, and DR programs to meet the Requirements and Objectives. These will then be brought together into a production simulation to model the overall system. Results from this production simulation will provide outputs of relevant factors for each program and resource and provide planners with insights on how inputs drive the outputs and on how successive rounds of iteration should be performed. New results from the iteration will then feed into the production simulation of the overall system. These iterative cycles will continue until reasonably optimal results are achieved.

Figure 3-2 illustrates the PSIP Planning and Modeling process. The plans shared in this interim filing reflect the initial run of the PSIP Planning and Modeling process. It should be noted that these processes involve multiple internal resources and modeling efforts. Throughput of a single iteration takes time, with multiple reviews and validations at various points during each iteration. There has not been sufficient time yet to cycle through multiple iterations of the PSIP Planning and Modeling process to achieve a system optimum.

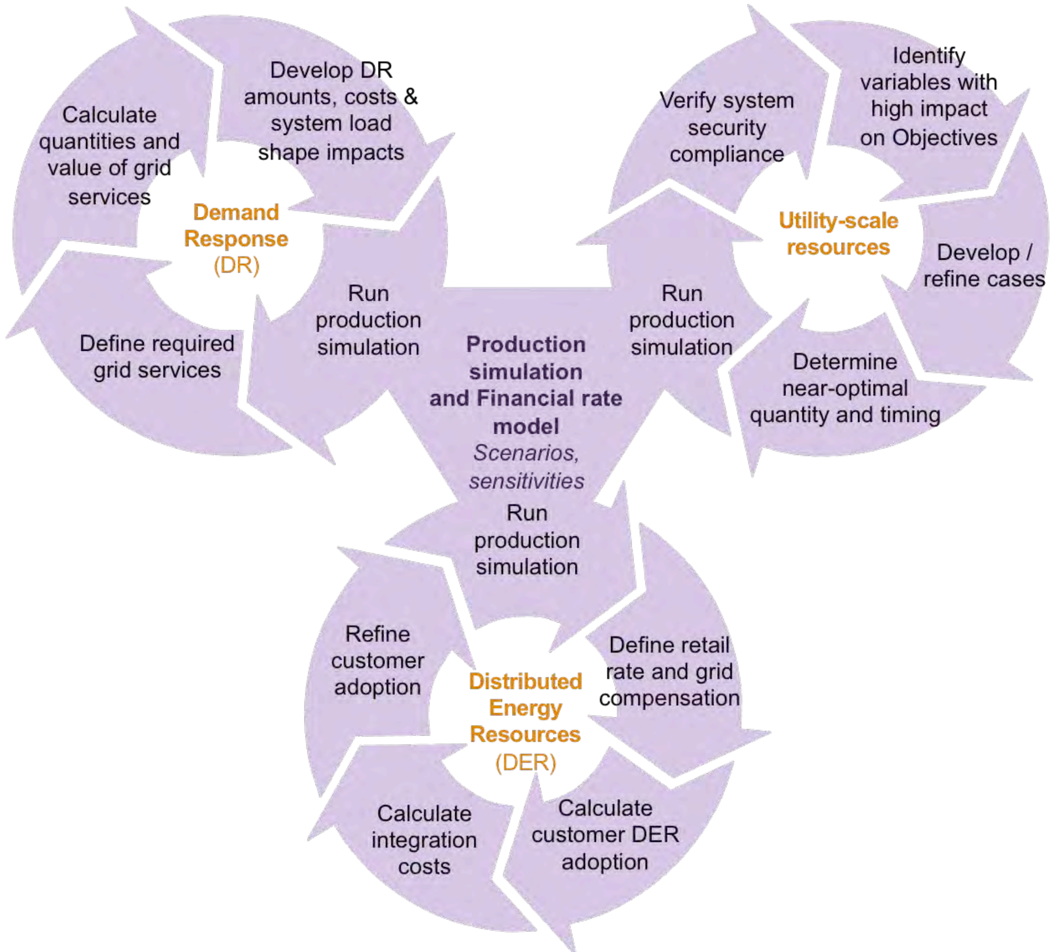

Figure 3-2. PSIP Optimization Process for DER, DR, and Utility-Scale Resources

The following section explain each of these three iterative cycles.

DISTRIBUTED ENERGY RESOURCES ITERATIVE CYCLE

DER includes assets like DG-PV and DESS that play a critical and growing role in the future electric system. These assets are installed based on customer decision making criteria including cost savings on electricity consumption and revenue from the provision of grid services through DR programs. Hawaiian Electric will plan to utilize, integrate and optimize DER into the generation resource mix from a system perspective, but it is the customer who ultimately decides whether or not to install a DER asset. Because of this paradigm, as an initial step, the approach was taken to first forecast the potential DER assets that customers would be willing to adopt based on preliminary assumptions on customer economics related to DER. As an initial step in the analysis, the approach from the system perspective is to integrate the new DER export into the resource mix as long as it is below avoided cost for alternative generation assets with similar attributes. (Existing DER programs, including legacy NEM, SIA, Grid Supply to cap, and Self Supply are assumed to run through their current program life at current compensation levels. See Appendix D for further detail).

For the April 1 filing, we will refine the economic adoption assumptions, and are developing programs to enhance this adoption rate—programs that optimize and provide the most benefits for our customers and grid services in conjunction with other renewable resources in our future portfolio.

In addition, to aid in the DER analysis and in recognition of the other attributes of DER, we are planning to include a "maximum DER" case in the April 1 filing that will look at even higher potential levels of DER based on variations of the baseline assumptions including forgoing the least cost objective.

Forecast payback time of DER system. The payback time of a customer-sited DER system is determined by the customer benefits received over time, versus the customer's cost for the DER system[11]. On the benefits side, the DER system may offset the customer's retail electricity purchases and/or the customer may be compensated by the utility for providing grid services to the electric system.

Forecast payback time for DG-PV compensation. Order No. 33258 to Investigate Distributed Energy Resource Policies has a specified compensation rate and cap by island for a new grid-supply product. As a preliminary assumption, for export of future new DG-PV not covered under the existing programs and aligned with an Objective to achieve lowest cost, DG-PV compensation was assumed to be as follows:

- Consider resources with similar variable generation attributes, to avoid inequitable comparisons to firm generation resources.
- Consider resources with comparable time-of-day production (for example, those resources producing during solar generation hours).
- Enable full utilization of DG-PV on the system. Under economic dispatch principles, this implies compensating DG-PV at the same level as alternative energy resources with similar attributes (renewable, variable, producing during solar generation hours).
- Model the DG-PV resource as controllable and curtailable, similar to other variable generation resources.

With the above considerations in mind, the DG-PV reference resource for comparison purposes is utility-scale solar PV generation. Therefore for the purposes of the initial PSIP update modeling, the future DG-PV export rate was assumed to mirror the

[11] The assumptions in Appendix A include forecasts for the cost of residential solar PV, commercial solar PV, and residential energy storage. These cost forecasts were developed in conjunction with the utility -scale cost assumptions utilizing the same base data sources and assumptions.

respective levelized cost of energy (LCOE) of utility-scale solar for every year of the planning horizon. This assumption ensures optimal amounts of DG-PV are deployed, and those deployed amounts will be fully utilized by the system under economic dispatch principles.

The assumed export rate should not be considered as a policy decision or final view of the Hawaiian Electric Companies and might be further refined as additional analysis is completed.

Forecast payback time – Other DER compensation. Retail electricity price and the value of grid services are a function of the overall electric system. Retail electricity price forecasts are derived from the production simulation and financial rate model. Value of grid services are derived from the production simulation and DR modeling (please see next section for further detail).

Forecast payback time – Cost forecasts. DER technology capital cost and operations and maintenance (O&M) cost forecasts are included. Payback time is forecasted based on the revenues and costs.

DER Controllability. The Companies have assumed that control of customer DG will be feasible by mid-2018. This assumption is based upon the following contributing assumptions:

- Assume Commission approval by the end of 2016 for Demand Response and the end of 2017 for DER.
- The DRMS is expected to be implemented by mid-2017. This application incorporates not only traditional DRMS functionality, but a full suite of distributed energy management capabilities currently in production and under development by OMNETRIC. It is anticipated that this application will be used to control a wide array of distributed energy resources, regardless as to whether they are enrolled specifically in a DR program.
- Policies and programs - including pricing programs - that stipulate the parameters within which control of a distributed energy resource may be administered will be in place by mid-2018. These policies and programs are expected to be captured jointly between current DR program filings and the anticipated efforts within the DER Phase II proceedings.
- Ideally, the Companies will leverage a Company-owned communications network to exercise DER control. However, the Companies' AMI infrastructure is not currently expected to be deployed until after 2018. Based on discussions with aggregators and providers of distributed energy resources, the Companies expect that these aggregators will provide near-term communications sufficient for the preliminary stage of DG control and the associated feedback loop.

Forecast customer DER adoption. If payback time is short, more customers will adopt DER; if payback time is long, fewer customers will adopt DER. Based on the historical correlation between payback time and adoption of DG-PV, and based on forecasted payback time of DER systems, an initial forecast of customer adoption of future DER is calculated.

Calculate integration costs and curtailment amounts (if applicable). In Order No. 33320, the Commission directed the Companies to consider integration costs related to DER deployment and utilization in the power system.

When DG-PV installations exceed the circuit hosting capacity limit, circuit upgrades are required and/or some curtailment may be required. Integration costs and curtailment amounts to accommodate DG-PV over the circuit hosting capacity limit will be calculated by circuit. System hosting capacity screening will also be applied to measure impact of growing DG-PV integration and consequence on system curtailment or other integration requirements (for example, adding storage system). To address the Commission's concerns the Companies are in the process of developing an integration cost methodology that will quantify the impact on circuits resulting from various levels of DG-PV integration, identify integration solutions and their respective costs, calculate curtailment amounts, and apply those integration costs and curtailment amounts to adjust the economics and the expected adoption from system and customer perspectives.

The methodology and analytical work to calculate integration costs and curtailment amounts are in process. There was not sufficient time to incorporate these into this initial run for the February 16 PSIP Update Interim Status Report. These costs will be incorporated in the April 1 PSIP Update filing.

Figure 3-3 depicts a high-level overview on the methodology that is currently under development.

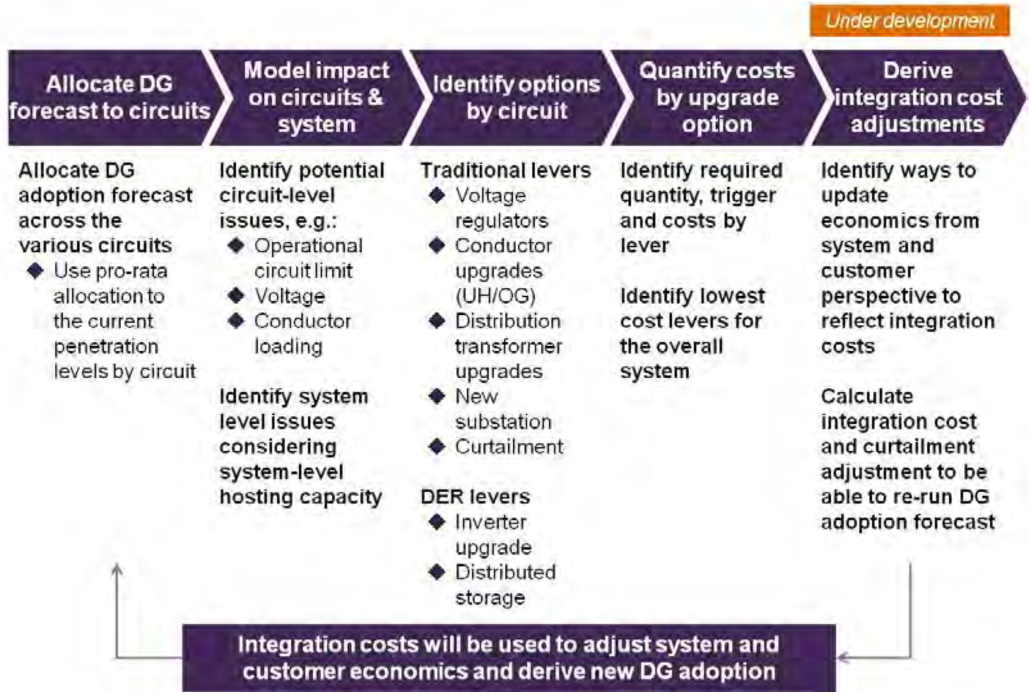

Figure 3-3. Integration Cost Methodology (under development)

Refine customer DER adoption levels. For those customers adopting DG-PV above the circuit hosting capacity limit, or on systems where system level hosting capacities are reached, the value of the DG-PV to the electric system will be impacted by integration costs and curtailment amounts. Integration costs and curtailment amounts may result in a refined payback time and associated customer adoption for those installing a DG-PV system above the circuit hosting capacity limit.

For the purposes of this interim PSIP update, it is assumed that integration costs will be allocated to those customers who install a DG-PV system above the circuit hosting capacity limit; these costs were not assumed to be allocated to other customers. *This is a preliminary assumption only for purposes of the interim PSIP update and can be further refined as additional analysis is completed or available*. The Companies are open to further discussion of this assumption with stakeholders in the appropriate proceeding (including under Docket No. 2014-0192 - Instituting a Proceeding to Investigate Distributed Energy Resource Policies).

For the April 1 filing, we will refine the economic adoption assumptions, and are developing programs to enhance this adoption rate—programs that optimize and provide the most benefits for our customers and grid services in conjunction with other renewable resources in our future portfolio.

Run production simulation with DER adoption levels. The four steps described above result in a forecast of DER adoption levels that is based on a) customer uptake of DER based on the economics from the customer's perspective, and b) provision of power supply and grid services from the customer that is cost effective from the overall system perspective.

These DER adoption levels are then included in a subsequent production simulation and financial model iteration and as DR potential in the DR iterative cycle (see next section for more details on the DR iterative cycle). The DER adoption levels will impact the net sales and peak forecasts (described in Chapter 4: Modeling Assumptions). If the retail electricity price and the value of DER substantially change in the production simulation and financial model, and in the DR modeling, then the above steps will be cycled through again. Through successive iterations as necessary, the quantities of DER will be optimized.

DEMAND RESPONSE (DR) ITERATIVE CYCLES

Though a component of DER, Demand Response requires a separate iterative cycle of resource planning and is made up of the following four steps:

1. Define required grid services.
2. Calculate quantities and the value of grid services.
3. Calculate DR amounts, costs, and system load shape impacts.
4. Run production simulations with DR amounts and load shape adjustments.

Define required grid services

The Companies have developed a portfolio of DR programs designed to deliver grid services that help meet their system security requirements. These grid services, having been defined in Docket No. 2007-0341, serve as the basis of all programs. Grid service definitions are cross-referenced with DR program attributes and rules to ensure that the means by which DR programs are defined allow for the effective delivery of the grid services by DR resources.

As part of the PSIP update, these service definitions and their associated equations are being modified (such modifications will be updated in the IDRPP when filed); an assessment of the degree to which these modifications impact the DR potential, and thus the overall DR portfolio, is the first step in the DR optimization process. In parallel, the

Companies will make any necessary adjustments to the market potential of the various DR programs.

Subsequent to the definition of grid services and the refinement of the potential study inputs the DR potential study model will be re-run utilizing the following modified and refined inputs:

- Updated load forecasts based on new resource plans.
- Adjusted "controllability" based on revised program attributes.
- Refined end use load shapes and associated "shedability."
- Modified "acceptability" percentages.[12]

Calculate quantities and the value of grid services

In order to identify the opportunities for potential DR resources to deliver grid services, DR optimization must first understand the quantities and value – or cost – of the various grid services for each time interval, for each island power system. To the extent feasible, demand response opportunities to provide each grid service will be evaluated independent from each other based on the results of the "Define required grid services" step.

Note that:

- Costs will not always be linear with quantity. For example, it may be necessary to provide a minimum amount of a particular grid service during a particular time interval in order to alleviate a must-run requirement and therefore realize value from a DR resource.
- The value of given grid service may be dependent upon that grid service being provided concurrently and in conjunction with other grid services. For example, the provision of the inertia grid service may be linked to the provision of primary frequency response (governor response), and the provision of spinning contingency reserve in order to alleviate a must-run requirement. This means that a DR resource that provides only a single grid service would have little value on a stand-alone basis and DR resources that provide multiple services will have greater value.

Under this step, the value of each grid service is calculated to provide insights as to how to best leverage demand response resources. Comparison of system production costs between model runs for adjusted service levels enables calculation of grid service values. More precisely, altering appropriate service requirements or constraints, relative to reference case, will result in differences in system costs that can be used to calculate

[12] Acceptability refers to the customers' willingness to "accept" a DR program opportunity; in other word, this represents the percentage of the eligible population that opts to enroll in a particular program.

incremental costs for delivery of that service. By understanding the relationship to quantity and value of services over time, it is possible to determine substitution opportunities for demand response products. Relaxation of must-run constraints will also allow us to infer value of inertia.

Calculate DR amounts, costs, and system load shape impacts

Once the quantities and values of grid services have been derived, an optimal DR portfolio will be developed and input into the production simulation model. An iterative process will derive both the population of end-use devices and the resulting DR "fit" for delivering grid services cost-effectively. The following sub-tasks represent this iterative process:

Preliminary inputs. Insert the following inputs required for the DR "fit" analysis: 1) The quantity and value of the services derived from DR Step 2 above: "Calculate quantities and value of grid services"; and, 2) The refined DR potential calculated during DR Step 1 above: "Define required grid services".

Identify DR portfolio "Fit". Determine the projected "fit" – and value - of DR products to meet some or all of each of the grid service needs, for each time step, for each island power system. Using an adaptive planning model developed by Black & Veatch expressly for our needs, optimize the provision of grid services from conventional resources and DR products to meet the power system reliability requirements at minimal overall cost. DR can provide a portion of the required grid services (see "Define Grid Services" section above) by displacing grid services provided by generating assets within an analysis case. These cost savings from DR can be in the form of capital deferment, avoided fixed costs, or avoided variable costs depending on whether the substitution is based on, changes in the timing of the expansion plan or size of an added resource, or changes in retirement timing, or changes in operation.

Within the adaptive planning model, the capability exists to reshape the DR programs on a day-to-day basis to address different daily changes in demand, wind and solar profiles, and the availability of assets. This enables the model to calculate the "stack" of DR resource utilization such that DR resources are allocated among the programs in a way that maximizes the value of the DR portfolio. This capability allows the Companies to assess the "fit" of the adaptive planning model results against system security needs and the underlying asset portfolio characteristics.

This preliminary investigation of the appropriate DR "fit" will be followed by a sensitivity analysis, the purpose of which is to expose areas of concern where changes in the electric system can substantially impact the value of DR services. These sensitivities include:

- Availability, size and cost of storage.
- Role of DR products given modified security constraints[13].

Given that the adaptive planning model directly calculates value in moving underlying end uses between DR programs, the resulting "fit" is generally optimized at this point against security and system asset characteristics. In cases where the value does not seem reasonable, further investigation may be needed to ascertain validity of results, or to identify gaps where additional DR products could help meet system response requirements and/or reduce renewables curtailment.

Derive value of bundled services for storage only / derive value of real time pricing (RTP) only (that is, for DG-PV + storage). Based on the initial "fit" evaluation, develop annual values associated with bundles of grid services that may be delivered by a stand-alone storage device; this value serves as a proxy for the annual economic value that can be earned with stand-alone DESS. In addition, develop an annual value of the TOU and RTP programs. This will serve as a proxy for economic value for DG-PV + Storage systems. Values will be provided for the 2017–2045 timeframe.

Load shifting can be accomplished with pricing, storage, and behavioral tools (for example, demand response) in addition to utility-scale and grid solutions. We will address these issues in our Updated PSIPs.

Forecast customer adoption. The value that a standalone DESS or DG-PV + storage system provides by participating in a DR program is included as a revenue stream in calculating customer payback and the associated adoption of DESS and DG-PV + storage systems.

Refine populations and potential. Insert the forecasted customer adoption for DESS and DG-PV + storage into the potential study model. A revised DR potential is then recalculated based on the updated populations.

Rerun DR portfolio "Fit". The new DR portfolio potential is then used to determine the DR "fit" and corresponding value of the DR services. The DESS and DG-PV + storage values are compared to the values previously calculated. If the values of standalone DESS and DG-PV + storage are essentially consistent with the previous run, no additional work is required, because the convergence of the two values reflects an optimal population of the

[13] The adaptive cost model can employ revised system security requirements to evaluate their impact on the opportunity for DR to deliver grid services, but the model cannot evaluate the security viability of these modifications. While they may present additional cost avoidance opportunities, they may also introduce additional system risk.

end uses and the DR portfolio as a whole, for that particular case. If the values are meaningfully different, then customer adoption is re-forecasted.

Iterate until convergence of values. If convergence of the economic value of DR, DESS and PV + storage occurs, then the process is complete; however, if there are variances in those economic values, the process will continue until subsequent DR "fit" runs result in convergent sets of economic values, at which point the populations and the DR portfolio are determined to be sufficiently optimized, for that particular case.

Finalize the DR portfolio. Once convergence is achieved, the DR optimized portfolio will be finalized and used in the production simulation. For each case, these results will be presented as a combination of:

- Effective impact on the system load shape by year for the entire DR portfolio. As DR is intended to manipulate demand in order to deliver grid service, an optimized portfolio ultimately takes the form of impacts on system load shapes.
- Annual costs of the portfolio for the entire 2017 - 2045 timeframe.
- Any material adjustments made to the resource plans resulting from the DR optimization effort. Changes may include resizing of resources, shifting of retirement schedules and deferral of capital investments/shifting in the timing of procurement.

Run production simulations with DR amount and load shape adjustments

The optimized DR portfolio will be passed to the production simulation modeling teams as a model input. Portfolio costs as well as any cost impacts related to resource plan adjustments will be added to the economic evaluation of each resource plan case.

UTILITY-SCALE RESOURCES ITERATIVE CYCLE

The utility-scale resource iterative cycle is similar to those used for DER and DR. The following steps are employed:

Identify high impact variables. Variables that have a high impact on the Objectives are identified. For the initial (not yet optimal) runs in the interim PSIP update filing, fuel type, extent of generation modernization, and amount of DER adoption were identified as high impact variables. In subsequent runs, based on previous results, new high impact variables may be identified for focus in the cases.

Develop and refine analysis cases. Considering high impact variables and the results of the DER and DR iterative cycles, analysis cases are developed to understand the impact on the Objectives of the identified high impact variables. For example, if fuel is identified as a high impact variable, one case may assume, as a transition to a 100% RPS, a low forecast of LNG prices, whereas another case may assume there is no LNG and oil as the primary fuel source. Outputs from the DR iterative cycle, including DR amounts, costs, and system load shape impacts are also incorporated into the cases that will be run in the production simulation.

Analyze forecast resource cost and availability. This step determines near-optimal resource quantity and timing. The production simulation and financial rate modeling determine, at a very detailed level, generation output and associated rate impact for a given case. Multiple cases are compared, revised, and successively iterated until a plan is identified that best meets the Objectives. To make this iterative process more efficient, resource cost forecasts are analyzed outside of the production simulation to identify likely near-optimal resource quantity and timing for the various analysis cases. More specifically, lowest cost resources are deployed first, subject to appropriate constraints. So, for example, in the initial run for O'ahu in the PSIP Update Interim Status Report, utility-scale wind and solar were identified as low cost resources, and so deployed up to their maximum potential (before hitting land constraints) in the analysis cases.

Run production simulations. Analyze cases and near-optimal resource quantity and timing. Once analysis cases have been developed to test high impact variables and near-optimal resource mixes have been incorporated into the cases, the production simulations of cases are performed to calculate generation for each resource through the use of hourly and sub-hourly unit commitment and economic dispatch algorithms. Production outputs are then used to determine total costs to the system and customer rate impacts that considers the capital cost, fuel costs, fixed O&M and variable O&M related for the operation of the electric system over the planning period. Results are analyzed, and the above steps are iterated through multiple times until a plan is identified that best meets the Objectives.

Verify system security compliance. Through transient stability analysis, each case will be checked for adequate system stability for critical commitment schedules and dispatch levels when subjected to various contingency conditions. If system security requirements are not met, technology neutral system requirements will be determined and adjustments made. Regarding system security, it's important to note that some generating units need to be committed and/or dispatch outside of ideal economic dispatch until technology neutral alternatives are added to the grid or until the driving contingency event(s) can be eliminated. At some point in time when DR and DER resources are available in sufficient capacities, must-run units for system security will not constrain resource plans.

MODELING TOOLS

Our Resource Planning Department uses a well-established modeling tool to run our analyses for the Updated PSIPs. In addition, we have contracted with a number of consultants to use their own modeling tools (in some cases, proprietary tools developed solely for the PSIPs).

These modeling tools and the team running the tool include:

- Siemens PTI PSS®E for System Security Analysis: Hawaiian Electric Transmission Planning Division
- P-MONTH Modeling Analysis Methods: Hawaiian Electric System Planning Department
- Adaptive Planning for Production Simulation: Black and Veatch
- DG-PV Adoption Model: Boston Consulting Group
- Customer Energy Storage System Adoption Model: Boston Consulting Group
- Grid Defection Model: Boston Consulting Group
- PowerSimm Planner: Ascend Analytics
- Long-Term Case Development and RESOLVE: Energy and Environmental Economics (E3)
- PLEXOS® for Power Systems: Energy Exemplar
- Financial Forecast and Rate Impact Model: PA Consulting

Appendix C: Analytical Models contains detailed descriptions about each of these tools.

Resource planning, however, is much more than running models. The true proficiency in resource planning derives from expert analyses and interpretation of the results, then applying those results to our unique island power systems.

4. Modeling Assumptions

This chapter presents an overview of the modeling assumptions employed in our ongoing analyses.[14]

CHANGES IN CIRCUMSTANCES

Here are just a few of the many significant developments that have transpired over the past 18 months since the 2014 PSIPs were filed.[15]

- Passage of Act 97, extending a 40% RPS target in 2030 to a 100% RPS in 2045.
- Dramatic decline in the price of fuel oil by more than 75%, creating uncertainty in forecasted costs.
- The end of the NEM program and concurrent creation of two new replacement programs: grid supply and self supply.
- Valuable ongoing experience with increasing levels of DG-PV, including from the testing and installation of advanced inverters.

Taken all together, these changes have created a vastly different environment for energy planning. These changes perhaps harken comparable changes over the next eighteen months as well. Because of this continued dynamic environment, we strive to build flexibility into our resource planning. This PSIP Update Interim Status Report represents our sincere effort to consider these developments while recognizing that more changes are certain to follow.

[14] Additional details and data for these assumptions is available in Appendix D: Modeling Assumptions Data.

[15] In addition, on February 12, 2016, Hawaiian Electric terminated three PPAs for utility-scale PV projects totaling 109.6 MW for non-compliance with the terms of the PPAs.

OVERVIEW OF OUR MODELING ASSUMPTIONS

For the 2016 updated PSIP analyses, we have reevaluated virtually every assumption used as input for our analyses. These assumptions include, but are not limited to:

- Planned changes to our generating resources
- Available resource options and their costs
- LNG as transitional fuel source
- Utility-scale energy storage resources and their costs
- Distributed Energy Resources cost assumptions
- Demand and energy sales forecasts
- Fuel price forecasts and availability
- Inter-island cable assumptions
- System operating and reliability criteria

Provided here is an overview of the assumptions. Appendix D: Modeling Assumptions and Derivations explains how we developed these assumptions. Appendix A: Modeling Assumptions Data contains tables of the actual data used in our analyses.

While we have used these assumptions in our analyses to date, they are still preliminary. Based on further analysis, however, some of these assumptions could change while others might be added. Our Updated PSIPs will present the definitive list.

PLANNED CHANGES TO OUR GENERATING RESOURCES

Existing Generating Units

Waiau 3 and Waiau 4. The 2016 PSIP analysis assumes that Waiau 3 and Waiau 4 will be deactivated at the end of 2017, however actual deactivation plans will consider the needs of adequacy of supply.

Honolulu 8 and Honolulu 9. The 2016 PSIP analysis assumes that Honolulu 8 and Honolulu 9 remain deactivated.

Maui Electric. The 2016 PSIP analysis assumes that all units on Molokaʻi and Lanaʻi are active and operating. On Maui, Kahului 1 and 2 are currently deactivated but are counted toward firm capacity since they can, and occasionally are, reactivated when needed to maintain system reliability. The 2016 PSIP assumes that the Kahului Power Plant will be retired in 2022.

Hawaiʻi Electric Light. Shipman 3 and Shipman 4 were retired at the end of 2015, and the 2016 PSIP analysis assumes that.

Kahe Combined Cycle

In the PSIPs, Hawaiian Electric is considering a modern, state of the art, highly fuel efficient, operationally flexible, 383 MW, 3x1 combined cycle unit located on Hawaiian Electric ʼs existing property at the Kahe Generating Station. The Kahe Combined Cycle (Kahe CC) would encompass approximately 15 acres at the Kahe property and could have an in-service date of June 2021. The Kahe CC would be capable of operation using LNG, fuel oil, a mix of the fuels or even biofuel. Kahe CC would replace low sulfur fuel oil burning Kahe Units 1, 2, and 3 (270 MW capacity), which would be retired in 2020 in combination with the construction of the Kahe CC.

The Kahe CC could be a 3x1 CC unit consisting of three nominal 77 MW General Electric 6FA.03 combustion turbines (CT) and three heat recovery steam generators (HRSG), which would use the waste heat from the CTs to produce steam to be utilized in a new steam turbine generator. Kahe CC's base capacity would be 358 MW. For additional power production, the facility could be capable of utilizing wet compression technology during peak demand periods to add about 25 MW of capacity to the unit, totaling 383 MW. The unit's base heat rate would be 6,965 Btu/kWh at an average ambient temperature of 86° F. The unit would have an estimated average forced outage factor of approximately 1.6%, a planned outage factor of 2.0% and an equivalent availability factor of 96.4%. The rate at which the unit would be able to change load is 35 MW/min, as compared to 13 MW/min for the Kahe 1–3 steam units (combined) designated for replacement.

To preclude the likelihood that a single contingency event would result in a loss of generation greater than 145 MW, the Kahe CC would be designed with the capability of bypassing the steam turbine. This same design feature would allow for fast startup and full loading of the three combustion turbines (17 minutes to baseload) while the steam turbine is more slowly brought on line (44 minutes to full load). Additionally, a dump condenser would be part of the design, which would allow for the steam turbine and its main condenser to be taken off line for maintenance while still allowing for full operation of the three combustion turbines.

The project would be located at the Kahe Generating Station in a portion of the currently unused valley to the north of the existing units at an elevation that puts it outside the tsunami inundation zone. This location would allow Hawaiian Electric to take advantage of the following existing major infrastructure, thereby significantly reducing the project cost.

- Cooling Water Intake
- Cooling Water Discharge
- Liquid Fuel Tanks and Pipeline
- Demineralized Water
- 138kV Substation
- Maintenance Facilities

The Kahe CC would have the unique advantages of being able to utilize existing cooling water systems and transmission infrastructure at the Kahe Generating Station site. Due to system reliability requirements, the older units replaced by the Kahe CC would need to remain in service during the initial construction period of the Kahe CC. At a point in the construction of the Kahe CC, the existing units would need to be shut down and certain critical services such as the transmission and cooling water systems for those units would be integrated into the new CC unit. The interface and coordination required to allow a third party to perform construction on the site of an existing operating plant and then integrate portions of the existing facility into the new CC unit would extend the construction schedule (and add cost) to the finished project as compared to the utility performing all of this interface.

Military Base Microgrids

Hawaiian Electric will be seeking replacement generating capacity for the island of O‘ahu as the AES contract expires, existing power plants reach retirement age and as new flexible (and efficient) generation technology becomes necessary to integrate large amounts of as-available energy resources on the island grid. The Marine Corps and the Navy are seeking enhanced energy security for their bases and to the extent that this can be accomplished without significant capital investment by the Department of Defense (DoD), they are interested in partnering with Hawaiian Electric to do so. There are potential synergies to these needs that could be aligned to develop mutually beneficial solutions to the benefit of all O‘ahu customers.

The Air Force has similar goals and requirements. Because of the consolidation of Hickam Air Force Base and Naval Base Pearl Harbor into JBPHH (which is administered by the Navy), meeting the Navy's goals for JBPHH will also satisfy the Air Force's goals.

Hawaiian Electric's goals include:

- Satisfying our customers' needs for cost-effective energy solutions, including the DoD's energy security needs.
- Developing new flexible generating assets that can respond to the variability of as-available energy resources (for example, PV and wind power), thus enabling higher penetration levels of those variable resources.
- Enhancing the company's ability to meet the 100% RPS goals by investing in technologies that are capable of using renewable fuels (that is, biofuels).
- Improving island-wide energy resiliency, which includes fuel flexibility and smaller, more geographically dispersed generators.
- Improving grid-wide efficiency.
- Improving the response capability of First Responders in an island-wide emergency such as a natural disaster.
- Leveraging low cost, limited use lands for which existing zoning will allow for installation of new generation to minimize development costs.
- Seeking Military service funding to execute National Environmental Policy Act (NEPA) Environmental Impact Statement (EIS) process, to demonstrate service commitment to project.

Hawaiian Electric understands the DoD's goals to include:

- Enhanced energy security and resiliency for its bases, including Marine Corps Base Hawai‘i (MCBH) and JBPHH, while minimizing capital costs by leveraging public-private partnerships with utilities.
- Added opportunities to increase renewable energy generation on DoD installations.
- Reduced energy costs.

Marine Corps Base Hawai'i (MCBH) Microgrid Concept

To provide the services desired by the Marine Corps, Hawaiian Electric and the Marines have discussed a microgrid project at MCBH whereby Hawaiian Electric would lease the project site at little to no cost for the life of the project and design, permit, finance, construct, own, and operate a new, up to 54 MW firm generating station located on the site. This is a resource option for O'ahu in the interim PSIP updates.

Joint Base Pearl Harbor–Hickam (JBPHH) Microgrid Concept

To provide the services desired by the Navy, two concepts are being considered: 1) locating a microgrid on base at JBPHH with capacity of approximately 90 MW; or 2) installing a power barge at the Waiau Generating Station that could either be interconnected to JBPHH or temporarily relocated to JBPHH under emergency conditions. The power barge capacity is approximately 100 MW. These are resource options for O'ahu in the PSIPs.

Status of Independent Power Producers and PPAs

Since we filed our PSIPs in 2014, we have experienced a change in status or assumptions related to some of the independent power producers (IPPs): AES Hawai'i, Kalaeloa Energy Partners (KPLP), Hamakua Energy Partners (HEP), Hu Honua, and Hawaiian Commercial & Sugar (HC&S). We have also updated our plans for modifying existing units to burn gas (as well as oil and biofuels), and changed operations to comply with environmental requirements.

AES Hawai'i Generating Unit. The 2016 Updated PSIP analysis assumes that our power purchase agreement (PPA) with AES Hawai'i will not be renewed when it expires on September 1, 2022. Our ability to integrate more renewable generation onto the grid in the coming decades will be improved without a large, inflexible single generator such as AES on the system. The unit provides relatively little ancillary services to the system. Under the current PPA, AES provides a large block of coal-fired generation that Hawaiian Electric must accept. Without this constraint, more renewable energy can more easily be integrated onto the system.

Kalaeloa Energy Partners (KPLP). The Kalaeloa Plant's combined cycle design has the operational flexibility required to support the needs of the renewable fleet. However, the existing PPA for the Kalaeloa Plant is restrictive; it does not allow the Companies to operate the plant with the flexibility that will be required in the future. Development of alternatives to remove these restrictions is ongoing and could result in several alternatives for consideration in the Updated PSIPs.

The interim PSIP updates assumes the same operational flexibility of the KPLP plant after the end of the existing PPA. This assumption, however, could change after filing this PSIP Update Interim Status Report.

Hamakua Energy Partners (HEP). Hawai'i Electric Light has submitted an application to the Commission to purchases the 60 MW dual fuel combined cycle HEP plant from its current owners, thus buying out an existing PPA at a lower cost to customers. However, for the purposes of production modeling and financial analysis in the Interim PSIP Update, HEP is modeled as an IPP plant with economics and operating parameters based on the current PPA.

Hu Honua. Hu Honua is the next planned renewable energy resource addition on the Hawai'i Electric Light system. However, Hu Honua has missed major project milestones under the terms of its PPA. As a contingency plan and in order to evaluate resource options, the interim PSIP update analysis does not assume Hu Honua as being available.

Hawai'i Island Geothermal Request for Proposal (RFP). Because the selected bidder in the February 2013 geothermal RFP has decided not to proceed with contract negotiation, our analysis does not assume additional Hawai'i Island geothermal as a generating option.

Hawaiian Commercial & Sugar (HC&S) Closure. The Maui Electric analysis assumes HC&S contributing 4 MW of firm capacity in 2016, and no generation in 2017 and beyond.

Environmental Considerations

Updated Mercury Air Toxic Standards (MATS) and National Ambient Air Quality Standards (NAAQS) requirements directly affect Hawaiian Electric steam generating units. Appendix D provides a complete discussion of environmental considerations.

LNG as a Transitional Bridge Fuel

The Rationale for Adopting LNG as a Transitional Bridge Fuel

We have highlighted the need for modernized generation in order to optimize costs, reduce emissions and facilitate the increased integration of variable renewable resources by utilizing flexible, modernized generation resources. Even with these new resources in place however, the Companies current fuel source for its dispatchable generation during the transition period to a 100% RPS will be petroleum-based fuels. As a result, customers will be exposed to a fuel which is:

- High cost and significantly volatile in price

- Subject to increasing restrictions under tightening federal environmental standards

Specifically, the modernized fleet would consume the equivalent of an average of 7.8 million barrels of oil per year through the end of 2040, at which point a conversion to biodiesel is contemplated.

With the adoption of LNG as a transition fuel, Hawaiian Electric sees an opportunity to both lower the cost to its customers and accelerate the reduction in emissions. An LNG plan has been designed specifically as a transition solution for Hawai'i. It seeks to limit the amount of permanent island infrastructure investment as well as the associated capital spending. Furthermore, having the ability to remarket excess LNG will reduce the risk for potential variability in the demand for LNG as the integration of renewable resources increases. Hawaiian Electric does not view LNG as substituting for, or competing with, new renewable resources on the islands. Rather LNG represents a complementary solution which can help achieve the Companies' goals of keeping costs to the customers as low as possible while mitigating impacts to the environment. LNG represents a good value proposition to customers under a wide range of potential renewable penetration scenarios, especially when combined with the flexible, efficient, modernized generation described in the previous section.

Overview of the LNG Delivery System

In evaluating an LNG delivery solution for Hawai'i, the Companies looked at (1) land based LNG import terminals and (2) Floating Storage and Regasification Units (FSRU), both of which entailed installation of permanent infrastructure on and offshore, new gas pipelines, high per unit costs and long permitting processes. The Companies opted to issue a request for proposal (RFP) for a containerized LNG solution to land LNG in Hawai'i and distribute it to its generation fleet across the State. This solution would use International Standards Organization (ISO) containers to locally transport LNG, which are standardized metal vessels that can be loaded and transported on a conventional truck, to maximize flexibility and reduce requirements for dedicated land infrastructure.

A possible LNG supply chain would consist of the following components:

- Natural gas sourced from some of the most prolific gas reserves located in Northeast British Columbia. The gas would be transported from the gas reserves to Fortis BC's Tilsbury liquefaction plant on the Fraser River by pipeline where it would be liquefied.
- The LNG would be loaded onboard a ship for transport to Hawai'i. Upon arrival in Hawai'i, the LNG would be delivered in ISO containers to the point of use on O'ahu, Maui, and Hawai'i Island.
- Multiple ships will be employed to ensure a steady rate of LNG delivery for use at the various generating stations.

The containerized supply chain was selected as the option with the greatest congruence with the evaluation criteria set forth by the Companies.

Scalable, Transitional with Minimal Onshore and Offshore Impact: The use of containers provides a number of significant benefits relating to this criterion: (i) no pipelines need to be built either at the receiving point or to the power plants minimizing onshore impacts and permitting requirements that could cause project delays (both FSRU and LNG terminal options need new pipelines), and (ii) ability to remarket excess LNG improves downward scalability should renewable integration be greater than expected.

Neighbor Island Coverage: The use of the ISO container model easily accommodates supply to the Neighbor Islands.

Minimal Permitting: Because no permanent facilities would be deployed in the supply chain, no FERC approval would likely be required. This compares favorably to both an FSRU and an LNG terminal where a FERC permit is required, which can be a lengthy and expensive process. No pipeline construction allows for minimal on-island impact.

Security of Supply/Gas versus Oil-Indexed Pricing: Sourcing natural gas from Canada avoids the risk of sourcing from more politically unstable locations. The supply contract would source natural gas from markets in British Columbia, Canada, which is among the most prolific and lowest priced gas supply basins in the world. It compares very favorably to the Marcellus shale region in Pennsylvania. It is expected that the cost per one million British thermal units (MMBtu) from British Columbia will be less than the cost of LNG indexed to crude oil.

Ability to Serve Other Customers in Hawai'i: The supply system will have capacity in excess of Hawaiian Electric's initial requirements by roughly 10%. This excess amounts to approximately 4 million MMBtu per year. This allows the supplier to make additional sales to other customers using the Hawai'i supply chain, thus extending the benefits of LNG to other Companies on the Islands.

Overview of the LNG Plan

Under a merged scenario between the Hawaiian Electric Companies and NextEra, Hawaiian Electric could seek to enter into an agreement to acquire approximately 800,000 metric tons of LNG from the Fortis LNG facility. Deliveries could start in 2021 and coincide with the commencement of commercial operations of modernized combined cycle units at Kahe. In addition to the modernized plants, the Companies would modify five of their existing generation units (six including Hamakua if approved by the Commission) to allow them to use LNG in addition to oil-based fuels. This involves installation of new equipment to receive, store and regasify the LNG, and adaptation of the existing generating units to allow for gas utilization (with total estimated cost of the conversions at approximately $340 million). It is assumed that the two combustion turbines at the KPLP Generating Station would also be modified to use LNG.

After the completion of the modernization and conversions, Hawaiian Electric would have approximately 1,100 MW of generation capacity capable of using LNG-based fuel for a period of transitioning to a 100% RPS (as outlined in Table 4-5):

O'ahu			
Unit Name	*New or Existing*	*Nominal Unit Capacity*	*Unit Ownership*
Kahe 5	Existing	140 MW	Hawaiian Electric
Kahe 6	Existing	140 MW	Hawaiian Electric
Kalaeloa	Existing	208 MW	IPP
Kahe Replacement Generation	New	383 MW	Hawaiian Electric
Maui			
Unit Name	*New or Existing*	*Nominal Unit Capacity*	*Unit Ownership*
Ma'alaea 14/15/16	Existing	58 MW	Maui Electric
Ma'alaea 17/18/19	Existing	58 MW	Maui Electric
Hawai'i Island			
Unit Name	*New or Existing*	*Nominal Unit Capacity*	*Unit Ownership*
Keahole 4/5/6	Existing	60 MW	Hawai'i Electric Light
Hamakua	Existing	60 MW	(TBD)

Table 4-5. Unit Modifications for LNG

Customer Savings from Utilizing LNG as a Transitional Bridge Fuel

The ultimate savings realized by customers from an LNG solution would vary with actual realized commodity prices over a 20-year period and are therefore impossible to exactly predict. The Companies performed an analysis using the Energy Information Administration's (EIA) forecasts for crude oil and gas, accounting for the costs of delivery for the LNG and oil based fuels. This analysis estimates total customer accumulated present value revenue requirement savings of between $352 million and $3.5 Billion from the utilization of LNG, assuming implementation of the modernized generation fleet outlined in the previous section.

An additional benefit of using LNG is that it reduces the volatility of the delivered cost of the fuel, and therefore volatility in the customer's overall bill, relative to oil-based fuels. This is due in large part to the fact that the underlying commodity price makes up a smaller portion of the delivered cost of LNG relative to oil based fuel. The difference in the resulting variability of the delivered fuel price is illustrated in Figure 4-4.

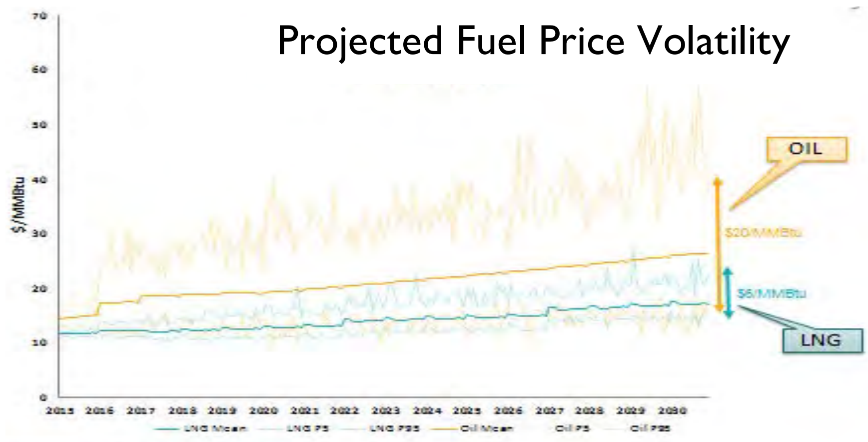

Figure 4-4. Projected Fuel Price Volatility

Environmental Impact

A key driver of Hawai'i's vision of a 100% renewable solution is the desire to reduce emissions from its power generation portfolio. Since a 100% renewable solution will take time to transition to, LNG offers an opportunity to significantly reduce emissions during the transition period. Table 4-6 highlights the expected reduction in emissions in 2023, the first full year of possible LNG service as measured against the Reference Case (Case 1) values in 2016: as well as over the life of an LNG contract.

	SO2 tons	NOx tons	PM tons	CO2 tons
2016 Reference Case (Case 1)	18.0 k	21.9 k	5.2 k	7.9 Mil
2023 LNG Only (Case 3)	5.1 k	14.4 k	0.9 k	4.1 Mil
Difference	12.9 k	7.5 k	4.3 k	3.8 Mil
Difference (%)	72%	34%	83%	48%

Table 4-6. Emission Rates of Existing Fleet versus Replacement Generation in 2023

In addition, new environmental compliance requirements, most notably the EPA's NAAQS, have focused our attention on finding the best, most cost-effective means to achieve compliance. The Companies view LNG as a viable alternative to petroleum fuels in that it will enable the Companies to meet or exceed the more stringent air emission standards of both the Environmental Protection Agency's MATS and NAAQS, while substantially lowering fuel costs.

DEMAND AND ENERGY SALES FORECASTS

The purpose of the load (or peak demand) and sales (energy) forecasts in a planning study is to provide the energy requirements (in GWh) and peak demands (in MW) that must be served by the Companies during the planning study period. Forecasts of energy requirements and peak demand must take into account economic trends and projections and changing end uses, including the emergence of new technologies.

The forecast presented in Appendix A and Appendix D is the beginning of an iterative process that will determine varying levels of customer adoption of DER, including participation in DR programs to achieve system optimization. Appendix D includes a discussion of the derivation of load and energy forecasts, and its iterative nature given the resource optimization process.

FUEL PRICE FORECASTS AND AVAILABILITY

The potential cost of producing electricity will depend, in part, on the cost of fuels utilized in the generation of power. The cost of different fuels over the next 20-plus years are forecast and used in the PSIP analyses. The Companies use the following different types of fuels in our company-owned generators:

- No.2 Diesel Oil
- Low Sulfur Fuel Oil (LSFO). A residual fuel oil similar to No. 6 fuel oil that contains less than 5,000 parts per million of sulfur; about 0.5% sulfur content.
- Ultra Low Sulfur Diesel (ULSD)
- Naphtha
- Medium Sulfur Fuel Oil (MSFO containing less than 2% sulfur)
- Biodiesel

LNG Price Forecasts

Two forecasts were developed to correlate to the two forecasts developed for petroleum-based fuels: U.S. Energy Information Administration (EIA) and Forward/Hybrid Chicago Mercantile Exchange (CME) gas futures. For EIA, the 2015 EIA average Henry Hub spot prices for natural gas (2013 dollars per million Btu) Reference was adjusted from 2013 dollars to nominal dollars. For CME, we pulled the CME Henry Hub Gas Futures settle prices from February 1, 2016, averaged the monthly prices from March 2016 through December 2028 over the 12 month period to derive annual prices from 2016 through 2028, then applied an escalation factor for 2029 to 2040. LNG liquefaction and transport costs were developed using estimates derived from the Companies Containerized LNG Supply to Hawai'i RFP.

Petroleum-Based Fuels

In general, we derive petroleum-based fuel forecasts by applying the relationship between historical crude oil commodity prices and historical fuel purchase prices to forecasts for the crude oil commodity price. The petroleum-based fuel forecasts reflect EIA forecast data for Imported Crude Oil and Gross Domestic Product (GDP) Chain-Type Price Index from the 2015 Annual Energy Outlook (AEO2015) year-by-year tables. Historical prices for crude oil are EIA publication table data for the Monthly Energy Review and macroeconomic data. Historical actual fuel costs incorporate taxes and certain fuel-related and fuel-handling costs including but not limited to trucking and ocean transport, petroleum inspection, and terminalling fees.

When the AEO2015 was published in April 2015 Brent crude oil was approximately $60 a barrel. Over the remainder of 2015 Brent crude oil continued to drop to below $40 per barrel at the end of 2015, which is below the AEO2015 low economic growth case which estimated 2016 Brent crude oil at over $50 per barrel. Since the 2016 Annual Energy Outlook (AEO2016) update from the EIA is not expected until June 2016 and Brent crude oil was already below the AEO2016 low economic growth case, we generated a Forward/Hybrid pricing curve that is expected to be between the AEO2016 reference and low economic growth cases. To generate this curve, data was taken from CME Group[16] for Brent crude oil futures from 2016-2023 and scaled with factors from the AEO2015 to develop a Brent crude oil pricing curve that starts near current Brent pricing and escalates similarly as the AEO2015 low growth case of Brent crude oil. The same correlation is then applied to the generated Brent crude oil that was applied to the AEO2015 Brent Crude oil. If current Brent pricing was not below the AEO2015 low economic growth, then the AE2015 low economic growth case would have been used.

It might be necessary to utilize a fuel blend of 70% LSFO and 30% diesel in Kahe 5 and Kahe 6 for 2016–2024 and then a fuel blend of 40% LSFO and 60% ultra low sulfur diesel in all steam units starting in 2025 for purposes of environmental compliance.

Biodiesel

Biodiesel forecasts are generally derived by comparing commodity forecasts with recent biofuel contracts and RFP bids to determine adjustments needed to derive each company's respective biodiesel price forecast from forecasted commodities. EIA provides low, reference, and high petroleum forecasts, which are used to project low, reference, and high petroleum-based fuel price forecasts. A similar commodity forecast has not

[16] http://www.cmegroup.com/trading/energy/crude-oil/brent-crude-oil-last-day.html.

been found for biodiesel, although EIA might provide one in the future. In lieu of such a source, the biodiesel forecast is based on the Food and Agricultural Policy Institute at the University of Missouri (FAPRI) forecast of biodiesel prices in the United States.

While the EIA forecast provides petroleum prices through 2040, FAPRI provides biodiesel pricing through 2024 and then that trend is extrapolated by Hawaiian Electric out to 2045. The EIA forecast trend is also extrapolated from 2040-2045. As a result of extending both forecasts beyond their provided period, errata might be introduced into the analysis for later years, especially when the two trend lines cross during the period of time that both are extrapolated. The extrapolated forecast results in an unlikely case in which biodiesel prices fall below oil prices in later years. The extended forecast for biodiesel is being reevaluated and will be included in our Updated PSIPs.

AVAILABLE RESOURCE OPTIONS AND THEIR COSTS

Specific PSIP Assumptions Related to New Utility-Scale Resources

The specific assumptions regarding new utility-scale generating resources are contained in Appendix A of this filing. The derivations and development of the various resource options considered are discussed in Appendix D. One of the key differences from our 2014 PSIP assumptions is the incorporation of forward curves for the capital cost of new generating technologies and new energy storage technologies. Figure 4-1 is a graph showing the projections of per unit capital costs (expressed in $/KW) in constant 2016 $. The data portrayed in Figure 4-5 are the underlying constant $ projections that underlie the nominal dollar assumptions utilized in the interim PSIP updated analysis. The constant dollar projection is a useful way to portray the expected future cost trends of various electric power generation technologies.

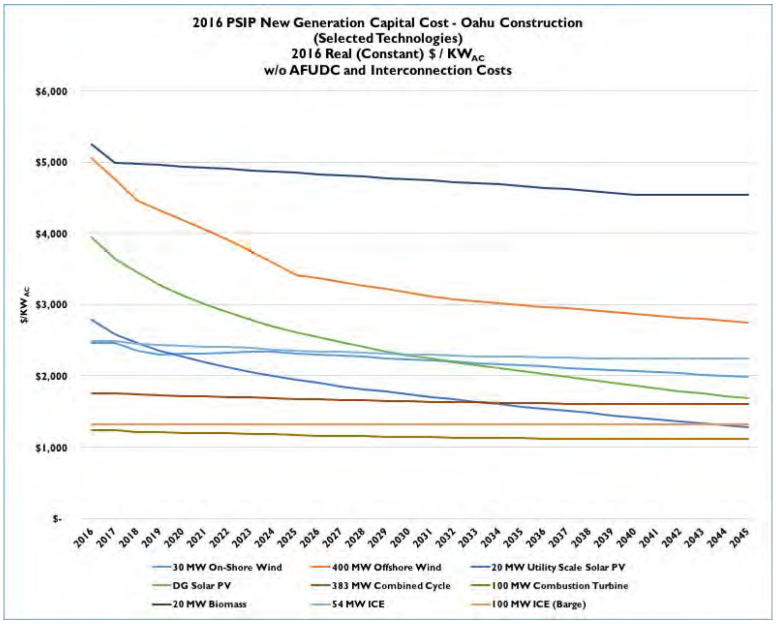

Figure 4-5. 2016 PSIP Utility-Scale Generating Resource Capital Costs

Constraints on New Utility-Scale Resources

In Order No. 33320, the Commission expressed concern that the constraints on resources by island were "unsubstantiated."[17] We acknowledge that an accurate and realistic estimate of the incremental resource potential, particularly on O'ahu, is very important in light of Hawai'i Act 97 providing for the 100% RPS. To the extent that there are significant constraints on O'ahu, the strategic need to consider off-island options (for example, offshore wind, and inter-island transmission) becomes greater.

In order to address this important question, the Companies have retained NREL to perform an analysis of the "developable" wind and solar energy on O'ahu, Maui, and Hawai'i Island.

In order to address this important question, the Companies have retained NREL to perform an analysis of the "developable" potential on O'ahu, Maui and Hawai'i Island. The results of the NREL analyses, received as this interim report was being finalized, were not available to us in time to incorporate them into our interim analysis. Accordingly, we performed own analysis using publicly available sources and determined that reasonable assumptions are 100 MW of additional wind and 715 MW of additional solar PV for O'ahu. Refer to Appendix D for a discussion of our methodology.

[17] Order No. 33320, Concern 2.c. at 84.

Table 4-7 shows the preliminary results of the NREL analysis regarding the potential for new wind and solar resource potential by island—the numbers are total resource potential, including projects already developed and operating

the total resource potential including existing resources. These results indicate that while the neighbor islands have substantial "developable" resource potential, O'ahu is reaching its limits with respect to additional wind resources. With respect to utility-scale solar PV potential on O'ahu, there is still some resource potential, if it is possible to develop solar PV on lands with slopes greater than 3%. However, development on steeper slopes will tend to increase project costs.

Preliminary Results of NREL's Island Resource Potential Study				
Resource	*Exclusion Criteria*	*O'ahu*	*Hawai'i*	*Maui*
Utility-Scale PV	Excludes capacity factor potential less than 20%, Excludes all areas with slope greater than 5%	621 MW	45,951 MW	1,666 MW
Utility-Scale PV	Excludes capacity factor potential less than 20%, Excludes all areas with slope greater than 3%	0 MW	3,704 MW	0 MW
Utility-Scale Wind	Excludes all areas with wind speeds less than 6.5 meters / second at 80 meters high	174 MW	3,276 MW	698 MW

Table 4-7. Preliminary Results of NREL's Island Resource Potential Study

Utility-Scale Resource Options by Island Available for the 2016 PSIP Analysis

Table 4-8 summarizes the PSIP utility-scale resource options assumptions that the planning teams used at this time for development of long-term power resource plans. These assumptions are preliminary and could change based on further analysis.

Resource Type	PSIP Assumed Project Block Sizes by Technology			
	O'ahu	Maui	Moloka'i and Lana'i	Hawai'i Island
Solar PV	20 MW	1 MW, 5 MW, 10 MW, 20 MW	1 MW	1 MW, 5 MW, 10 MW, 20 MW
Onshore Wind	30 MW	10 MW, 20 MW, 30 MW	Research Pending	10 MW, 20 MW, 30 MW
Combustion Turbines	100 MW	20.5 MW	n/a*	20.5 MW
Combined-Cycle	152 MW 1 x 1, 383 MW 3 x 1	n/a	n/a	n/a
Internal Combustion Engines	27 MW (3 x 9 MW), 54 MW (6 x 9 MW), 100 MW (6 x 16.8 MW)	9 MW	1 MW	9 MW
Geothermal	n/a	20 MW†	n/a	20 MW
Biomass	20 MW	20 MW	1 MW	20 MW
Resource Technologies For Possible Evaluation in Sensitivities				
Waste-to-Energy (WTE)	n/a	10 MW	1 MW	10 MW
Offshore Wind	400 MW	n/a	n/a	n/a
Off-Island Wind + Cable	200 MW, 400 MW	n/a	n/a	n/a
Solar CSP w/10 hours storage	100 MW	n/a	n/a	n/a

* A small CT was not considered for Moloka'i and Lana'i as their efficiencies are far less than those of an ICE unit of the same size.

† The geothermal option availability for Maui is limited to post 2030 in the 2016 PSIP update analysis.

Table 4-8. Preliminary New Utility-Scale Resource Options in the 2016 PSIP Analyses

Comments on Table 4-8:

- At the time of this filing, we are researching viable small wind technologies which might cost effectively compete with other technologies. The deployment of a single larger turbine of the type included for the other systems would be prohibitively expensive to install and maintain because of the mobilization and special equipment required. This cost would typically be spread over a wind installation with many turbines. In the case of Moloka'i and Lana'i this cost would have to be spread over a single turbine.
- The ability to properly evaluate WTE facilities in the 2016 PSIP update is contingent upon the ability to acquire reliable data regarding Hawai'i -specific cost and performance characteristics of a WTE plant at or close to the sizes shown above. The Companies welcome input from the Parties in the development of the assumptions for WTE.

UTILITY-SCALE ENERGY STORAGE RESOURCES AND THEIR COSTS

Energy Storage Applications

The 2014 PSIPs included "Appendix J: Energy Storage for Grid Applications" which discussed energy storage technologies in detail, including the various technologies and applications. The information presented in the 2014 PSIP Appendix J remains relevant, so we refer the reader there for a detailed background discussion of the basics of energy storage and emerging technology types.

For the 2016 Updated PSIPs, we developed detailed assumptions around several applications, using several technologies. The applications, uses, duty cycles, technologies and sizes of energy storage systems are summarized in Table 4-9.

Application	Description of Use	Duration	Storage Duty Cycles	Depth of Discharge	PSIP Technologies	Sizes Available to Planners
Inertia	Provide ride-through of momentary system disruptions; avoid system contingency	Seconds	5,000 per year	Deep (up to100%)	Flywheels	Flywheel 10 MW
Contingency	Near instantaneous (< 7 cycles) to serve load when a system contingency (generation trip or sudden transmission fault) occurs; frequency response	Up to 30 minutes	≈ 10 per year	Deep (up to100%)	Lithium Ion BESS	BESS: 1, 5, 10, 20, 50, 100 MW
Regulation	Smooth fluctuations in system load; smooth fluctuations in output of variable renewables; frequency response	Up to 30 minutes	≈ 15,000 per year	Shallow (20% to 50%)	Lithium Ion Battery Energy Storage Systems (BESS). Pumped Storage Hydroelectric (PSH)	BESS: 1, 5, 10, 20, 50, 100 MW PSH: 30, 50 MW
Load Shifting	Store excess variable renewable generation for use at a later time; circuit level support to accommodate DER; non-transmission alternative	1 – 8 Hours	Daily	Deep (up to100%)	Lithium Ion BESS PSH Hydrogen Energy Storage CSP with Storage	BESS: 1, 5, 10, 20, 50, 100 MW BESS: 2 MW for grid support PSH: 30, 50 MW Hydrogen: not commercial CSP: 100 MW

Table 4-9. 2016 Updated PSIP Energy Storage Applications, Sizes, Technologies

Cost Assumptions Related to Energy Storage

The specific capital cost assumptions for energy storage resources are presented in Appendix A. A detailed discussion of the storage alternatives and how they have been considered in Appendix D. Figure 4-6 depicts the underlying constant 2016 $

considered in Appendix D. Figure 4-6 depicts the underlying constant 2016 $ assumptions for the capital costs associated with selected sizes, technologies and applications for energy storage systems assumed in the interim PSIP updates.

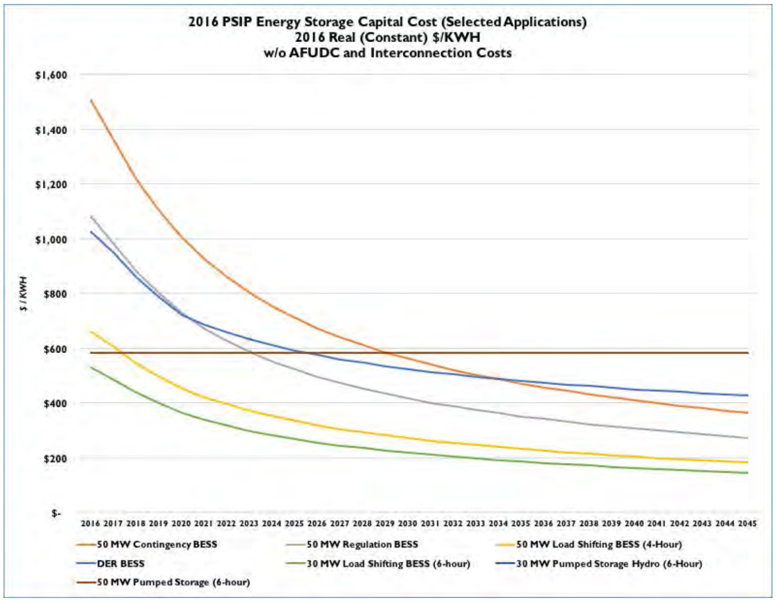

Figure 4-6. 2016 PSIP Energy Storage Capital Costs –Selected Applications

DISTRIBUTED ENERGY RESOURCES COST ASSUMPTIONS

DER resource capital cost assumptions were developed utilizing the same methodology described above for utility-scale resources, and utilizing many of the same sources. For the purposes of the PSIP DER analysis, we concentrated on rooftop solar PV, residential lithium-ion BESS and behind-the-meter commercial customer class BESS. In particular, for each of these technologies, we utilized IHS Energy's projections of distributed solar and energy storage costs, applied Hawai'i locational adjustments using RSMeans data, and added 4% for the Hawai'i general excise taxes. For solar PV in particular, we validated this data against anecdotal data points obtained through a conversation with a solar PV integrator active in the Hawai'i market.[18]

The available data for residential systems from IHS included only the storage medium, and not the balance of plant components, under the assumption that the distributed storage would be installed in conjunction with a solar PV system that incorporates the inverter and other balance of plant items. We believe that there are opportunities for

[18] Companies' consultant HDBaker & Company's private conversation with a company that provides turnkey solar PV solutions in Hawai'i.

stand-alone distributed energy storage. Accordingly, we added balance of plant cost estimates to develop stand-alone storage costs.

The projections of capital costs for distributed solar PV and customer-owned BESS energy storage systems are included in the tables in Appendix A.

INTER-ISLAND CABLE ASSUMPTIONS

Analysis of an inter-island cable system was not modeled for this interim status report. Our 2016 PSIP analysis, however, would consider the feasibility of inter-island cables. Because of the distances involved between the islands, interconnections between the islands would be accomplished by using High Voltage Direct Current (HVDC) technology, including converter stations on either end of a submarine cable. Submarine HVDC systems have been successfully deployed around the world, and the market for HVDC systems is expected to dramatically increase in the future.[19]

There are relatively few vendors of HVDC technology, however the vendors that are active in this market are global players, with large balance sheets and the ability to support this technology. HVDC systems exhibit a high level of reliability and are highly controllable, providing flexibility in terms of providing grid services.

Capital cost assumptions for a 200 MW and 400 MW cable system between Maui and O‘ahu were developed by NextEra Energy Resources in consultation with HVDC vendors. HVDC projects are typically developed with the vendor providing turnkey engineering-procurement-construction (EPC) serves with guaranteed prices (subject to sliding cost categories related to commodity prices), guaranteed schedules, and guaranteed performance.

[19] http://www.marketsandmarkets.com/Market-Reports/hvdc-grid-market-1225.html.

SYSTEM OPERATING AND RELIABILITY CRITERIA

General Electric (GE), working under a contract with the Hawai'i Natural Energy Institute (HNEI)[20], developed a formula for determining the amount of regulating reserve necessary to maintain the minute-to-minute balance between supply and demand on the O'ahu grid. The formula is:

Required regulating reserve amount equals the sum of:

Approximately 1 MW regulating reserve for each 1 MW of delivered wind and PV generation up to 18% of nameplate capacity of wind and PV during daytime the hours of 7 AM to 6 PM; plus

1 MW regulating reserve for each 1 MW of delivered wind and PV generation up to 23% of nameplate capacity during the hours of 6 PM to 7 AM

GE developed the formula by converting the hourly MW reserve requirements from previous studies into an hourly reserve requirement as a percent of the total online renewable capacity. The reserves represent the regulating reserve portion of the total reserve requirement only after taking into account quick-start reserve capability on O'ahu provided by existing gas-turbine and reciprocating engines (CT-1, Airport DSG, Waiau 9, and Waiau 10).

Electric Power Systems (EPS) developed a formula for Lana'i, Moloka'i, and Hawai'i Island. The formulas are based on resources whose outputs respond directly to energy source availability, without mitigation for smoothing or ramp control. That formula is:

Required regulating reserve amount equals the sum of:

1 MW regulating reserve for each 1 MW of delivered wind generation up to 50% of nameplate capacity of wind, plus

1 MW regulating reserve for each 1 MW delivered DG-PV generation up to 20% of nameplate capacity of DG-PV, plus

1 MW regulating reserve for each 1 MW of delivered utility-scale PV generation up to 60% of nameplate capacity of utility-scale PV

[20] Refer to HNEI study material http://www.hnei.hawaii.edu/projects/hawaii-rps-study and http://www.hnei.hawaii.edu/projects/hawaii-solar-integration for more information.

The amount of regulating reserve required on Maui to regulate frequency because of the variability of output from variable generation resources is currently determined from a formula derived in the December 19, 2012 Hawai‘i Solar Integration Study prepared by GE for the National Renewable Energy Laboratory, HNEI, Hawaiian Electric Company and Maui Electric Company. That formula is:

The greater of 6 MW, or

1 MW regulating reserve for each 1 MW of delivered wind and solar power up to a maximum of 27 MW, less 10 MW for the KWP II BESS. (Solar power includes behind-the-meter and grid-side PV.)

Maui Electric plans to transition to the EPS regulating reserve formula. But first, Maui Electric must determine the effects on costs and curtailment with the addition of 40 MW of internal combustion engines, a 20 MW regulating reserve BESS, a 20 MW contingency reserve BESS, and the decommissioning of Kahului Power Plant.

5. Interim Results

CANDIDATE PLANS, CASE RUNS, AND PRELIMINARY RESULTS

Presented here are previews of our initial sets of candidate plans that are taking shape, how these were developed from the assumptions and models, and a discussion of the characteristics of each. It should be stressed that these are results based on the status of analysis at this time and could change substantially with further analysis.

We will be developing additional candidate plans for inclusion in our Updated PSIPs.

Consolidated Preliminary Results

Consolidated RPS Attainment

Figure 5-7 identifies the Hawaiian Electric Companies' Consolidated RPS % achieved for each target year and the amount of renewable energy generated by the systems to serve the demand. Consistent with current Hawaii statutory language defining RPS, the RPS formula includes customer generation and utility-scale generation in the numerator but only utility-scale generation in the denominator. Hence, the RPS value can exceed 100%.

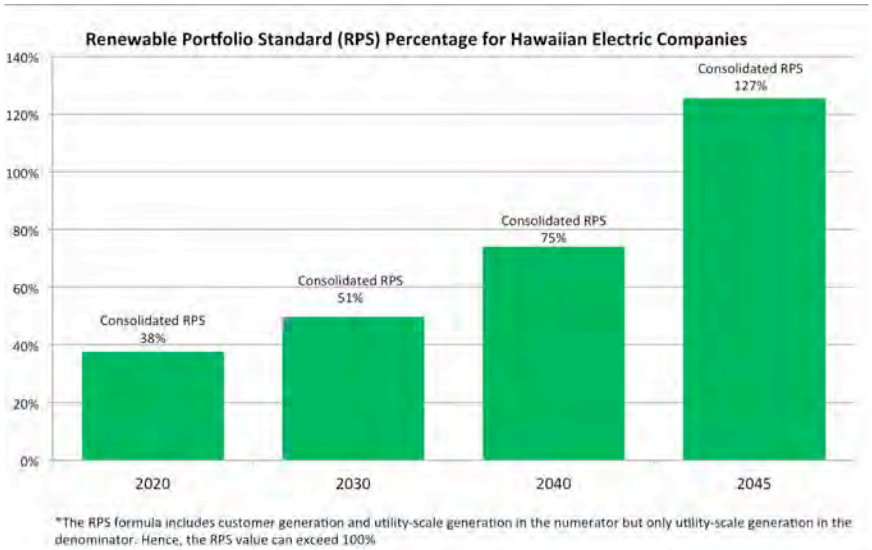

Figure 5-7. Consolidated RPS Percentage

The preliminary case runs achieve 100% renewable by 2045 with an initial combination of DER, DR, utility-scale wind, utility-scale PV, waste-to-energy/biomass, geothermal, existing run-of-the-river hydro, and biofuels. The mix of resources will continue to be refined and optimized through future iterations of the various cases. Additional options of DR and DER, refined ancillary service requirements, and additional and/or alternative combinations of utility-scale renewables will be evaluated.

To be clear, by 2045, the Companies intend to produce 100% of its energy from renewable resources.

Generation Mix

The existing systems will transition to a 100% renewable generating system over time. Figure 5-8 provides a snapshot of how the generation mix of resources could change over time to 100% renewable generation by 2045 with LNG as a transitional fuel.

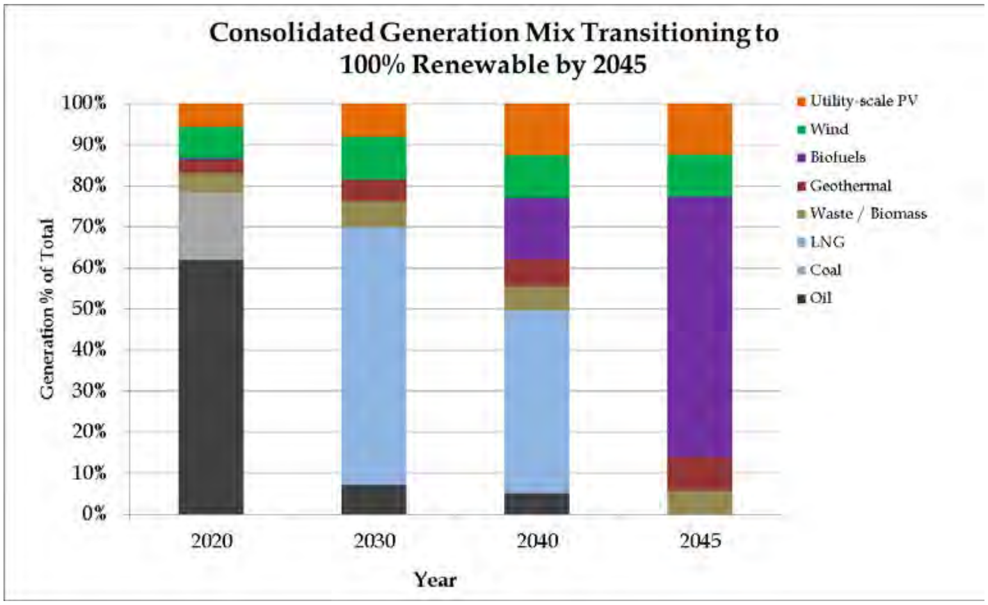

Figure 5-8. Consolidated Generation Mix Transitioning to 100% Renewables by 2045

The mix of resources will continue to be refined and optimized through future iterations of the various cases. The Companies plan to evaluate replacing the biofuels used in the 2045 timeframe with additional renewable resources such as wind and PV resources. Additional options of DR and DER, refined ancillary service requirements, and additional and/or alternative combinations of utility-scale renewables and storage systems will be evaluated.

Environmental Impacts

Moving towards a 100% renewable future provides environmental benefits for future generations. Figure 5-9 depicts the estimated emission levels for CO_2 on a consolidated basis for plans with LNG and without LNG. For O‘ahu, Case 1 (100% Renewable Reference Case) is used as the Baseline (No LNG), and Case 4 (100% Renewable with Modernization and Transitional LNG Fuel) is used as the With LNG plan. Figure 5-9 does not include estimates for CO_2 emissions for biomass and geothermal on Hawai‘i Island and Maui due to insufficient time to obtain necessary data but will be included in future results.

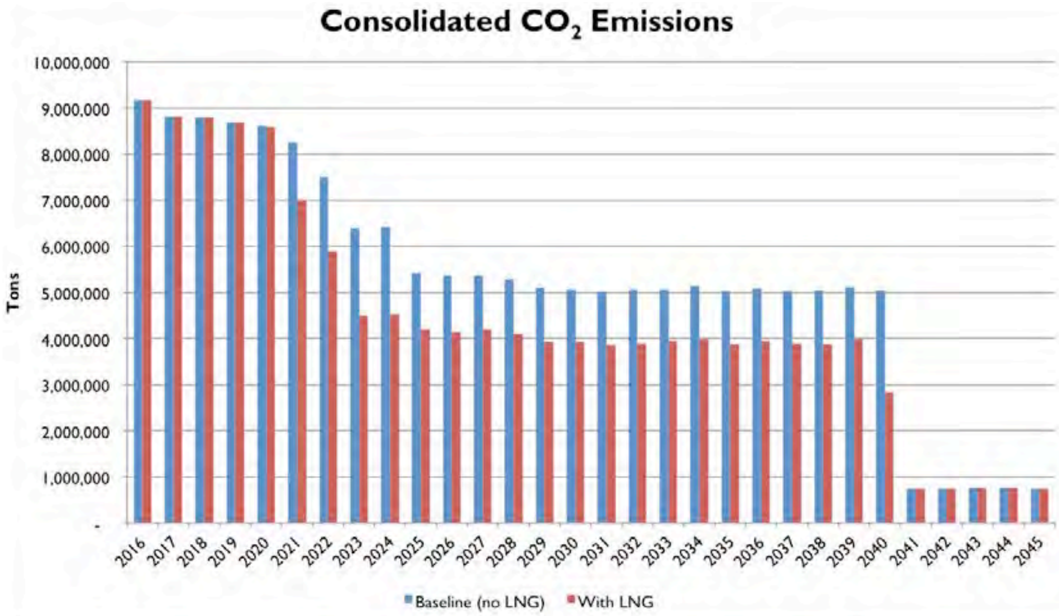

Figure 5-9. Consolidated CO_2 Emissions

LNG Volumes

Initial cases 3 and 4 for O‘ahu, the initial case for Hawai‘i Island, and the initial Maui Electric case included LNG as the transitional fuel from oil to 100% renewables. For the initial analyses, the volumes of LNG were not constrained.

As depicted in Figure 5-7: Consolidated RPS Percentage and Figure 5-8: Consolidated Generation Mix Transitioning to 100% Renewables by 2045, LNG does not hinder progress towards integrating renewable energy.

O‘ahu Case Runs

The initial set of O‘ahu case runs were developed with the following considerations:

1. Transitioning to 100% renewable energy by 2045 with an integrated portfolio of DER, utility-scale renewable resources, and the addition of DR and energy storage to provide ancillary services.
2. Adding firm, flexible, dispatchable capacity to replace existing fossil-fueled capacity provide additional ancillary services by needed to enable greater amounts of variable renewable generation.
3. With a focus on near-term resource requirements, relative plan costs with and without generation modernization need to be examined because of the potential for better efficiency and flexibility that will enable the integration of more variable

renewable energy over time and at the same time, to examine the near-term needs for capacity for O'ahu.

4. Relative plan costs with and without LNG need to be examined to understand the impact of LNG on customer costs and emission levels.
5. Examine all cases under high and low fuel price forecasts to understand the impact of this critical input on the relative performance of cases.

All case runs for O'ahu meet 100% renewable energy by 2045 and incorporate initial DG-PV projections and DR portfolios.

Logic in Developing All O'ahu Cases

For the development of all cases, the first step was to establish the forecasted electricity load and energy demands over the 30-year period. An initial level of DER, including DR resources, was included in each case. We will develop cases with various levels of DER, but we were only able to develop and evaluate cases with a baseline level of DER at this point of the update. For the initial analysis, DG-PV has been projected to achieve 988 MW by 2045 across all cases. The forecast will need to be fine-tuned and optimized with explicit consideration of integration costs and curtailment based on circuit and system level screens

With the RPS requirements as a baseline constraint, an initial set of utility-scale renewables comprised of utility-scale solar and utility-scale wind were added. Wind and solar were selected for O'ahu's baseline renewable portfolio because of the lack of large levels of new firm renewable resources (unlike Maui and Hawai'i Island). Timing of the addition of utility-scale and solar PV was spread over the planning period in this baseline to add such utility-scale systems in blocks that takes advantage of economies of scale systems; and meet intermediate RPS milestone requirements. Costs and availability of such resources developed for the interim PSIP update and based upon independent third party sources were used. Several supporting efforts have been undertaken, and are still underway, to better understand the reasonable wind and solar PV resource capability of each island. While not complete, the findings indicate that O'ahu will face constraints that will limit the contribution it can make to the 100% RPS target. For the first iteration of plans, RPS compliance was fulfilled through the addition of biofuels to O'ahu to meet RPS requirements.

Initial candidate resource plans with LNG in the form being pursued today, or an advanced combined-cycle unit built at an active generating station on O'ahu could only reasonable take place in this specific form if the proposed merger of NextEra and Hawaiian Electric Companies takes place.

This assumption serves as the benchmark for future consideration of alternative options such as:

- Additional or alternative on-Oʻahu renewable resources, both distributed and utility-scale
- The addition of an inter-island cable, which would function as a grid-tie with Oʻahu and unlock the development of additional renewable resources on islands such as Maui and Hawaiʻi Island where the that renewable resource potential might exceed what could reasonably be consumed locally
- The development of offshore wind resources

Case 1. 100% Renewable Reference Case. The 100% Renewable Reference Case was developed with the assumption of no LNG availability and the continued use of oil for dispatchable fossil generation. To serve in a role as a reference case, this case minimizes changes to firm generation but includes renewable energy resources similar to other cases.

This scenario includes the addition of:

- Achieving 988 MW of distributed PV by 2045 (initial market forecast).
- Initial projection of Demand Response potential.
- 137 MW of utility-scale PV by 2016.
- 50 MW Schofield Generating Station in 2018.
- 24 MW utility-scale wind in 2018.
- 90 MW contingency BESS in 2021.
- 475 MW of additional utility-scale PV installed in multiple years.
- 150 MW of additional utility-scale wind installed in multiple years.
- 127 MW of new, firm, flexible generation sited at military bases.
- Biofuels used in dispatchable generation in order to fulfill remaining RPS requirements.
- Retirement of 382 MW of existing firm capacity generation.

Case 2. 100% Renewable with Modernization. Case 2 is a variant of the Reference Case and developed to evaluate the benefits and costs of replacing three baseload steam units with flexible 383 MW advanced combined cycle generation at the Kahe site. Like the reference case, this case includes the same levels of DER and DR resources, the same utility-scale renewable resources, assumes no availability of LNG and the continued use of oil for fossil fired generation.

Case 2, therefore, includes the following resources:

- Achieving 988 MW of distributed PV by 2045 (initial market forecast).
- Initial projection of Demand Response potential.
- 137 MW of utility-scale PV by 2016.
- 50 MW Schofield Generating Station in 2018.
- 24 MW utility-scale wind in 2018.
- 90 MW contingency BESS in 2021.
- 475 MW of additional utility-scale PV installed in multiple years.
- 150 MW of additional utility-scale wind installed in multiple years.
- 127 MW of new, firm, flexible generation sited at military bases.
- 383 MW of new, firm, advanced combined cycle generation.
- Biofuels used in dispatchable generation in order to fulfill remaining RPS requirements.
- Retirement of 718 MW of existing firm capacity generation.

Same as Case 1, except that Kahe 1–3 are deactivated and replaced with modern, flexible 383 MW 3x1 combined cycle generation.

Case 3. 100% Renewable with Transitional LNG Fuel. Case 3 contains the same DER, DR, and utility-scale renewable energy generation, and firm, dispatchable generation as the reference case. However, Case 3 assumes the availability of LNG supply. LNG in Kalaeloa and in a portion of the Hawaiian Electric steam fired generators.

Resources in Case 3 include:

- Achieving 988 MW of distributed PV by 2045 (initial market forecast).
- Initial projection of Demand Response potential.
- 137 MW of utility-scale PV by 2016.
- 50 MW Schofield Generating Station in 2018.
- 24 MW utility-scale wind in 2018.
- 90 MW contingency BESS in 2021.
- 475 MW of additional utility-scale PV installed in multiple years.
- 150 MW of additional utility-scale wind installed in multiple years.
- 127 MW of new, firm, flexible generation sited at military bases.
- LNG availability from 2021 through 2040.
- Biofuels used in dispatchable generation in order to fulfill remaining RPS requirements.

- Retirement of 382 MW of existing firm capacity generation.

Case 4. 100% Renewable with Modernization and Transitional LNG Fuel. Case 4 was developed to take advantage of the clean burning properties of LNG (when compared to other fossil fuels) and the efficiency and operational flexibility of a modern, advanced combined cycle plant. In addition to the inclusion of the same DER, DR, and renewables as the reference case, Case 4 includes the addition of LNG and a 383 MW advanced combined cycle at the Kahe site. The additional capacity provided by the advanced combined cycle unit allows for the retirement of greater levels of existing steam generation.

As a result, Case 4 is comprised of:

- Achieving 988 MW of distributed PV by 2045 (initial market forecast).
- Initial projection of Demand Response potential.
- 137 MW of utility-scale PV by 2016.
- 50 MW Schofield Generating Station in 2018.
- 24 MW utility-scale wind in 2018.
- 90 MW contingency BESS in 2021.
- 475 MW of additional utility-scale PV installed in multiple years.
- 150 MW of additional utility-scale wind installed in multiple years.
- 127 MW of new, firm, flexible generation sited at military bases.
- 383 MW of new, firm, advanced combined cycle generation at the Kahe site.
- LNG availability from 2021 through 2040.
- Biofuels used in dispatchable generation in order to fulfill remaining RPS requirements.
- Retirement of 718 MW of existing firm capacity generation.

Case 5. 100% Renewable with Limited Modernization. Key near-term resources in Case 4 – LNG in the form being pursued today and the advanced combined-cycle generation built at an active generating station could only reasonably take place in this specific form if the proposed merger of NextEra and Hawaiian Electric take place. Case 5 was developed to establish a candidate plan with additional flexible generation beyond Cases 1 and 3 which could be reasonably developed without the proposed NextEra and Hawaiian Electric Companies merger.

Case 5 increases the size of the military sited generating station at MCBH to provide additional flexible generation for the island and greater generation located on the eastern side of the island to serve windward and East O‘ahu customers during islanded situations. The timing of both JBPHH and MCBH military sited generation was timed with the need for new firm capacity on the system. Although Case 5 assumes that LNG is not available as a fuel source to substitute for oil, the Hawaiian Electric Companies will continue to evaluate and agnostically pursue use of LNG as a cleaner, less volatile fossil fuel for use in dispatchable, firm generation as an alternative to oil in our continued effort to lower costs to customers.

For the purposes of Case 5, therefore, is comprised of the following resources:

- Achieving 988 MW of distributed PV by 2045 (initial market forecast).
- Initial projection of Demand Response potential.
- 137 MW of utility-scale PV by 2016.
- 50 MW Schofield Generating Station in 2018.
- 24 MW utility-scale wind in 2018.
- 90 MW contingency BESS in 2021.
- 475 MW of additional utility-scale PV installed in multiple years.
- 150 MW of additional utility-scale wind installed in multiple years.
- 154 MW of new, firm, flexible generation sited at military bases.
- LNG availability from 2021 through 2040.
- Biofuels used in dispatchable generation in order to fulfill remaining RPS requirements.
- Retirement of 407 MW of existing firm capacity generation.

All O'ahu case runs were performed using the 2015 EIA Reference, 2015 FAPRI Reference, and 2015 EIA Average Henry Hub Spot Prices for Natural Gas fuel price forecasts, and the February 2016 Forward/Hybrid Curve, 2015 FAPRI Low, and Chicago Mercantile Exchange Henry Hub Natural Gas Futures (Escalated) fuel price forecasts.

Maui Case Runs

All case runs for Maui meet 100% renewable energy by 2045. Scenarios using the 2015 EIA Reference, 2015 FAPRI Reference, and 2015 EIA Average Henry Hub Spot Prices for Natural Gas fuel price forecasts, and the February 2016 Forward/Hybrid Curve, 2015 FAPRI Low, and Chicago Mercantile Exchange Henry Hub Natural Gas Futures (Escalated) fuel price forecasts were examined.

All cases assume that the South Maui Renewable Resources 2.87 MW PV facility and the Ku'ia Solar 2.87 MW PV facility are on the system in 2017. Maui Electric filed applications for approval of PPAs with these developers and is awaiting approval.

For the initial analysis, DG-PV has been projected to achieve 162 MW by 2045 across all cases. The forecast will need to be fine-tuned and optimized with explicit consideration of integration costs and curtailment based on circuit and system level screens. In addition, demand response programs were not yet included in the resource plans as data were not yet available. An optimal level of demand response programs will be included in the resource plans. Further, cases may be re-run to refine resource mix and timing to more optimal levels.

All cases assume that the Kahului Power Plant will be retired at the end of 2022. The compliance plan for the National Pollution Discharge Elimination System permit is to decommission the power plant no later than November 2024. Replacement firm, dispatchable capacity must be added before the power plant is decommissioned in order to maintain Maui Electric's system reliability. For the purposes of the analyses, it was assumed that internal combustion engines (diesel engines) of sufficient total capacity would be installed. It was further assumed in all cases that certain existing diesel engines would be deactivated when not needed to maintain generating system reliability. From time to time, they would need to be reactivated when there is not a sufficient amount of capacity to satisfy Maui Electric's capacity planning criteria.

6. 100% Renewable Case 1: Certain diesel engines will be added in addition to geothermal units being added late in the planning period to satisfy capacity needs and to continue moving toward 100% renewable energy. Biofuels would be used in the diesel engines to achieve 100% renewable energy. The 2015 EIA Reference and 2015 FAPRI Reference forecasts and baseline DER were used. This case includes the use of LNG at the 2015 EIA Average Henry Hub Spot Prices for Natural Gas.

7. 100% Renewable Case 2: Same as Item 1 above, except without LNG. To be used in the existing Dual Train Combined Cycle No. 1 and No. 2 beginning in 2021. The 2015 EIA Reference and 2015 FAPRI Reference forecasts and baseline DER were used.

8. 100% Renewable Case 3: Same as Item 1 above, except with the February 2016 Forward/Hybrid Curve with the FAPRI Low, and Chicago Mercantile Exchange Henry Hub Natural Gas Futures (Escalated) fuel price forecasts fuel price forecasts.

9. 100% Renewable Case 4: Same as Item 1 above, except without LNG and the February 2016 Forward/Hybrid Curve with the FAPRI Low fuel price forecasts.

As part of future additional analyses, a case without geothermal units will be examined. Instead, other renewable resource additions such as biomass or waste-to-energy facilities, will be examined.

The cost of biomass energy is dependent on the source and availability of biomass fuel stock.

The primary function of waste-to-energy facilities is to meet a societal need (that is, dispose of municipal waste and minimize the need for landfill space). Electrical energy production is a byproduct of their operation. The sizing and timing of installation are not within the control of the electric utility. The pricing of energy from such facilities is dependent, in large part, on how the operating entity intends to allocate their revenue streams between the tipping fee charged to waste collectors who deliver the waste to the plant and rate charged to the electric utility for electrical capacity and for energy sales. A higher tipping fee can reduce the rate charged for electricity. A lower tipping fee will require that the rate for electricity be higher. The actual rate to be charged by the operating entity to the electric utility will be a product of negotiation. Because of the nature of the technology used, the output from a waste-to-energy facility is scheduled, rather than economically dispatched.

Given the unique nature of waste-to-energy facilities, the integration of such a scheduled resource into the long-term plan will be treated as a sensitivity to evaluate impacts on resource costs when it is added into the plan.

Considerations for Developing the Maui Island Case Runs

The initial Maui case runs were developed with the following considerations:

- Adding firm, dispatchable renewable capacity to replace conventional fossil-fueled capacity is desirable because firm, dispatchable renewable capacity can provide ancillary services that are similar to that of conventional generation, if properly designed, and it can provide a much greater contribution to RPS compared to variable generation.
- Geothermal is a potential firm, dispatchable renewable capacity resource on Maui. The geothermal resource is positioned later in the planning period in consideration of the development time.
- Other potential firm, dispatchable renewable capacity resources (such as biomass) can be examined in additional case runs.
- Relative plan costs with and without LNG need to be examined because of LNG's potential role in Maui's energy future.
- Relative plan costs with and without LNG need to be examined under high and low fuel price forecasts because of the uncertainty of future fuel prices.

Lana'i and Moloka'i Case Runs

All case runs for Moloka'i and Lana'i meet 100% renewable energy by 2045. Scenarios using the 2015 EIA Reference, 2015 FAPRI Reference, and the February 2016 Forward/Hybrid Curve, 2015 FAPRI Low, fuel price forecasts were examined.

For the initial analysis, DR programs were not included in the resource plans as data were not yet available. An optimal level of demand response programs will be included in the resource plans. Further, cases may be re-run to refine resource mix and timing to more optimal levels.

1. Meet RPS milestones and achieve 100% renewable energy by 2045 with biofuels.
2. Meet RPS milestones and achieve 100% renewable energy by 2045 without thermal generation (that is, with distributed or utility-scale PV) to provide electrical energy and with various other resources, such as demand response, energy storage (including flywheels), synthetic inertia and curtailed energy, to satisfy system security requirements and fault current.
3. Meet more aggressive RPS milestones of 35% of sales by the end of 2020 and 50% of sales[21] by the end of 2030 using biofuels.
4. Same as Item 3, except use PV and energy storage resources instead of biofuels.
5. Meet accelerated RPS milestones of 50% of sales by the end of 2020 and 100% of sales by the end of 2030 using biofuels.
6. Same as Item 5, except use PV and energy storage resources instead of biofuels.

Considerations for Developing the Lana‘i and Moloka‘i Case Runs

The Lana‘i and Moloka‘i case runs were developed with the following considerations:

- The Commission noted that "…the smaller size of the Moloka‘i and Lana‘i island systems could provide an opportunity for the Companies to work with these island communities to determine an affordable plan to reach 100% renewable systems."[22]
- As small systems, Lana‘i and Moloka‘i provide an opportunity to evaluate the potential to operate each grid without thermal generation.
- LNG will not be used on these islands.
- Biofuels can be used in existing thermal generation to achieve 100% RPS without major capital investments.
- PV, wind, and energy storage (where energy storage can be used for ancillary services and load shifting) can be used in combination to potentially operate each island grid without thermal generation.
- On these smaller island grids, there may be an opportunity to achieve a 100% renewable future sooner.

[21] The Hawaiian Electric Companies and NextEra Energy made these commitments in the Change of Control proceeding (Docket No. 2015-0022).

[22] Order No. 33320 at 77.

Hawai'i Island Case Runs

All case runs for Hawai'i Island meet 100% renewable energy by 2045. Scenarios using the 2015 EIA Reference, 2015 FAPRI Reference, and 2015 EIA Average Henry Hub Spot Prices for Natural Gas fuel price forecasts, and the February 2016 Forward/Hybrid Curve, 2015 FAPRI Low, and Chicago Mercantile Exchange Henry Hub Natural Gas Futures (Escalated) fuel price forecasts were examined.

For the initial analysis, DG-PV has been projected to achieve 182 MW by 2045 across all cases. The forecast will need to be fine-tuned and optimized with explicit consideration of integration costs and curtailment based on circuit and system level screens.

For the initial set of case runs, demand response programs were not yet included in the resource plans as data were not yet available. In the ongoing set of case runs, an optimal level of demand response programs will be included in the resource plans.

Hu Honua is the next planned renewable energy resource addition on the Hawai'i Electric Light system. However, Hu Honua has missed major project milestones under the terms of its power purchase agreement. As a contingency plan and in order to inform on resource options, the interim PSIP update analysis does not assume Hu Honua as being available.

The initial sensitivities are based around LNG and fuel price forecasts and DER, and 100% renewable energy is achieved through fuel conversions. In the later runs, additional case assessments will build on the findings of the initial runs to produce cases to achieve 100% renewable energy through new resource options that can be acted on in phases. Through the case evaluation, these cases will inform a technology agnostic resource acquisition to certain specified performance and operational requirements. The plan would look at resource additions in phases and achieve 100 renewable energy by 2045 with the addition of new resources or with fuel-switching.

The initial sensitivities are as follows:

1. A future geothermal resource and a future biomass resource are included in the sensitivity case. Hu Honua, as characterized by its specific PPA, is not included in the resource plan as a means to evaluate contingency options should this planned dispatchable resource not come online as expected. The 2015 EIA Reference and 2015 FAPRI Reference forecasts and baseline DER were used. Keahole and HEP combined cycle plants are converted to LNG. The 2015 EIA Average Henry Hub Spot Prices for Natural Gas were used.

2. Same as Item 1 above, except the Keahole and HEP combined cycle plants are not converted to LNG.

3. Same as Item 1 above, except with the February 2016 Forward/Hybrid Curve with the FAPRI Low, and Chicago Mercantile Exchange Henry Hub Natural Gas Futures (Escalated) fuel price forecasts.

4. Same as Item 1 above, except without LNG and with the February 2016 Forward/Hybrid Curve with the FAPRI Low fuel price forecasts.

As explained above in the Maui case runs, the integration of a scheduled waste-to-energy resource into the long-term plan will be treated as a sensitivity to evaluate the impacts on resource costs when it is added into the plan.

In later analyses, additional cases will be run and analyzed to determine the appropriate selection of the first resource addition, the second resource addition, and the resources needed to achieve 100% renewable energy.

First Resource Addition – Near Term. This case study will compare low-cost variable energy additions without storage and firm dispatchable resources evaluated to be feasible in the time frame. The variable resources will be utility-scale wind and solar, and will incorporate technical and operational characteristics to minimize system operational and integration costs, but will not require equivalency to a thermal generation resource in terms of such items as active power control, voltage regulation, frequency response, or smoothing. The dispatchable renewable energy shall be assumed to have characteristics allowing displacement of a reliability must-run thermal generator and flexibility in location. The cost will be based upon biomass because of the time-frame and challenges in geothermal development.

The following case comparisons will be modeled to evaluate cost and RPS impacts:

- Dispatchable renewable energy, based upon dispatchable biomass resource costs.
- Utility-scale wind, based on similar potential capacity factor as existing plants.
- Utility-scale solar assuming a capacity factor based on particular location.

Second addition, longer term. Building upon the findings of the near-term case, consider cost and renewable energy impacts of a second renewable energy resources to achieve the next target of RPS. For the variable firming, storage would be required to provide firm capacity and inertial response or other technologies to create a virtual firm dispatchable plant is assumed to be displacing must-run thermal.

This case study uses cases to compare possible resources:

- Firm dispatchable renewable energy, which, considering the longer time frame, can include West Hawai‘i Geothermal. Cost evaluation will be based on the best dispatchable renewable energy price.
- Firm solar.

- Firm wind.

100% Renewable Energy Plan. The run would use the best options of the first and second resource additions and evaluate the addition of other resources, such as wind and solar in combination with energy storage, to determine if it is more cost-effective than conversion to biofuels.

Considerations for Developing the Hawai'i Island Case Runs

The Hawai'i case runs were developed with the following considerations:

- Adding firm, dispatchable renewable capacity to replace conventional fossil-fueled capacity is desirable because firm, dispatchable renewable capacity can provide ancillary services that are similar to that of conventional generation, if properly designed, and it can provide a much greater contribution to RPS compared to variable generation.
- Geothermal and biomass resources are potential firm, dispatchable renewable capacity resource on Hawai'i Island.
- Relative plan costs with and without LNG need to be examined because of LNG's potential role in Hawai'i's energy future.
- Relative plan costs with and without LNG need to be examined under high and low fuel price forecasts because of the uncertainty of future fuel prices.

We want to emphasize that the Hawai'i Island analysis is currently very preliminary.

DIFFERENTIAL FINANCIAL RESULTS

Presented here are the incremental financial impact on total revenue requirement between the baseline case and each additional case, under the low and high fuel price forecasts. A summary of the incremental capital expenditures for each case as compared to the baseline case is also presented. Status information options being explored for the treatment of net plant values of retired plant is also presented.

All financial results are all reported in nominal dollars.

Hawaiian Electric Company's Financial Implications

Differential Revenue Requirements

The differential revenue requirement between the baseline case and each additional case for the two ranges of fuel forecasts are presented in Figure 5-10 and Figure 5-11.

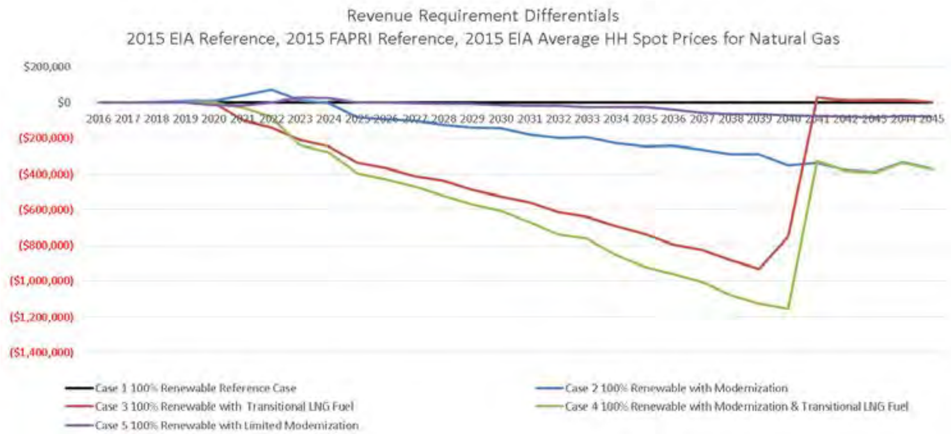

Figure 5-10. Hawaiian Electric Revenue Requirement Differentials: 2015 EIA Reference, 2015 FAPRI Reference, 2015 EIA Average HH Spot Prices for Natural Gas

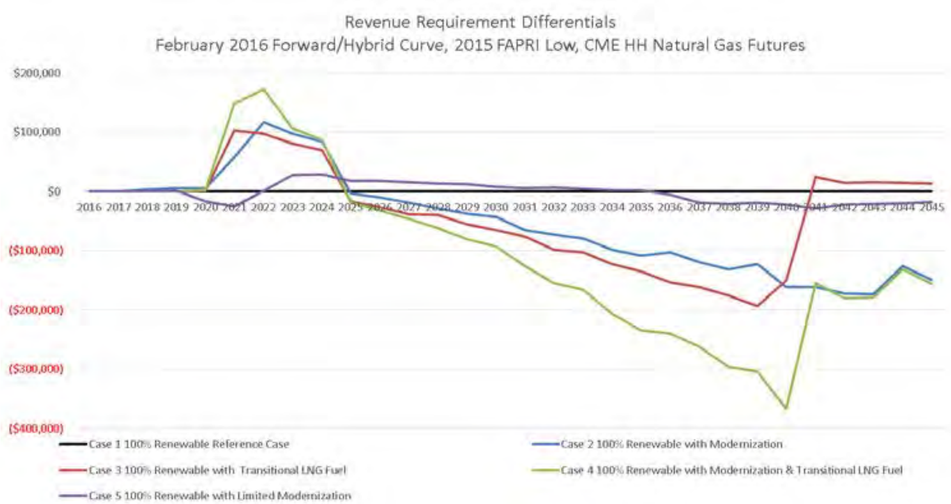

Figure 5-11. Hawaiian Electric Revenue Requirement Differentials: February 2016 Forward/Hybrid Curve, 2015 FAPRI Low, CME HH Natural Gas Futures

The Net Present Value of the differential revenue requirements over the 30 year forecast period are presented in Table 5-10. Note that negative amounts are an improvement over the reference case and provides a benefit to our customers.

Millions $	**Fuel Forecast**	
Case	*February 2016 Forward/Hybrid Curve, 2015 FAPRI Low, CME HH Natural Gas Futures*	*2015 EIA Reference, 2015 FAPRI Reference, 2015 EIA Average HH Spot Prices for Natural Gas*
Case 1 100% Renewable Reference Case (Black)	–	–
Case 2 100% Renewable with Modernization (Blue)	–$142	–$879
Case 3 100% Renewable with Transitional LNG Fuel (Red)	–$150	–$2,842
Case 4 100% Renewable with Modernization & Transitional LNG Fuel (Green)	–$377	–$3,530
Case 5 100% Renewable with Limited Modernization (Purple)	$14	–$126

Table 5-10. NPV (2016$) of Differential Revenue Requirements for the O‘ahu Cases

These interim results indicate that investment in generation modernization and commitment to LNG result in savings for customers, with the magnitude of these savings dependent on whether the high or low fuel cost environment is realized.

Capital Expenditures

The differential impacts on revenue requirements for each case presented above take into account the capital investment differential between each case. Table 5-11 presents the differential capital investment in each 5 year period between Case 1 (the baseline comparison case) and each additional case. Of course, there is no change in capital expenditures between the high and low fuel forecasts.

Millions Nominal $	Capital Expenditure Differential Compared to Case 1						
Case	*2016–2020*	*2021–2025*	*2026–2030*	*2031–2035*	*2036–2040*	*2041–2045*	*Cumulative*
Case 1 100% Renewable Reference Case	–	–	–	–	–	–	–
Case 2 100% Renewable with Modernization	$738	$25	$24	-$105	$41	$67	$791
Case 3 100% Renewable with Transitional LNG Fuel	$232	$58	–	–	–	–	$290
Case 4 100% Renewable with Modernization & Transitional LNG Fuel	$939	$55	–$11	–$132	$28	$67	$947
Case 5 100% Renewable with Limited Modernization	–$190	$417	–	$8	–$137	$1	$99

Table 5-11. Hawaiian Electric Capital Expenditure Differential Compared to Case 1

Removal Costs

The incremental revenue requirement impact analysis presented above does not include any costs for removal costs associated with retired generating units. There will be removal costs and these costs are almost certainly to be in excess of the existing removal regulatory liability balance, but the magnitude and timing of these costs has not yet been determined for each of the cases analyzed. These costs will be incorporated into our ongoing PSIP analysis.

Treatment of Remaining Book Value of Generation Assets at Retirement

The Updated PSIPs for Hawaiian Electric will incorporate the retirement of one or more generating units. In some cases, the plans also call for the re-purposing of portions of the existing generation assets, such as the envisioned use of the Honolulu Power Plant as a synchronous condenser to enhance grid security. In other cases, existing generation assets will simply be retired and ultimately removed. In all cases, however, there will be undepreciated plant asset balances at retirement for which a recovery mechanism will need to be agreed.

For a perspective on the magnitude of this issue, Table 5-12 shows the Net Book Value of each plant at which one or more units may be retired as of December 31, 2015, and the 2015 depreciation expense recorded for each.

Generating Station	12/31/2015 Net Book Value	2015 Depreciation Expense
Honolulu Power Plant (including Iwilei Oil Storage)	$51,194,000	$1,643,000
Waiau Power Plant	$178,580,000	$6,073,000
Kahe Power Plant	$201,566,000	$7,271,000

Table 5-12. Hawaiian Electric Power Plant Net Book Value

In addition to the above, for some or all of the retired assets there will be demolition and removal costs which will be charged to accumulated depreciation, some of which may be offset by salvage recoveries.

Securitization

In the PSIP filed in August 2014, net plant balances at retirement were proposed to be converted to a securitized, separately financed asset and amortized over 20 years. This approach remains an option. Securitization would enable these assets to be financed separately from the Companies, through highly rated debt securities issued by a new, bankruptcy remote special purpose entity. The securitization would require legislation to authorize this approach and would result in material financing cost savings to customers, as compared to traditional utility financing.

In addition, there are other potentially viable options that the Companies are exploring. These include options such as the re-use of certain assets or sites for other utility purposes, partial recovery of value through a sale of certain assets, and treating the remaining plant balances as a traditional regulatory asset. In this latter case, there are several ways the amortization schedule could be designed, including applying a variable amortization approach based on customer savings realized, applying an amortization schedule that is aligned with the useful life of the new, efficient replacement generation, or applying a more traditional regulatory asset amortization period. While the Companies have not fully analyzed the applicability or the impact of these or any other potential techniques at this juncture, an analysis of alternatives will be presented in the Updated PSIPs.

Under all of the above options other than securitization and the possible sale of certain assets, while no longer in Utility Plant in Service, the remaining Net Book Value would be included in rate base during the amortization period. This treatment is appropriate for these assets, which entered rate base as prudent, approved investments long ago, and have been maintained and enhanced over the years so as to continue to provide customers with reliable power supply consistent with evolving environmental rules. This generation capacity is needed now and in the future, until such time as a clear replacement strategy for this capacity is agreed and implemented. At that time, the remaining net investment in these prudently managed assets will be appropriate to recover from customers; recognizing a loss on retirement would not be appropriate.

Maui Electric Financial Implications

Differential Revenue Requirements

The differential revenue requirement between the baseline case and an additional case is presented in Figure 5-12 and Figure 5-13.

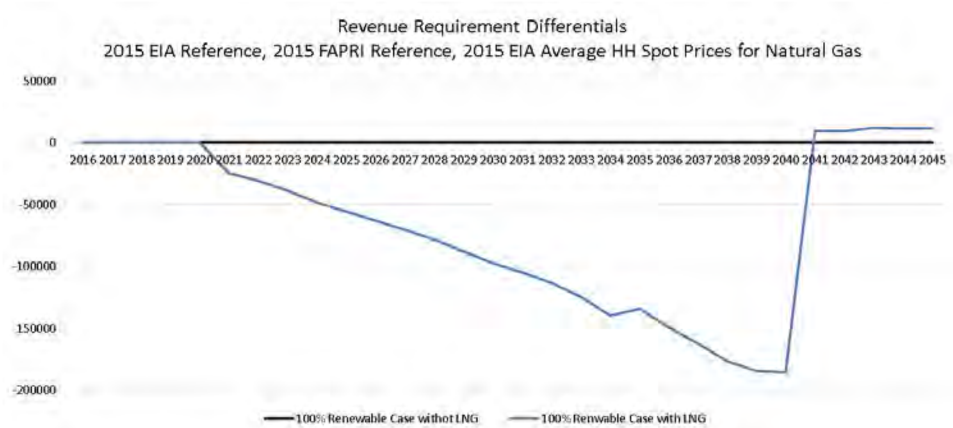

Figure 5-12. Maui Electric Revenue Requirement Differentials: 2015 EIA Reference, 2015 FAPRI Reference, 2015 EIA Average HH Spot Prices for Natural Gas

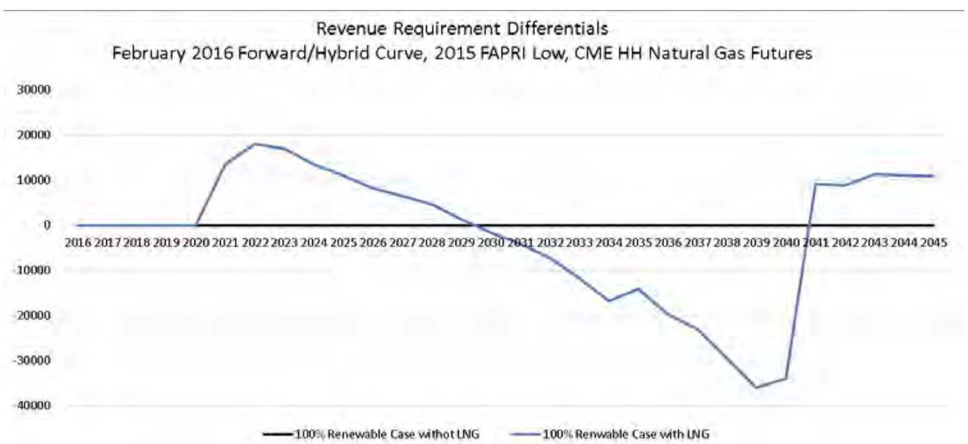

Figure 5-13. Maui Electric Revenue Requirement Differentials: February 2016 Forward/Hybrid Curve, 2015 FAPRI Low, CME HH Natural Gas Futures

The Net Present Value of the differential revenue requirements over the 30 year forecast period are presented in Table 5-12. Note that negative amounts are an improvement over the reference case and provides a benefit to our customers.

Millions $	**Fuel Forecast**	
Case	*February 2016 Forward/Hybrid Curve, 2015 FAPRI Low, CME HH Natural Gas Futures*	*2015 EIA Reference, 2015 FAPRI Reference, 2015 EIA Average HH Spot Prices for Natural Gas*
Case 1 100% Renewable without LNG (Black)	–	–
Case 2 100% Renewable with LNG(Blue)	$17	–$537

Table 5-13. NPV (2016$) of Differential Revenue Requirements for the Maui Electric Cases

These interim results indicate that in a high fuel cost environment, investment in LNG results in significant savings for customers. In a low fuel cost environment, the interim results are less definitive as to the customer savings impact over the forecast period.

Capital Expenditures

The differential impacts on revenue requirements for each case presented above take into account the capital investment differential between each case. Table 5-14 presents the differential capital investment in each 5 year period between Case 1 (the baseline comparison case) and an additional case. Of course, there is no change in capital expenditures between the high and low fuel forecasts.

Millions Nominal $	**Capital Expenditure Differential**						
Case	*2016–2020*	*2021–2025*	*2026–2030*	*2031–2035*	*2036–2040*	*2041–2045*	*Cumulative*
Case 1 100% Renewable without LNG	–	–	–	–	–	–	–
Case 2 100% Renewable with LNG	$109	$43	–	–	–	–	$152

Table 5-14. Maui Electric Capital Expenditure Differential

Removal Costs

The incremental revenue requirement impact analysis presented above does not include any costs for removal costs associated with retired generating units. There will be removal costs and these costs are almost certainly to be in excess of the existing removal regulatory liability balance, but the magnitude and timing of these costs has not yet been determined for each of the cases analyzed. These costs will be incorporated into the Updated PSIPs.

Treatment of Remaining Book Value of Generation Assets at Retirement

The Updated PSIP for Maui Electric will incorporate the retirement of one or more generating units. In some cases, the plans also call for the re-purposing of portions of the existing generation assets. In other cases, existing generation assets will simply be retired and ultimately removed. In all cases, however, there will be undepreciated plant asset balances at retirement for which a recovery mechanism will need to be agreed.

For a perspective on the magnitude of this issue, Table 5-15 shows the Net Book Value of each plant at which one or more units may be retired as of December 31, 2015, and the 2015 depreciation expense recorded for each.

Generating Station	12/31/2015 Net Book Value	2015 Depreciation Expense
Kahalui Power Plant	$5,401,000	$1,444,000
Ma‘alaea Power Plant	$128,880,000	$7,868,000

Table 5-15. Maui Electric Power Plant Net Book Value

In addition to the above, for some or all of the retired assets, there will be demolition and removal costs which will be charged to accumulated depreciation, some of which may be offset by salvage recoveries.

Securitization. Refer to Securitization (page 5-19) for a discussion on how net plant balances were proposed to be converted to a securitized, separately financed asset.

Hawai‘i Electric Light Financial Implications

Differential Revenue Requirements

The differential revenue requirement between the baseline case and an additional case is presented in Figure 5-14 and Figure 5-15.

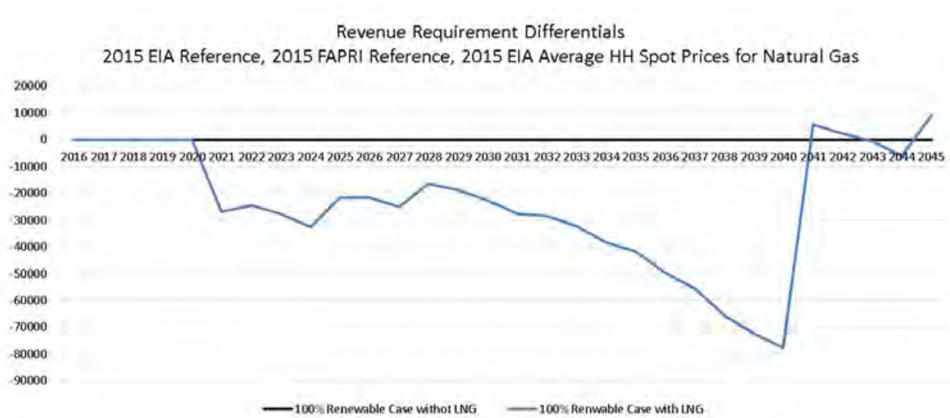

Figure 5-14. Hawai‘i Electric Light Revenue Requirement Differentials: 2015 EIA Reference, 2015 FAPRI Reference, 2015 EIA Average HH Spot Prices for Natural Gas

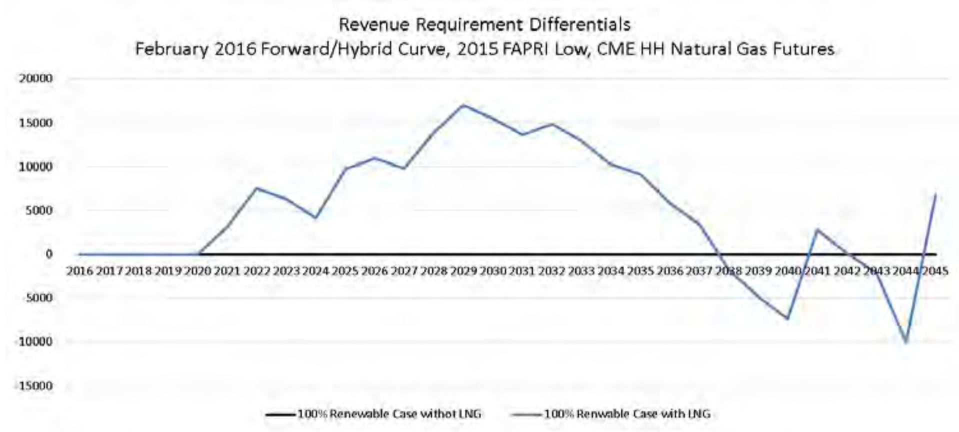

Figure 5-15. Hawai'i Electric Light Revenue Requirement Differentials: February 2016 Forward/Hybrid Curve, 2015 FAPRI Low, CME HH Natural Gas Futures

The Net Present Value of the differential revenue requirements over the 30 year forecast period are presented in Table 5-16. Note that negative amounts are an improvement over the reference case and provides a benefit to our customers.

Millions $	Fuel Forecast	
Case	*February 2016 Forward/Hybrid Curve, 2015 FAPRI Low, CME HH Natural Gas Futures*	*2015 EIA Reference, 2015 FAPRI Reference, 2015 EIA Average HH Spot Prices for Natural Gas*
Case 1 100% Renewable without LNG (Black)	–	–
Case 2 100% Renewable with LNG (Blue)	$55	–$204

Table 5-16. NPV (2016$) of Differential Revenue Requirements for the Hawai'i Electric Light Cases

These interim results indicate that in a high fuel cost environment, investment in LNG results in significant savings for customers. In a low fuel cost environment, the interim results are less definitive as to the customer savings impact over the forecast period.

Capital Expenditures

The differential impacts on revenue requirements for each case presented above take into account the capital investment differential between each case. Table 5-17 presents the differential capital investment in each 5 year period between Case 1 (the baseline comparison case) and an additional case. Of course, there is no change in capital expenditures between the high and low fuel forecasts.

Millions Nominal $	Capital Expenditure Differential						
Case	*2016–2020*	*2021–2025*	*2026–2030*	*2031–2035*	*2036–2040*	*2041–2045*	*Cumulative*
Case 1 100% Renewable without LNG (Black)	–	–	–	–	–	–	–
Case 2 100% Renewable with LNG (Blue)	$101	$25	$0	$0	$0	$0	$127

Table 5-17. Hawai'i Electric Light Capital Expenditures

Removal Costs

The incremental revenue requirement impact analysis presented above does not include any costs for removal costs associated with retired generating units. There will be removal costs and these costs are almost certainly to be in excess of the existing removal regulatory liability balance, but the magnitude and timing of these costs has not yet been determined for each of the cases analyzed. These costs will be incorporated into our ongoing PSIP analysis.

Treatment of Remaining Book Value of Generation Assets at Retirement

The PSIP for Hawai'i Electric Light will incorporate the retirement of one or more generating units. In some cases, the plans also call for the re-purposing of portions of the existing generation assets. In other cases, existing generation assets will simply be retired and ultimately removed. In all cases, however, there will be undepreciated plant asset balances at retirement for which a recovery mechanism will need to be agreed.

For a perspective on the magnitude of this issue, Table 5-18 shows the Net Book Value of each plant at which one or more units may be retired as of December 31, 2015, and the 2015 depreciation expense recorded for each.

Generating Station	12/31/2015 Net Book Value	2015 Depreciation Expense
Kanoelehua Power Plant	$18,372,000	$1,189,000
Keahole Power Plant	$145,580,000	$5,307,000
Puna Steam	$18,355,000	$1,055,000

Table 5-18. Hawai'i Electric Light Power Plant Net Book Value

In addition to the above, for some or all of the retired assets there will be demolition and removal costs which will be charged to accumulated depreciation, some of which may be offset by salvage recoveries.

Securitization. Refer to Securitization (page 5-19) for a discussion on how net plant balances were proposed to be converted to a securitized, separately financed asset.

Consolidated LNG Financial Implications

Using petroleum oil in these units continues our use of this volatile-priced resource with emissions that are subject to increasing environmental restrictions. Figure 5-16 and Figure 5-17 are consolidated charts combining differential revenue requirement for Hawaiian Electric, Hawai'i Electric Light, and Maui Electric comparing combined baseline cases without LNG and consolidated alternative cases with LNG. Both figures show how replacing these fuels with LNG (for both high and low LNG price forecasts) not only appears to lower costs in the future, but also meets stringent emissions standards and significantly reduces emissions, thereby improving Hawai'i's environment.

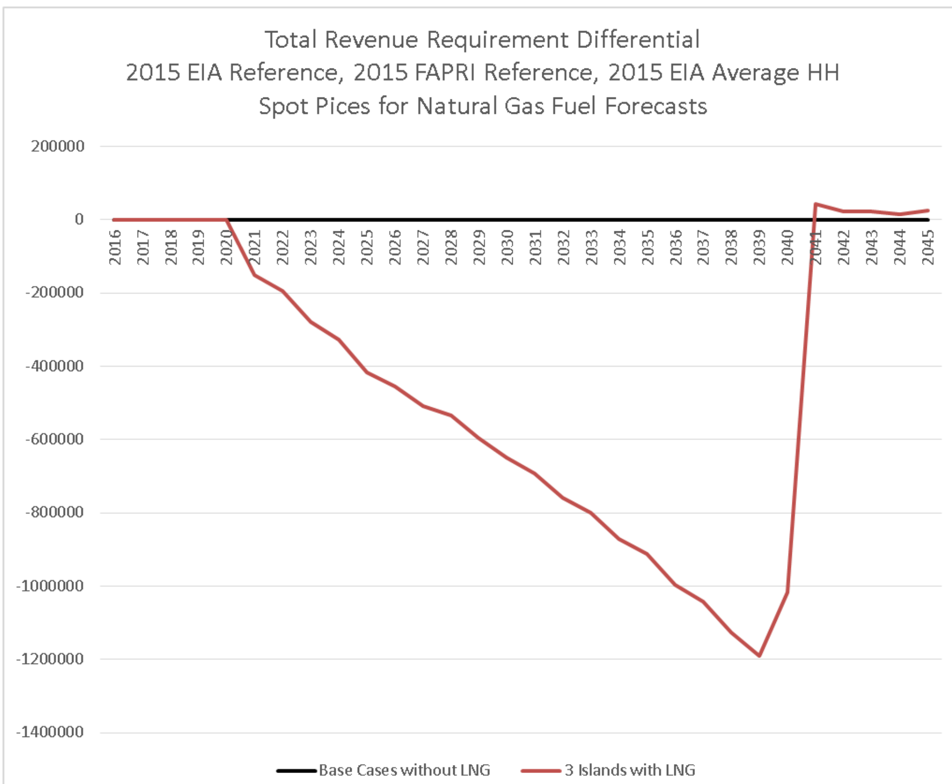

Figure 5-16. Consolidated Revenue Requirement Differential for 2015 EIA Reference, 2015 FAPRI Reference, 2015 EIA Average HH Spot Prices for Natural Gas Fuel Forecasts

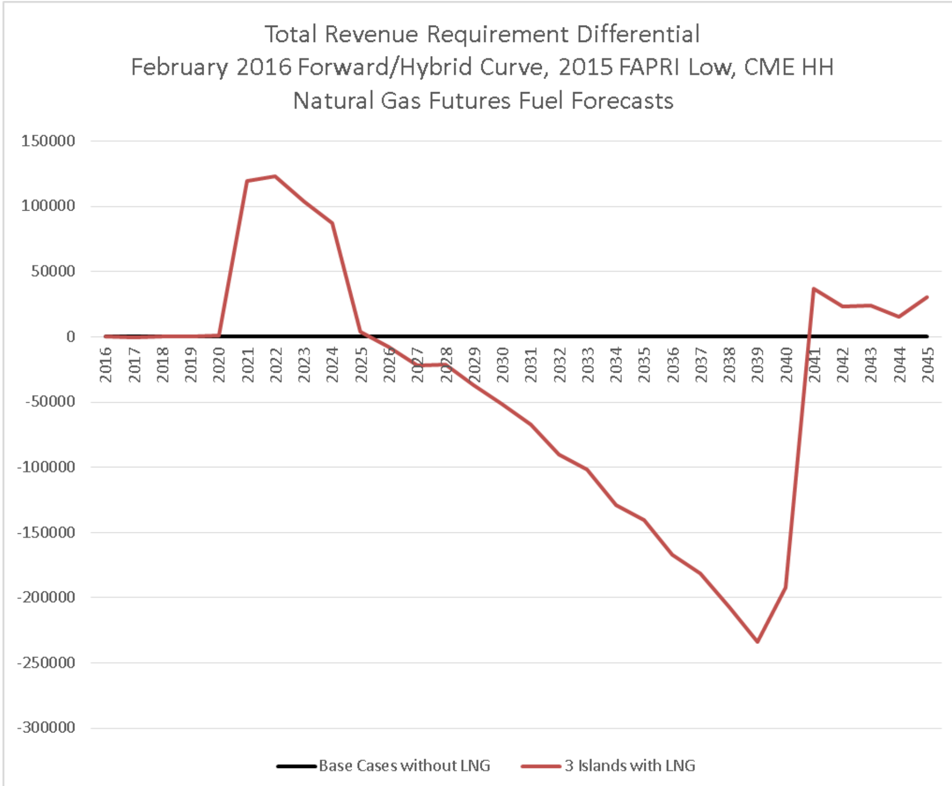

Figure 5-17. Consolidated Revenue Requirement Differential for February 2016 Forward/Hybrid Curve, 2015 FAPRI Low, CME HH Natural Gas Futures Fuel Forecasts

EIGHT OBSERVATIONS AND CONCERNS

We are focused on addressing the Commission's eight Observations and Concerns in a transparent, easy-to-follow manner. Toward that end, we state what we have completed for this PSIP Update Interim Status Report.

Completed for PSIP Update Interim Status Report

#1. Customer Rate and Bill Impacts

For the PSIP Update Interim Status Report, we:

- Developed explicit decision framework and clarified PSIP planning and modeling process.
- Updated all resource costs, fuel costs and resource availability assumptions and shared all relevant assumptions with the Parties.

- Developed multiple initial cases that were specifically designed to iterate towards a low-cost objective, by analyzing the impact of generation modernization and addressing risks associated with changes in fuel price by analyzing both LNG and oil, across a range of fuel price forecasts.
- Ran production simulation at hourly level for initial cases.
- Calculated present value of revenue requirements.
- Calculated relative difference in revenue requirement between cases for initial cases.

#2. Technical Costs and Resource Availability

For the PSIP Update Interim Status Report, we:

- Updated all resource costs (including interconnection costs), fuel costs, and resource availability assumptions.
- Included community-based renewable energy (CBRE) capacity in initial cases.
- Analyzed utility-scale resource cost and availability forecasts, and maximized deployment of most cost-effective resources (solar and wind) in initial cases.
- Used biofuels to provide dispatchable renewable capacity in initial cases as needed to accomplish RPS mandates.

#3. Distributed Energy Resources Integration

For the PSIP Update Interim Status Report, we:

- Developed methodology to optimize DER to achieve lowest system cost while enabling customers to provide cost-effective and reliable grid services.
- Forecasted DER (PV and storage) adoption based on initial case assumptions for retail rate and avoided cost figures (utility-scale PV LCOE for DG-PV export compensation and initial value of storage results based on the DR iterative cycle).
- Developed integration cost methodology for DG-PV and started to apply it and perform calculations on various island systems.

#4. Fossil-Fuel Plant Dispatch and Retirements

For the PSIP Update Interim Status Report, we:

- Analyzed the benefits of generation modernization which includes a flexible 383 MW advanced combined cycle generation.
- Analyzed options to improve operational flexibility and included in initial cases.
- Developed multiple initial cases that were specifically designed to iterate towards a low-cost objective, and address risks associated with changes in fuel price by analyzing both LNG and oil, and analyzing various fuel price forecasts.

- Included preliminary retirement plan in initial cases. Retirement plan is preliminary and subject to further refinement and optimization.

#5. System Security Requirements

The Analytical Methodology (Step 3 in Appendix E) describes how system security requirements are met: we define technology-neutral ancillary services, then determine how much of each service is needed under each resource strategy, and finally identify the lowest reasonable cost to meet system security requirements. This approach ensures that system security requirements do not constrain the resource plans beyond a reasonable transformation period needed to obtain these alternate resources.

#6. Ancillary Services

For the PSIP Update Interim Status Report, we:

- Established operational reliability criteria.
- Designed technology-neutral ancillary services for meeting reliability criteria.
- Determined the amount of ancillary services needed to support the initial cases for O‘ahu.
- Developed initial DR forecast, including DR amounts and load profiles, based on initial case assumptions for DR potential and grid service values.

#7. Inter-Island Transmission

We have developed capital cost assumptions for two off-O‘ahu resources utilizing a cable inter-island transmission. We have not, however, started our analysis for inter-island transmission.

#8. Customer and Implementation Risks

For the PSIP Update Interim Status Report, we:

- Developed multiple initial cases that were specifically designed to iterate towards a low-cost objective by analyzing the impact of generation modernization and addressing risks associated with changes in fuel price by analyzing both LNG and oil, and analyzing various fuel price forecasts.
- Ran production simulation at hourly level for initial cases.
- Calculated present value of revenue requirements.
- Calculated relative difference in revenue requirement between cases for initial cases.
- Developed initial Grid Defection methodology

6. Next Steps

For our PSIP Update Interim Status Report, we designed and analyzed a number of cases. For our 2016 Updated PSIPs, we plan to continue our analysis on these cases, plus design additional cases necessary to thoroughly arrive at a series of alternative plans, then select our preferred plans and create complementary five-year action plans.

FURTHER ANALYSES AND EVALUATION

Next Steps Toward the Updated PSIPs

Presented here are the actions we plan to take to adequately respond to the eight Observations and Concerns for our 2016 Updated PSIPs.

#1. Customer Rate and Bill Impacts

For our 2016 Updated PSIPs, we plan to:

- Complete analysis of cases where DER is maximized and with and without generation modernization.
- Refine cases to:
  - Incorporate results from preceding runs of DER, utility-scale, DR iterative cycles.
  - Iterate to achieve objectives of lowest cost and minimized risks.
  - Analyze grid modernization to characterize tradeoffs and risks of capital investments.
- Run production simulation at sub-hourly level to refine the cases.
- Analyze “all-in” cost and rate impact of refined cases both near-term (till 2020) and long-term (through 2045).

- Conduct stochastic analysis to characterize risks associated with fuel price forecasts.
- Low-cost, minimized risks will be the primary objective. In addition, list other considerations and metrics of interest including renewable content above and beyond RPS and total cost including non-electric system costs like tax credits and customer investments.
- Run sensitivity analyses with critical uncertainty variables (for example, fuel cost and resource cost).
- Assess risk (including fuel price risk) and propose mitigations for refined cases.

#2. Technical Costs and Resource Availability

For our 2016 Updated PSIPs, we plan to:

- Review the results of the NREL review of our new resource assumptions and their analysis of the resource constraints for wind and solar PV by island and make changes as appropriate based on NREL's reports.
- Compare cost forecasts of energy storage and biofuels and develop optimized-mix of these dispatchable resources in refined cases.
- Analyze offshore wind for inclusion in refined cases
- Analyze inter-island interconnection between islands such as Maui and O'ahu to enable additional utility-scale renewable resources in refined cases.
- Conduct "Pathways to 2045" study on the use of electricity and hydrogen (created by electrolysis) to power vehicles. Include study results in refined cases.
- Analyze energy storage.

#3. Distributed Energy Resources Integration

For our 2016 Updated PSIPs, we plan to:

- Calculate updated retail rate and time-of-use (TOU) forecasts for the planning period based on production simulations and DR iterative cycle results.
- Finalize integration cost methodology, apply methodology to the various island systems, and incorporate the integration costs into the DER adoption forecast.
- Refine DER (PV, PV + storage, and standalone storage) adoption forecast based on updated customer economics driven by updated retail prices, TOU rates, avoided costs, and integration costs.
- Complete optimal renewable energy portfolio plans.
- Identify cost-effective opportunities to retrofit and upgrade existing DER.
- Develop and analyze a candidate plan regarding maximum DER integration.

#4. Fossil-Fuel Plant Dispatch and Retirements

For our 2016 Updated PSIPs, we plan to:

- Refine cases to incorporate results from preceding runs of DER, utility-scale, and DR iterative cycles; iterate to achieve objectives of lowest cost and minimized risks; and analyze grid modernization to characterize tradeoffs and risks of capital investments.
- Refine and optimize retirement plan for inclusion in refined cases.
- Complete Fossil Generation Retirement Plan.
- Run sensitivity analyses with critical uncertainty variables (for example, fuel and resource costs).
- Assess risk (including fuel cost risk and technology risk) and propose mitigations for refined cases.
- Review and clarify Companies' environmental compliance strategies.
- Complete Environmental Compliance Plan.
- Complete Key Generator Utilization Plan.
- Review economic dispatch policies for each system and clarify dispatch of units using renewable fuels.
- Complete Generation Commitment and Economic Dispatch Review.

#5. System Security Requirements

For our 2016 Updated PSIPs, our next steps are to apply the Analysis Methodology (outlined in Chapter 3) to all the resource plans for each island power grid.

#6. Ancillary Services

For our 2016 Updated PSIPs, we plan to:

- Iterate through DR analysis to develop refined DR forecast, including DR amounts and load profiles, based on the refined cases.
- Determine the amount of ancillary services needed to support the refined cases for all islands.
- Find lowest reasonable cost solution considering all types of qualified resources for refined cases for all islands.
- Identify flexible planning and future analyses to optimize over time.
- Complete Must-Run Generation Reduction Plan.
- Complete Generation Flexibility Plan.
- Analyze energy storage resource options and develop optimal, cost-effective deployment of energy storage for refined cases.

- Analyze system-level hosting capacity limits and include in refined cases.

#7. Inter-Island Transmission

For our 2016 Updated PSIPs, we plan to analyze inter-island transmission considering, among other things, alternative assumptions about fuel costs, inter-island cable costs, and renewable energy costs.

#8. Customer and Implementation Risks

For our 2016 Updated PSIPs, we plan to:

- Refine cases to incorporate results from preceding runs of DER, utility-scale, DR iterative cycles; iterate to achieve objectives of lowest cost and minimized risk; and analyze grid modernization to characterize tradeoffs and risks of capital investments.
- Conduct stochastic analysis to characterize risks associated with fuel price forecasts.
- Run sensitivity analyses with critical uncertainty variables (for example, fuel and resource costs).
- Assess risk (including fuel cost risk and technology cost risk) and propose mitigations for refined cases.
- Finalize Grid Defection methodology and assess tipping points by key input parameters by customer segments and island systems.
- Develop five-year action plans to implement the Preferred Plans.

Component Plans

Integrated throughout our planning and analysis, we are working toward satisfying the requirements stated in each of the following component plans for our operating utilities:

- *Fossil Generation Retirement Plan:* Hawaiian Electric and Hawai'i Electric Light
- *Generation Flexibility Plan:* Hawaiian Electric, Hawai'i Electric Light, and Maui Electric
- *Must-Run Generation Reduction Plan:* Hawaiian Electric and Hawai'i Electric Light
- *Environmental Compliance Plan:* Hawaiian Electric
- *Key Generator Utilization Plan:* Hawaiian Electric
- *Optimal Renewable Energy Portfolio Plan:* Hawaiian Electric and Maui Electric
- *Generation Commitment and Economic Dispatch Review:* Hawaiian Electric, Hawai'i Electric Light, and Maui Electric

Overall, we plan to continue to address each of these plans, summarize our results, and demonstrate how we have complied with the Commission's directives.

Fossil Generation Retirement Plan

The initial cases for Hawaiian Electric includes retirement of some existing fossil generation which will be used as the starting point for refining upcoming iterations of the analysis. We will also include the retirement plans for Hawai'i Electric Light and Maui Electric in the next iterations of the analysis.

Generation Flexibility Plan

We have already increased, and plan to continue to increase the flexibility of existing generators. The generation flexibility required of existing and future resources will be evaluated in the analysis as it is dependent on the resource mix of the various plans.

Must-Run Generation Reduction Plan

The Companies have already reduced, and plan to continue to reduce must-run generation as the systems change. We will address this through the analysis.

Environmental Compliance Plan

Complying with environmental regulations is a requirement—not an option. The current environmental compliance plans include switching to lower emission fuels. The retirement of existing generation identified in the Fossil Generation Retirement Plan will also be a means of addressing this Environmental Compliance Plan.

Key Generator Utilization Plan

This plan is interrelated with addressing the Fossil Generation Retirement Plan, the Generation Flexibility Plan, the Must-Run Generation Reduction Plan, the Environmental Compliance Plan, and the Optimal Renewable Energy Portfolio Plan.

Optimal Renewable Energy Portfolio Plan

We are addressing this plan through the Analysis Methodology (outlined in Chapter 3).

Generation Commitment and Economic Dispatch Review

We will review this plan and complete it as part of the Updated PSIPs filing.

FIVE-YEAR ACTION PLAN

Our analysis will identify a number of alternative plans. From these, we will create a preferred plan for each operating utility that attains 100% renewable generation by 2045, is cost-effective, and maintains system reliability. It will be the outcome of our rigorous analyses, providing a path toward achieving our renewable goals.

We plan to create an executable action plan that accompanies each of those preferred plans. These plans will outline the steps necessary to implement our preferred plans over the next five years. During that time, we will continually evaluate new developments and, as necessary, alter our direction to keep on course.

A. Modeling Assumptions Data

FUEL SUPPLY AND PRICE FORECASTS

This appendix contains fuel supply price forecasts for each of the three operating utilities (Table A-19 through Table A-24). These prices are based on the 2015 EIA Reference, the 2015 FAPRI Reference and 2015 FAPRI Low, and the February 2016 Forward/Hybrid Curve for the years 2016 through 2045.

LNG forecasted prices (Table A-19 through Table A-24) were derived from 2015 EIA Average Henry Hub Spot Prices for Natural Gas as a "reference case," and the February 2016 Forward/Hybrid forecast used the Chicago Mercantile Exchange Henry Hub Natural Gas Futures. These LNG costs also represent the variable costs, which includes the gas commodity, taxes, port fees, wharfage, stevedoring and other ancillary delivery service charges. Table A-25and Table A-26 are the total nominal LNG costs, inclusive of fixed and variable costs. Fixed costs include liquefaction, pipeline tolls (for tariff service), and shipping charges.

Hawaiian Electric Fuel Forecasted Fuel Prices—2015 Nominal Dollars

$/MMBtu	Hawaiian Electric Fuel Price Forecasts						
	2015 EIA Reference						*2015 FAPRI Reference*
Year	LSFO	Diesel	70% LSFO/ 30% Diesel	ULSD	40% LSFO/ 60% ULSD	LNG	Biodiesel
2016	$13.65	$16.29	$14.41	$17.39	$15.82	n/a	$32.81
2017	$14.92	$17.63	$15.70	$18.77	$17.16	n/a	$34.13
2018	$15.18	$17.94	$15.98	$19.10	$17.46	n/a	$34.95
2019	$15.76	$18.58	$16.57	$19.77	$18.09	n/a	$35.46
2020	$16.34	$19.21	$17.17	$20.43	$18.72	n/a	$35.77
2021	$17.07	$20.00	$17.92	$21.25	$19.50	$8.93	$36.79
2022	$17.86	$20.85	$18.72	$22.13	$20.34	$8.48	$37.20
2023	$18.69	$21.73	$19.57	$23.05	$21.22	$8.77	$37.61
2024	$19.54	$22.65	$20.44	$24.00	$22.13	$9.00	$38.12
2025	$20.44	$23.61	$21.35	$24.99	$23.09	$9.26	$38.60
2026	$21.41	$24.64	$22.34	$26.06	$24.11	$9.63	$39.14
2027	$22.42	$25.73	$23.38	$27.19	$25.19	$9.78	$39.67
2028	$23.49	$26.87	$24.47	$28.37	$26.33	$9.94	$40.21
2029	$24.62	$28.06	$25.61	$29.61	$27.52	$10.15	$40.74
2030	$25.81	$29.33	$26.83	$30.92	$28.78	$10.30	$41.27
2031	$27.09	$30.69	$28.12	$32.33	$30.13	$10.73	$41.81
2032	$28.42	$32.11	$29.48	$33.79	$31.54	$11.13	$42.34
2033	$29.83	$33.59	$30.91	$35.33	$33.03	$11.54	$42.88
2034	$31.24	$35.09	$32.35	$36.89	$34.52	$11.96	$43.41
2035	$32.76	$36.70	$33.89	$38.55	$36.12	$12.35	$43.95
2036	$34.36	$38.40	$35.53	$40.31	$37.82	$12.76	$44.48
2037	$36.00	$40.13	$37.19	$42.09	$39.54	$13.10	$45.01
2038	$37.80	$42.03	$39.02	$44.06	$41.44	$13.57	$45.55
2039	$39.81	$44.15	$41.06	$46.25	$43.55	$14.31	$46.08
2040	$41.78	$46.24	$43.07	$48.41	$45.63	$15.24	$46.62
2041	$43.86	$48.43	$45.18	$50.67	$47.82	n/a	$47.16
2042	$46.04	$50.72	$47.39	$53.04	$50.10	n/a	$47.70
2043	$48.32	$53.12	$49.71	$55.52	$52.50	n/a	$48.26
2044	$50.73	$55.64	$52.14	$58.11	$55.02	n/a	$48.82
2045	$53.25	$58.27	$54.70	$60.82	$57.65	n/a	$49.38

Table A-19. Hawaiian Electric Fuel Price Forecasts (1 of 2)

Hawaiian Electric Fuel Forecasted Fuel Prices—2016 Nominal Dollars

$/MMBtu	Hawaiian Electric Fuel Price Forecasts						
	Feb 2016 Forward/Hybrid Curve						*2015 FAPRI Low*
Year	LSFO	Diesel	70% LSFO/ 30% Diesel	ULSD	40% LSFO/ 60% ULSD	LNG	Biodiesel
2016	$6.71	$9.22	$7.44	$10.16	$8.71	n/a	$23.80
2017	$7.87	$10.44	$8.61	$11.42	$9.93	n/a	$23.21
2018	$8.70	$11.33	$9.46	$12.35	$10.82	n/a	$24.33
2019	$9.39	$12.08	$10.17	$13.12	$11.56	n/a	$25.36
2020	$9.84	$12.58	$10.63	$13.65	$12.05	n/a	$26.08
2021	$10.28	$13.07	$11.08	$14.16	$12.54	$7.03	$26.85
2022	$10.59	$13.43	$11.41	$14.54	$12.89	$6.60	$27.13
2023	$10.96	$13.85	$11.80	$14.98	$13.30	$6.82	$27.10
2024	$11.35	$14.28	$12.19	$15.43	$13.72	$7.04	$27.09
2025	$11.74	$14.72	$12.60	$15.90	$14.16	$7.28	$27.20
2026	$12.16	$15.19	$13.03	$16.39	$14.62	$7.52	$27.32
2027	$12.60	$15.68	$13.49	$16.90	$15.10	$7.78	$27.39
2028	$13.06	$16.20	$13.97	$17.45	$15.61	$8.06	$27.25
2029	$13.55	$16.74	$14.47	$18.02	$16.14	$8.28	$27.09
2030	$14.06	$17.31	$15.00	$18.62	$16.71	$8.50	$26.86
2031	$14.61	$17.92	$15.56	$19.26	$17.31	$8.74	$26.68
2032	$15.18	$18.56	$16.15	$19.93	$17.94	$8.99	$26.40
2033	$15.77	$19.23	$16.77	$20.63	$18.59	$9.24	$26.23
2034	$16.39	$19.91	$17.40	$21.35	$19.27	$9.51	$26.06
2035	$17.03	$20.63	$18.07	$22.10	$19.97	$9.78	$25.90
2036	$17.70	$21.37	$18.76	$22.88	$20.71	$10.07	$25.70
2037	$18.40	$22.15	$19.48	$23.69	$21.47	$10.36	$25.49
2038	$19.13	$22.96	$20.24	$24.54	$22.28	$10.67	$25.33
2039	$19.91	$23.82	$21.03	$25.44	$23.12	$10.99	$25.08
2040	$20.71	$24.71	$21.86	$26.37	$24.00	$11.33	$24.92
2041	$21.55	$25.63	$22.72	$27.33	$24.91	n/a	$24.76
2042	$22.41	$26.58	$23.55	$28.33	$25.85	n/a	$24.60
2043	$23.32	$27.58	$24.41	$29.37	$26.83	n/a	$24.44
2044	$24.26	$28.60	$25.31	$30.44	$27.85	n/a	$24.28
2045	$25.24	$29.67	$26.23	$31.56	$28.91	n/a	$24.13

Table A-20. Hawaiian Electric Fuel Price Forecasts (2 of 2)

Maui Electric Fuel Forecasted Fuel Prices—2015 Nominal Dollars

$/MMBtu	Maui Electric Fuel Price Forecasts						
	2015 EIA Reference						*2015 FAPRI Reference*
Year	MSFO	Diesel	ULSD (Maui)	ULSD (Moloka'i)	ULSD (Lana'i)	LNG	Biodiesel
2016	$11.46	$17.31	$18.06	$18.99	$21.87	n/a	$33.46
2017	$12.55	$18.80	$19.59	$20.52	$23.43	n/a	$34.82
2018	$12.77	$19.13	$19.93	$20.88	$23.84	n/a	$35.65
2019	$13.26	$19.83	$20.65	$21.61	$24.62	n/a	$36.17
2020	$13.76	$20.52	$21.37	$22.34	$25.40	n/a	$36.49
2021	$14.39	$21.40	$22.27	$23.25	$26.35	$11.32	$37.53
2022	$15.06	$22.33	$23.23	$24.21	$27.35	$10.91	$37.94
2023	$15.76	$23.31	$24.23	$25.22	$28.41	$11.24	$38.36
2024	$16.50	$24.32	$25.28	$26.27	$29.49	$11.52	$38.88
2025	$17.26	$25.38	$26.36	$27.37	$30.63	$11.81	$39.38
2026	$18.09	$26.52	$27.54	$28.55	$31.85	$12.23	$39.92
2027	$18.96	$27.72	$28.77	$29.78	$33.13	$12.42	$40.47
2028	$19.88	$28.98	$30.07	$31.08	$34.48	$12.63	$41.01
2029	$20.84	$30.31	$31.43	$32.45	$35.89	$12.88	$41.56
2030	$21.86	$31.71	$32.88	$33.90	$37.38	$13.08	$42.10
2031	$22.95	$33.21	$34.42	$35.44	$38.97	$13.56	$42.64
2032	$24.10	$34.78	$36.04	$37.06	$40.64	$14.01	$43.19
2033	$25.30	$36.43	$37.73	$38.76	$42.39	$14.46	$43.73
2034	$26.51	$38.10	$39.44	$40.47	$44.15	$14.93	$44.28
2035	$27.81	$39.88	$41.28	$42.30	$46.03	$15.38	$44.82
2036	$29.18	$41.76	$43.21	$44.24	$48.02	$15.84	$45.37
2037	$30.58	$43.68	$45.18	$46.21	$50.04	$16.23	$45.91
2038	$32.12	$45.79	$47.35	$48.38	$52.26	$16.76	$46.46
2039	$33.85	$48.15	$49.77	$50.79	$54.73	$17.55	$47.00
2040	$35.54	$50.47	$52.15	$53.17	$57.17	$18.53	$47.55
2041	$37.32	$52.90	$54.65	$55.67	$59.72	n/a	$48.10
2042	$39.19	$55.45	$57.27	$58.28	$62.39	n/a	$48.66
2043	$41.15	$58.12	$60.01	$61.01	$65.17	n/a	$49.22
2044	$43.21	$60.92	$62.89	$63.87	$68.08	n/a	$49.79
2045	$45.37	$63.86	$65.90	$66.87	$71.11	n/a	$50.37

Table A-21. Maui Electric Fuel Price Forecasts (1 of 2)

Maui Electric Fuel Forecasted Fuel Prices—2016 Nominal Dollars

$/MMBtu	Maui Electric Fuel Price Forecasts						
	Feb 2016 Forward/Hybrid Curve						*2015 FAPRI Low*
Year	MSFO	Diesel	ULSD (Maui)	ULSD (Moloka'i)	ULSD (Lana'i)	LNG	Biodiesel
2016	$5.49	$9.36	$9.92	$11.00	$14.01	n/a	$23.80
2017	$6.48	$10.71	$11.31	$12.39	$15.43	n/a	$23.21
2018	$7.19	$11.70	$12.33	$13.41	$16.49	n/a	$24.33
2019	$7.78	$12.52	$13.18	$14.27	$17.40	n/a	$25.36
2020	$8.16	$13.06	$13.74	$14.84	$18.02	n/a	$26.08
2021	$8.53	$13.60	$14.29	$15.41	$18.64	$9.43	$26.85
2022	$8.80	$13.99	$14.70	$15.82	$19.10	$9.04	$27.13
2023	$9.11	$14.44	$15.16	$16.31	$19.62	$9.30	$27.10
2024	$9.44	$14.90	$15.64	$16.80	$20.16	$9.57	$27.09
2025	$9.77	$15.39	$16.15	$17.31	$20.72	$9.84	$27.20
2026	$10.13	$15.89	$16.67	$17.85	$21.30	$10.13	$27.32
2027	$10.50	$16.43	$17.22	$18.41	$21.92	$10.43	$27.39
2028	$10.89	$16.99	$17.80	$19.01	$22.56	$10.76	$27.25
2029	$11.30	$17.58	$18.41	$19.63	$23.24	$11.02	$27.09
2030	$11.74	$18.20	$19.06	$20.30	$23.96	$11.30	$26.86
2031	$12.20	$18.87	$19.75	$21.00	$24.73	$11.58	$26.68
2032	$12.69	$19.56	$20.46	$21.73	$25.52	$11.88	$26.40
2033	$13.19	$20.29	$21.21	$22.50	$26.35	$12.18	$26.23
2034	$13.72	$21.03	$21.99	$23.29	$27.21	$12.50	$26.06
2035	$14.26	$21.81	$22.79	$24.11	$28.10	$12.82	$25.90
2036	$14.83	$22.62	$23.63	$24.97	$29.03	$13.16	$25.70
2037	$15.43	$23.47	$24.51	$25.87	$29.99	$13.51	$25.49
2038	$16.05	$24.36	$25.42	$26.80	$30.99	$13.87	$25.33
2039	$16.71	$25.29	$26.39	$27.79	$32.06	$14.25	$25.08
2040	$17.39	$26.26	$27.39	$28.81	$33.16	$14.64	$24.92
2041	$18.10	$27.27	$28.43	$29.87	$34.29	n/a	$24.76
2042	$18.84	$28.31	$29.51	$30.96	$35.47	n/a	$24.60
2043	$19.61	$29.40	$30.63	$32.10	$36.68	n/a	$24.44
2044	$20.42	$30.53	$31.79	$33.28	$37.94	n/a	$24.28
2045	$21.25	$31.70	$33.00	$34.51	$39.24	n/a	$24.13

Table A-22. Maui Electric Fuel Price Forecasts (2 of 2)

Hawai‘i Electric Light Fuel Forecasted Fuel Prices—2015 Nominal Dollars

$/MMBtu	Hawai‘i Electric Light Fuel Price Forecasts					
	2015 EIA Reference					*2015 FAPRI Reference*
Year	MSFO	Diesel	ULSD	Naptha	LNG	Biodiesel
2016	$11.81	$17.47	$17.99	$18.46	n/a	$33.79
2017	$12.91	$18.92	$19.48	$19.85	n/a	$35.16
2018	$13.14	$19.25	$19.82	$20.20	n/a	$36.00
2019	$13.64	$19.94	$20.52	$20.88	n/a	$36.53
2020	$14.14	$20.62	$21.23	$21.55	n/a	$36.84
2021	$14.78	$21.47	$22.10	$22.39	$11.54	$37.90
2022	$15.46	$22.39	$23.04	$23.28	$11.13	$38.32
2023	$16.18	$23.34	$24.02	$24.21	$11.47	$38.74
2024	$16.92	$24.33	$25.03	$25.17	$11.75	$39.26
2025	$17.69	$25.36	$26.09	$26.17	$12.06	$39.76
2026	$18.53	$26.48	$27.23	$27.25	$12.47	$40.31
2027	$19.42	$27.65	$28.43	$28.39	$12.67	$40.86
2028	$20.34	$28.88	$29.69	$29.58	$12.88	$41.41
2029	$21.32	$30.17	$31.02	$30.83	$13.15	$41.96
2030	$22.35	$31.54	$32.42	$32.15	$13.34	$42.51
2031	$23.46	$33.01	$33.92	$33.56	$13.83	$43.06
2032	$24.62	$34.54	$35.49	$35.04	$14.28	$43.61
2033	$25.83	$36.15	$37.14	$36.59	$14.75	$44.16
2034	$27.06	$37.76	$38.80	$38.15	$15.22	$44.71
2035	$28.38	$39.50	$40.58	$39.83	$15.67	$45.26
2036	$29.77	$41.34	$42.46	$41.59	$16.14	$45.81
2037	$31.19	$43.20	$44.37	$43.39	$16.54	$46.36
2038	$32.75	$45.26	$46.48	$45.36	$17.07	$46.91
2039	$34.49	$47.55	$48.82	$47.56	$17.87	$47.46
2040	$36.21	$49.80	$51.13	$49.73	$18.86	$48.02
2041	$38.01	$52.17	$53.56	$52.00	n/a	$48.57
2042	$39.90	$54.65	$56.09	$54.37	n/a	$49.13
2043	$41.88	$57.24	$58.75	$56.85	n/a	$49.70
2044	$43.96	$59.96	$61.53	$59.45	n/a	$50.28
2045	$46.15	$62.81	$64.45	$62.16	n/a	$50.86

Table A-23. Hawai‘i Electric Light Fuel Price Forecasts (1 of 2)

Hawai'i Electric Light Fuel Forecasted Fuel Prices—2016 Nominal Dollars

$/MMBtu	Hawai'i Electric Light Fuel Price Forecasts					
	Feb 2016 Forward/Hybrid Curve					*2015 FAPRI Reference*
Year	MSFO	Diesel	ULSD	Naptha	LNG	Biodiesel
2016	$5.79	$9.82	$10.17	$11.33		$24.52
2017	$6.79	$11.13	$11.52	$12.60		$23.91
2018	$7.51	$12.10	$12.51	$13.54		$25.06
2019	$8.11	$12.90	$13.33	$14.33		$26.12
2020	$8.50	$13.44	$13.89	$14.87		$26.86
2021	$8.88	$13.97	$14.43	$15.40	$9.65	$27.66
2022	$9.15	$14.36	$14.83	$15.80	$9.27	$27.94
2023	$9.47	$14.81	$15.29	$16.25	$9.53	$27.91
2024	$9.80	$15.27	$15.76	$16.72	$9.80	$27.91
2025	$10.15	$15.75	$16.25	$17.20	$10.09	$28.02
2026	$10.51	$16.25	$16.77	$17.71	$10.38	$28.14
2027	$10.89	$16.78	$17.31	$18.24	$10.68	$28.21
2028	$11.29	$17.33	$17.88	$18.80	$11.02	$28.07
2029	$11.71	$17.92	$18.48	$19.39	$11.28	$27.90
2030	$12.15	$18.53	$19.12	$20.01	$11.56	$27.67
2031	$12.63	$19.19	$19.79	$20.67	$11.85	$27.48
2032	$13.12	$19.88	$20.50	$21.36	$12.15	$27.20
2033	$13.64	$20.59	$21.23	$22.08	$12.46	$27.02
2034	$14.17	$21.33	$21.99	$22.82	$12.78	$26.84
2035	$14.73	$22.10	$22.78	$23.59	$13.12	$26.68
2036	$15.31	$22.91	$23.61	$24.40	$13.46	$26.47
2037	$15.91	$23.74	$24.47	$25.24	$13.81	$26.25
2038	$16.55	$24.62	$25.36	$26.11	$14.18	$26.09
2039	$17.22	$25.54	$26.31	$27.03	$14.57	$25.83
2040	$17.92	$26.50	$27.29	$27.99	$14.96	$25.67
2041	$18.64	$27.49	$28.31	$27.99		$25.50
2042	$19.39	$28.52	$29.37	$27.99		$25.34
2043	$20.18	$29.59	$30.47	$27.99		$25.17
2044	$20.99	$30.70	$31.61	$27.99		$25.01
2045	$21.84	$31.85	$32.78	$27.99		$24.85

Table A-24. Hawai'i Electric Light Fuel Price Forecasts (2 of 2)

Hawaiian Electric Fuel Price Forecasts (Nominal Dollars)

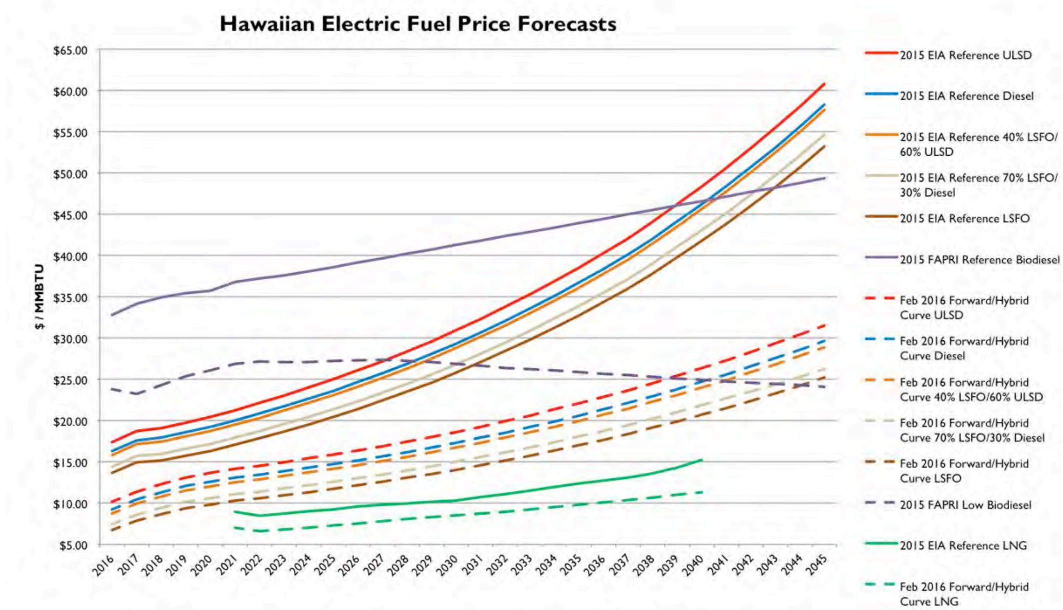

Figure A-18. Hawaiian Electric Fuel Price Forecasts

Hawaiian Electric 2015 EIA Reference Fuel Price Forecasts (Nominal Dollars)

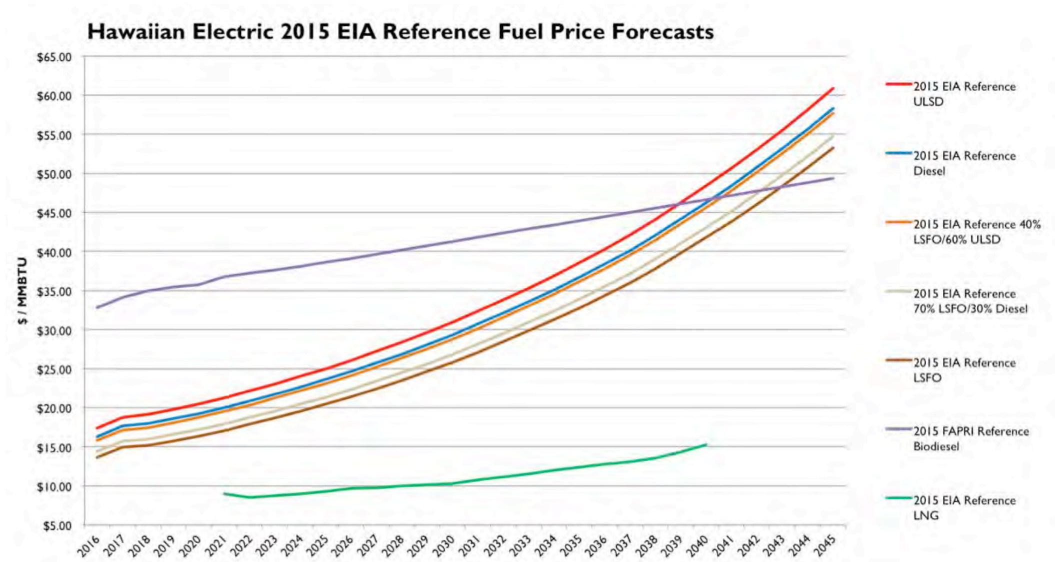

Figure A-19. Hawaiian Electric 2015 EIA Reference Fuel Price Forecasts

Hawaiian Electric February 2016 Forward/Hybrid Curve Fuel Price Forecasts (Nominal Dollars)

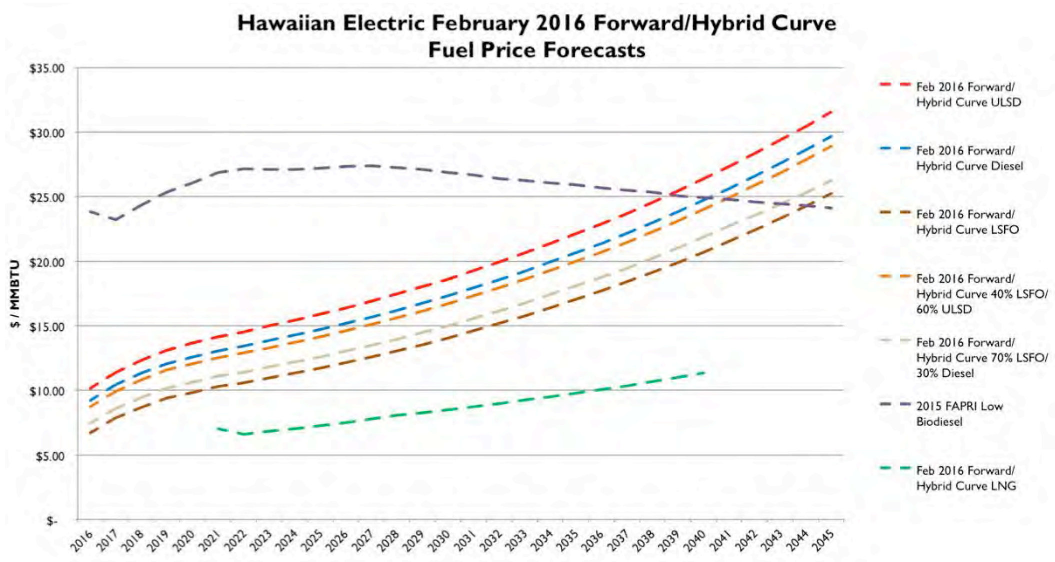

Figure A-20. Hawaiian Electric February 2016 Forward/Hybrid Curve Fuel Price Forecasts

Maui Electric Fuel Price Forecasts (Nominal Dollars)

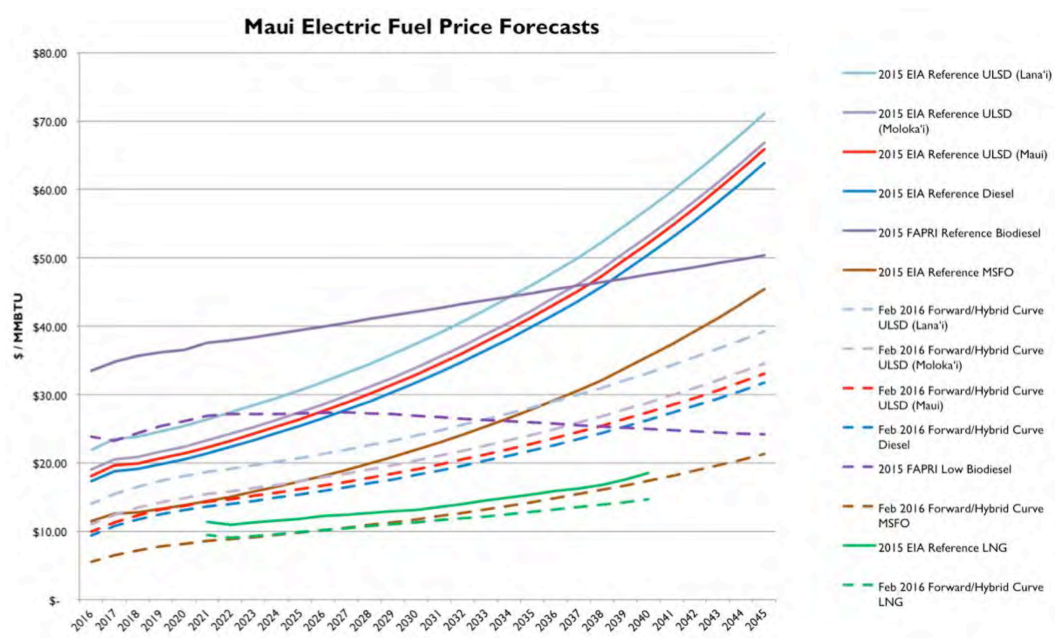

Figure A-21. Maui Electric Fuel Price Forecasts

Maui Electric 2015 EIA Reference Fuel Price Forecasts (Nominal Dollars)

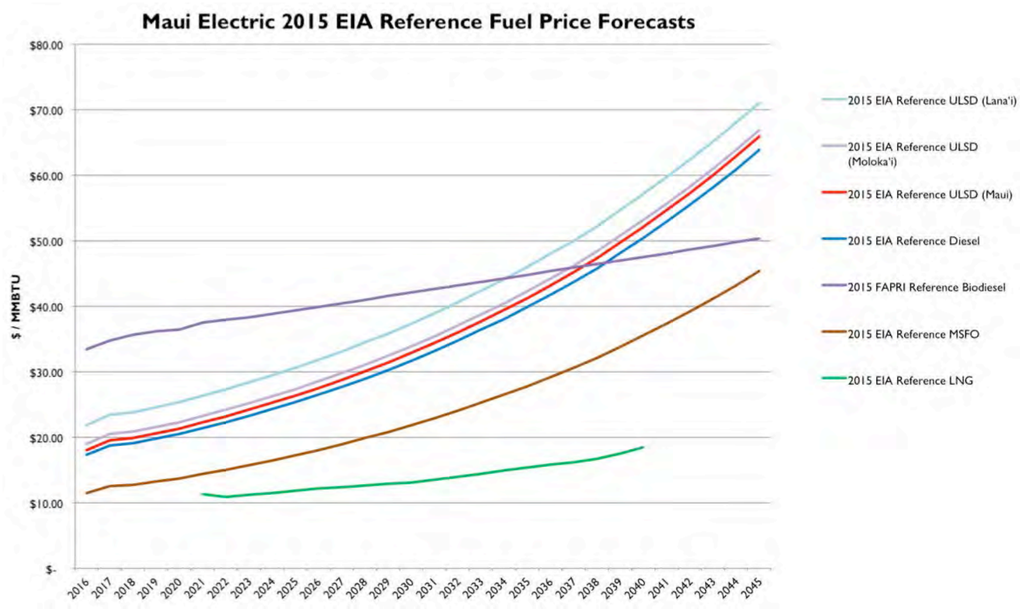

Figure A-22. Maui Electric 2015 EIA Reference Fuel Price Forecasts

Maui Electric February 2016 Forward/Hybrid Curve Fuel Price Forecasts (Nominal Dollars)

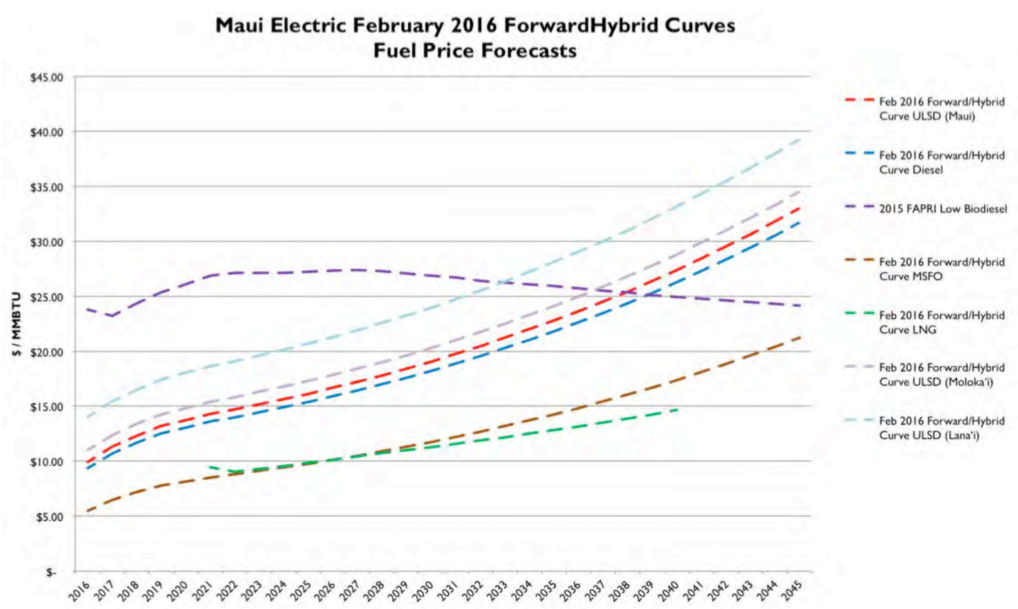

Figure A-23. Maui Electric February 2016 Forward/Hybrid Curve Fuel Price Forecasts

Hawai‘i Electric Light Fuel Price Forecasts (Nominal Dollars)

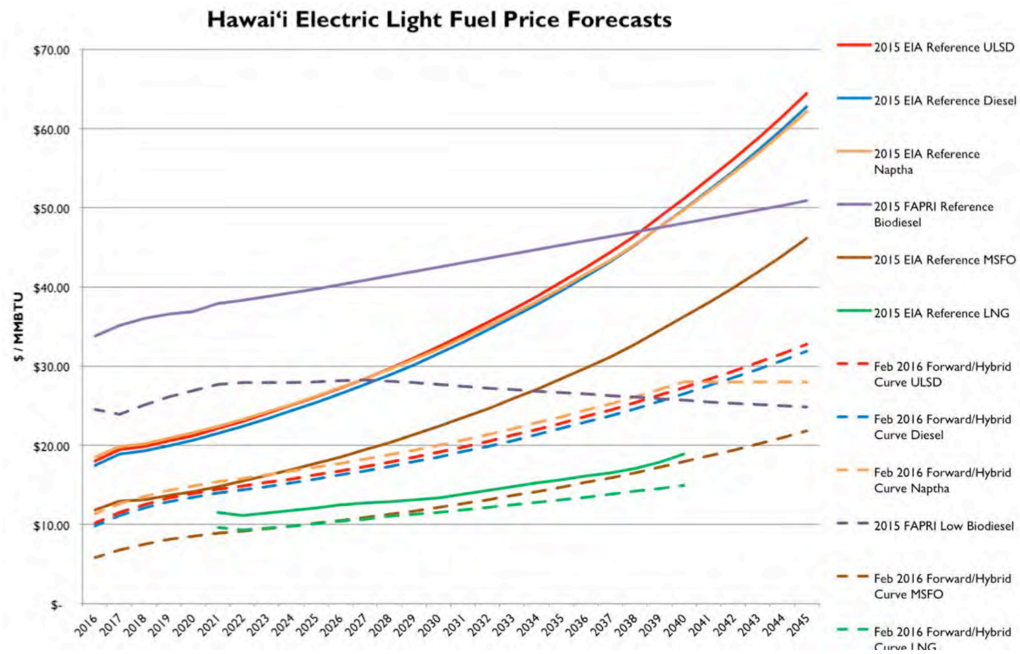

Figure A-24. Hawai‘i Electric Light Fuel Price Forecasts

Hawai‘i Electric Light 2015 EIA Reference Fuel Price Forecasts (Nominal Dollars)

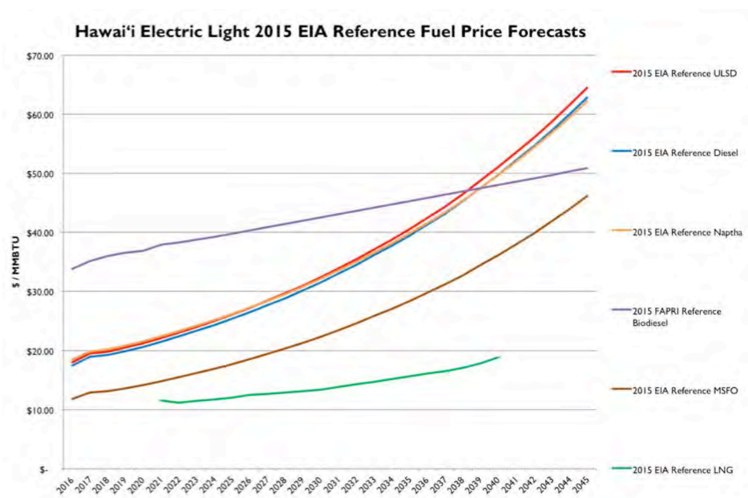

Figure A-25. Hawai‘i Electric Light 2015 EIA Reference Fuel Price Forecasts

Hawai‘i Electric Light February 2016 Forward/Hybrid Curve Fuel Price Forecasts (Nominal Dollars)

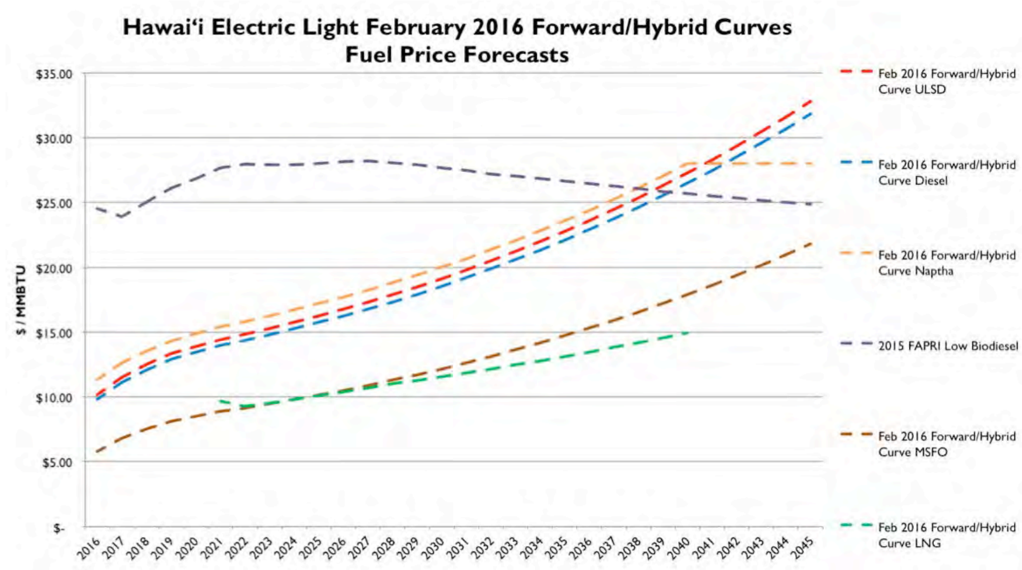

Figure A-26. Hawai‘i Electric Light February 2016 Forward/Hybrid Curve Fuel Price Forecasts

LNG Total Price Forecasts

Chicago Mercantile Exchange Henry Hub Natural Gas Futures (Escalated)

Nominal $/MMBtu	Chicago Mercantile Exchange Henry Hub Natural Gas Futures (Escalated)		
Year	*O'ahu Total Cost*	*Maui Total Cost*	*Hawai'i Island Total Cost*
2021	$13.30	$15.67	$15.89
2022	$12.91	$15.32	$15.55
2023	$13.18	$15.63	$15.86
2024	$13.46	$15.95	$16.18
2025	$13.74	$16.27	$16.51
2026	$14.04	$16.61	$16.86
2027	$14.34	$16.96	$17.21
2028	$14.68	$17.35	$17.60
2029	$14.95	$17.66	$17.92
2030	$15.24	$17.99	$18.26
2031	$15.53	$18.33	$18.60
2032	$15.83	$18.69	$18.96
2033	$16.15	$19.05	$19.33
2034	$16.47	$19.43	$19.71
2035	$16.81	$19.81	$20.11
2036	$17.16	$20.21	$20.51
2037	$17.52	$20.63	$20.93
2038	$17.89	$21.05	$21.36
2039	$18.28	$21.50	$21.81
2040	$18.68	$21.96	$22.28

Table A-25. Chicago Mercantile Exchange Henry Hub Natural Gas Futures (Escalated)

2015 EIA Average Henry Hub Spot Prices for Natural Gas (Reference Case)

$/MMBtu	2015 EIA Average Henry Hub Spot Prices for Natural Gas (Reference Case)		
Year	*O'ahu Total Cost*	*Maui Total Cost*	*Hawai'i Island Total Cost*
2021	$15.20	$17.55	$17.77
2022	$14.79	$17.19	$17.42
2023	$15.13	$17.57	$17.80
2024	$15.42	$17.90	$18.13
2025	$15.72	$18.24	$18.49
2026	$16.14	$18.71	$18.95
2027	$16.35	$18.96	$19.21
2028	$16.56	$19.22	$19.47
2029	$16.83	$19.53	$19.79
2030	$17.03	$19.77	$20.04
2031	$17.52	$20.31	$20.58
2032	$17.98	$20.82	$21.09
2033	$18.44	$21.33	$21.61
2034	$18.92	$21.86	$22.15
2035	$19.38	$22.37	$22.66
2036	$19.85	$22.90	$23.19
2037	$20.25	$23.35	$23.65
2038	$20.79	$23.94	$24.25
2039	$21.60	$24.80	$25.12
2040	$22.59	$25.85	$26.17

Table A-26. 2015 EIA Average Henry Hub Spot Prices for Natural Gas (Reference Case-Nominal $)

SALES FORECASTS

O'ahu Customer Level Sales Forecast

GWh	Underlying Forecast	Energy Efficiency	Distributed Generation (PV)	Electric Vehicles	Customer Level Sales Forecast
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	8,286.0	(1,076.9)	(721.0)	31.2	6,519.3
2017	8,481.3	(1,149.0)	(883.9)	41.9	6,490.3
2018	8,691.4	(1,223.6)	(922.7)	54.5	6,599.6
2019	8,816.8	(1,287.8)	(952.6)	69.2	6,645.6
2020	8,885.6	(1,375.1)	(980.7)	86.4	6,616.2
2021	8,933.4	(1,465.8)	(999.1)	106.2	6,574.7
2022	8,952.7	(1,556.6)	(1,017.7)	128.6	6,507.0
2023	8,987.0	(1,647.4)	(1,034.2)	152.9	6,458.3
2024	9,053.7	(1,744.1)	(1,051.0)	179.0	6,437.6
2025	9,087.4	(1,846.0)	(1,068.0)	206.8	6,380.2
2026	9,154.0	(1,957.0)	(1,085.9)	236.2	6,347.3
2027	9,229.7	(2,079.5)	(1,103.9)	267.2	6,313.5
2028	9,329.1	(2,209.1)	(1,122.5)	300.0	6,297.5
2029	9,376.6	(2,345.6)	(1,141.6)	334.3	6,223.7
2030	9,459.9	(2,486.0)	(1,161.3)	370.3	6,182.9
2031	9,513.1	(2,552.8)	(1,182.2)	407.0	6,185.1
2032	9,581.3	(2,561.4)	(1,204.3)	444.2	6,259.8
2033	9,604.9	(2,567.8)	(1,226.9)	482.1	6,292.3
2034	9,651.7	(2,573.6)	(1,250.8)	520.5	6,347.8
2035	9,703.5	(2,584.1)	(1,275.7)	559.5	6,403.2
2036	9,785.3	(2,600.8)	(1,301.7)	598.9	6,481.7
2037	9,823.4	(2,615.4)	(1,328.6)	638.9	6,518.3
2038	9,885.8	(2,628.1)	(1,356.3)	678.8	6,580.2
2039	9,947.4	(2,644.4)	(1,384.6)	718.7	6,637.1
2040	10,031.6	(2,664.9)	(1,413.7)	758.5	6,711.5
2041	10,065.8	(2,680.1)	(1,443.3)	799.2	6,741.6
2042	10,122.3	(2,691.8)	(1,473.1)	840.9	6,798.3
2043	10,178.0	(2,707.1)	(1,503.3)	883.4	6,851.0
2044	10,256.7	(2,726.4)	(1,534.3)	926.8	6,922.8
2045	10,287.7	(2,741.4)	(1,564.8)	971.1	6,952.6

Table A-27. O'ahu Customer Level Sales Forecast (GWh)

Maui Island Customer Level Sales Forecast

GWh	Underlying Forecast	Energy Efficiency	Distributed Generation (PV)	Electric Vehicles	Customer Level Sales Forecast
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	1,351	(142)	(156)	2	1,055
2017	1,392	(152)	(185)	3	1,059
2018	1,426	(163)	(190)	5	1,078
2019	1,450	(173)	(194)	7	1,091
2020	1,468	(183)	(197)	9	1,096
2021	1,483	(194)	(199)	12	1,103
2022	1,499	(204)	(200)	14	1,110
2023	1,518	(214)	(201)	17	1,120
2024	1,541	(229)	(202)	21	1,131
2025	1,568	(247)	(203)	24	1,142
2026	1,599	(270)	(204)	28	1,151
2027	1,626	(301)	(206)	32	1,152
2028	1,649	(334)	(207)	35	1,143
2029	1,668	(371)	(208)	39	1,128
2030	1,684	(401)	(210)	43	1,116
2031	1,698	(424)	(212)	47	1,109
2032	1,717	(437)	(214)	51	1,117
2033	1,743	(442)	(216)	55	1,141
2034	1,775	(450)	(218)	59	1,166
2035	1,805	(458)	(220)	63	1,190
2036	1,835	(467)	(223)	67	1,213
2037	1,865	(476)	(225)	72	1,236
2038	1,893	(484)	(228)	76	1,257
2039	1,920	(492)	(231)	80	1,277
2040	1,948	(500)	(234)	85	1,298
2041	1,974	(508)	(238)	89	1,317
2042	2,000	(516)	(241)	94	1,336
2043	2,026	(524)	(245)	98	1,355
2044	2,053	(532)	(249)	103	1,375
2045	2,080	(540)	(252)	108	1,395

Table A-28. Maui Island Customer Level Sales Forecast (GWh)

Lana'i Customer Level Sales Forecast

MWh	Underlying Forecast	Energy Efficiency	Distributed Generation (PV)	Electric Vehicles	Customer Level Sales Forecast
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	28,114	(585)	(921)	–	26,608
2017	28,596	(602)	(1,069)	–	26,925
2018	30,273	(618)	(1,140)	–	28,515
2019	30,701	(635)	(1,236)	–	28,830
2020	30,910	(652)	(1,331)	–	28,926
2021	30,472	(668)	(1,427)	–	28,376
2022	30,811	(685)	(1,523)	–	28,603
2023	31,158	(702)	(1,619)	–	28,837
2024	31,510	(719)	(1,715)	–	29,077
2025	31,846	(735)	(1,811)	–	29,300
2026	32,169	(752)	(1,907)	–	29,510
2027	32,493	(769)	(2,003)	–	29,722
2028	32,801	(785)	(2,085)	–	29,932
2029	33,122	(802)	(2,142)	–	30,178
2030	33,449	(819)	(2,182)	–	30,449
2031	33,771	(835)	(2,210)	–	30,725
2032	34,102	(852)	(2,230)	–	31,020
2033	34,438	(869)	(2,244)	–	31,325
2034	34,753	(885)	(2,254)	–	31,614
2035	35,076	(902)	(2,258)	–	31,916
2036	35,409	(919)	(2,258)	–	32,233
2037	35,731	(935)	(2,258)	–	32,538
2038	36,062	(952)	(2,258)	–	32,853
2039	36,539	(969)	(2,258)	–	33,313
2040	36,949	(985)	(2,258)	–	33,706
2041	37,319	(1,002)	(2,258)	–	34,059
2042	37,676	(1,019)	(2,258)	–	34,400
2043	38,008	(1,035)	(2,258)	–	34,715
2044	38,348	(1,052)	(2,258)	–	35,039
2045	38,690	(1,069)	(2,258)	–	35,364

Table A-29. Lana'i Customer Level Sales Forecast (MWh)

Moloka'i Customer Level Sales Forecast

MWh	Underlying Forecast	Energy Efficiency	Distributed Generation (PV)	Electric Vehicles	Customer Level Sales Forecast
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	32,779	(1,829)	(3,754)	–	27,196
2017	32,810	(1,896)	(4,147)	–	26,768
2018	32,837	(1,963)	(4,234)	–	26,641
2019	32,864	(2,030)	(4,348)	–	26,486
2020	32,891	(2,097)	(4,481)	–	26,312
2021	32,918	(2,164)	(4,654)	–	26,100
2022	32,945	(2,231)	(4,739)	–	25,975
2023	32,972	(2,298)	(4,830)	–	25,844
2024	32,999	(2,365)	(4,951)	–	25,683
2025	33,027	(2,433)	(5,076)	–	25,518
2026	33,052	(2,500)	(5,205)	–	25,348
2027	33,078	(2,567)	(5,329)	–	25,183
2028	33,104	(2,634)	(5,452)	–	25,019
2029	33,130	(2,701)	(5,581)	–	24,849
2030	33,156	(2,768)	(5,715)	–	24,673
2031	33,182	(2,835)	(5,854)	–	24,493
2032	33,208	(2,902)	(5,996)	–	24,310
2033	33,235	(2,969)	(6,110)	–	24,156
2034	33,261	(3,036)	(6,193)	–	24,032
2035	33,287	(3,103)	(6,263)	–	23,921
2036	33,313	(3,170)	(6,321)	–	23,822
2037	33,340	(3,237)	(6,351)	–	23,751
2038	33,366	(3,305)	(6,363)	–	23,699
2039	33,393	(3,372)	(6,371)	–	23,650
2040	33,419	(3,439)	(6,375)	–	23,605
2041	33,446	(3,506)	(6,375)	–	23,564
2042	33,472	(3,573)	(6,375)	–	23,524
2043	33,499	(3,640)	(6,375)	–	23,483
2044	33,525	(3,707)	(6,375)	–	23,443
2045	33,552	(3,774)	(6,375)	–	23,403

Table A-30. Moloka'i Customer Level Sales Forecast (MWh)

Hawai'i Island Customer Level Sales Forecast

GWh	Underlying Forecast	Energy Efficiency	Distributed Generation (PV)	Electric Vehicles	Customer Level Sales Forecast
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	1,256.9	(116.5)	(129.8)	0.5	1,011.2
2017	1,263.5	(128.1)	(150.7)	0.7	985.4
2018	1,286.5	(139.7)	(156.8)	0.8	990.9
2019	1,310.0	(151.3)	(161.4)	1.0	998.3
2020	1,335.0	(162.8)	(166.0)	1.1	1,007.3
2021	1,351.5	(174.4)	(170.0)	1.2	1,008.2
2022	1,368.0	(186.0)	(173.0)	1.3	1,010.3
2023	1,383.8	(197.6)	(175.3)	1.4	1,012.3
2024	1,402.8	(212.4)	(177.8)	1.6	1,014.2
2025	1,417.7	(229.8)	(180.3)	1.7	1,009.3
2026	1,437.8	(251.9)	(182.8)	1.9	1,005.0
2027	1,459.6	(279.3)	(185.6)	2.0	996.7
2028	1,484.2	(309.7)	(188.4)	2.2	988.2
2029	1,502.8	(343.4)	(191.2)	2.3	970.5
2030	1,523.0	(367.8)	(194.2)	2.5	963.4
2031	1,541.6	(383.5)	(197.2)	2.6	963.6
2032	1,562.2	(399.8)	(200.3)	2.8	964.9
2033	1,577.7	(409.7)	(203.3)	2.9	967.6
2034	1,596.5	(414.2)	(206.6)	3.1	978.7
2035	1,616.4	(419.3)	(210.0)	3.2	990.4
2036	1,640.3	(424.9)	(213.4)	3.4	1,005.3
2037	1,659.2	(431.0)	(217.2)	3.6	1,014.6
2038	1,681.4	(437.3)	(221.2)	3.7	1,026.6
2039	1,703.9	(443.8)	(225.7)	3.9	1,038.3
2040	1,729.7	(450.4)	(230.6)	4.1	1,052.7
2041	1,749.7	(457.1)	(236.0)	4.3	1,060.8
2042	1,772.9	(463.9)	(242.0)	4.4	1,071.5
2043	1,796.2	(470.7)	(248.4)	4.6	1,081.7
2044	1,822.8	(477.6)	(255.3)	4.8	1,094.8
2045	1,843.8	(484.6)	(262.8)	5.0	1,101.4

Table A-31. Hawai'i Island Customer Level Sales Forecast (GWh)

PEAK DEMAND FORECASTS

O'ahu Generation Level Peak Demand Forecast

MW	Underlying Forecast	Energy Efficiency	Distributed Generation (PV)	Electric Vehicles	Net Peak Forecast*
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	1,363.7	(198.70)	0	0	1,165.0
2017	1,397.7	(215.70)	0	0	1,182.0
2018	1,431.7	(232.70)	0	0	1,199.0
2019	1,447.7	(248.70)	0	0	1,199.0
2020	1,454.7	(266.70)	0	0	1,188.0
2021	1,465.7	(284.70)	0	0	1,181.0
2022	1,468.7	(302.70)	0	0	1,166.0
2023	1,473.7	(321.70)	0	0	1,152.0
2024	1,479.7	(344.70)	0	0	1,135.0
2025	1,488.7	(369.70)	0	0	1,119.0
2026	1,499.7	(400.70)	0	0	1,099.0
2027	1,511.7	(436.70)	0	0	1,075.0
2028	1,524.7	(474.70)	0	0	1,050.0
2029	1,534.7	(516.70)	0	0	1,018.0
2030	1,547.7	(560.70)	0	0	987.0
2031	1,555.7	(568.70)	0	0	987.0
2032	1,563.7	(570.70)	0	0	993.0
2033	1,570.7	(571.70)	0	0	999.0
2034	1,578.7	(573.70)	0	0	1,005.0
2035	1,586.7	(576.70)	0	0	1,010.0
2036	1,595.7	(581.70)	0	0	1,014.0
2037	1,605.7	(583.70)	0	0	1,022.0
2038	1,615.7	(587.70)	0	0	1,028.0
2039	1,625.7	(591.70)	0	0	1,034.0
2040	1,634.7	(596.70)	0	0	1,038.0
2041	1,643.7	(599.70)	0	0	1,044.0
2042	1,651.7	(602.70)	0	0	1,049.0
2043	1,660.7	(606.70)	0	0	1,054.0
2044	1,670.7	(611.70)	0	0	1,059.0
2045	1,679.7	(614.70)	0	0	1,065.0

* System Peak occurs in the evening.

Table A-32. O'ahu Generation Level Peak Demand Forecast (MW)

Maui Island Generation Level Peak Demand Forecast

MW	Underlying Forecast	Energy Efficiency	Distributed Generation (PV)	Electric Vehicles	Net Peak Forecast*
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	226.7	(25.6)	0	0.2	201.3
2017	234.0	(27.5)	0	0.3	206.8
2018	239.4	(29.3)	0	0.4	210.5
2019	243.4	(31.3)	0	0.6	212.7
2020	245.7	(33.2)	0	0.8	213.3
2021	248.9	(35.0)	0	1.0	214.9
2022	251.5	(37.0)	0	1.3	215.8
2023	254.7	(38.8)	0	0.8	216.7
2024	257.8	(42.1)	0	0.9	216.7
2025	263.0	(45.4)	0	1.1	218.7
2026	268.1	(50.6)	0	1.2	218.7
2027	273.0	(56.2)	0	1.4	218.2
2028	276.7	(62.6)	0	1.6	215.6
2029	281.2	(69.8)	0	1.7	213.2
2030	282.2	(73.9)	0	1.9	210.2
2031	284.5	(78.1)	0	2.1	208.6
2032	286.9	(78.8)	0	2.3	210.4
2033	291.9	(79.9)	0	2.5	214.5
2034	297.1	(81.5)	0	2.6	218.2
2035	302.1	(83.1)	0	2.8	221.9
2036	306.3	(84.6)	0	3.0	224.7
2037	312.1	(86.3)	0	3.2	229.0
2038	316.8	(87.8)	0	3.4	232.5
2039	321.4	(89.2)	0	3.6	235.8
2040	325.2	(90.7)	0	3.8	238.3
2041	330.3	(92.2)	0	4.0	242.2
2042	334.7	(93.5)	0	4.2	245.3
2043	339.0	(95.0)	0	4.4	248.4
2044	342.8	(96.5)	0	4.6	250.9
2045	348.2	(97.9)	0	4.8	255.1

* System Peak occurs in the evening.

Table A-33. Maui Island Generation Level Peak Demand Forecast (MW)

Lana‘i Generation Level Peak Demand Forecast

MW	Underlying Forecast	Energy Efficiency	Distributed Generation (PV)	Electric Vehicles	Gross Peak Forecast*
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	5.4	(0.1)	0	0	5.3
2017	5.5	(0.2)	0	0	5.3
2018	5.8	(0.1)	0	0	5.7
2019	5.9	(0.2)	0	0	5.7
2020	5.9	(0.1)	0	0	5.8
2021	5.9	(0.1)	0	0	5.8
2022	6.0	(0.1)	0	0	5.9
2023	6.1	(0.2)	0	0	5.9
2024	6.1	(0.1)	0	0	6.0
2025	6.2	(0.1)	0	0	6.1
2026	6.3	(0.2)	0	0	6.1
2027	6.3	(0.1)	0	0	6.2
2028	6.4	(0.2)	0	0	6.2
2029	6.4	(0.1)	0	0	6.3
2030	6.5	(0.2)	0	0	6.3
2031	6.6	(0.2)	0	0	6.4
2032	6.6	(0.1)	0	0	6.5
2033	6.7	(0.2)	0	0	6.5
2034	6.7	(0.1)	0	0	6.6
2035	6.8	(0.2)	0	0	6.6
2036	6.9	(0.2)	0	0	6.7
2037	6.9	(0.1)	0	0	6.8
2038	7.0	(0.2)	0	0	6.8
2039	7.1	(0.2)	0	0	6.9
2040	7.2	(0.2)	0	0	7.0
2041	7.2	(0.2)	0	0	7.0
2042	7.3	(0.2)	0	0	7.1
2043	7.4	(0.2)	0	0	7.2
2044	7.4	(0.2)	0	0	7.2
2045	7.5	(0.2)	0	0	7.3

* System Peak occurs in the evening.

Table A-34. Lana‘i Generation Level Peak Demand Forecast (MW)

Moloka'i Generation Level Peak Demand Forecast

MW	Underlying Forecast	Energy Efficiency	Distributed Generation (PV)	Electric Vehicles	Gross Peak Forecast*
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	5.8	(0.3)	0	0	5.5
2017	5.9	(0.4)	0	0	5.5
2018	5.9	(0.4)	0	0	5.5
2019	5.9	(0.4)	0	0	5.5
2020	5.9	(0.4)	0	0	5.5
2021	5.9	(0.4)	0	0	5.5
2022	5.9	(0.4)	0	0	5.5
2023	5.9	(0.4)	0	0	5.5
2024	5.9	(0.4)	0	0	5.5
2025	5.9	(0.4)	0	0	5.5
2026	5.9	(0.4)	0	0	5.5
2027	5.9	(0.5)	0	0	5.4
2028	5.9	(0.5)	0	0	5.4
2029	5.9	(0.5)	0	0	5.4
2030	5.9	(0.5)	0	0	5.4
2031	5.9	(0.5)	0	0	5.4
2032	5.9	(0.5)	0	0	5.4
2033	5.9	(0.5)	0	0	5.4
2034	5.9	(0.5)	0	0	5.4
2035	5.9	(0.5)	0	0	5.4
2036	5.9	(0.5)	0	0	5.4
2037	6.0	(0.6)	0	0	5.4
2038	6.0	(0.6)	0	0	5.4
2039	6.0	(0.6)	0	0	5.4
2040	6.0	(0.7)	0	0	5.3
2041	6.0	(0.7)	0	0	5.3
2042	6.0	(0.7)	0	0	5.3
2043	6.0	(0.7)	0	0	5.3
2044	6.0	(0.7)	0	0	5.3
2045	6.0	(0.7)	0	0	5.3

* System Peak occurs in the evening.

Table A-35. Moloka'i Generation Level Peak Demand Forecast (MW)

Hawai‘i Island Generation Level Peak Demand Forecast

MW	Underlying Forecast	Energy Efficiency	Distributed Generation (PV)	Electric Vehicles	Net Peak Forecast*
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	208.2	(21.4)	0	0	186.8
2017	211.6	(23.7)	0	0	187.9
2018	215.4	(26.0)	0	0	189.4
2019	219.5	(28.3)	0	0	191.2
2020	223.2	(30.6)	0	0	192.6
2021	226.7	(32.9)	0	0	193.8
2022	229.6	(35.2)	0	0	194.4
2023	232.4	(37.5)	0	0	194.9
2024	235.0	(41.0)	0	0	194.0
2025	238.3	(44.5)	0	0	193.8
2026	241.8	(49.6)	0	0	192.2
2027	245.6	(55.3)	0	0	190.3
2028	249.2	(61.6)	0	0	187.6
2029	253.1	(68.6)	0	0	184.5
2030	256.6	(71.6)	0	0	185.0
2031	259.9	(74.7)	0	0	185.2
2032	262.8	(78.0)	0	0	184.8
2033	266.3	(78.9)	0	0	187.4
2034	269.6	(79.8)	0	0	189.8
2035	273.1	(80.9)	0	0	192.2
2036	276.5	(82.1)	0	0	194.4
2037	280.7	(83.3)	0	0	197.4
2038	284.6	(84.6)	0	0	200.0
2039	288.6	(85.9)	0	0	202.7
2040	292.3	(87.2)	0	0	205.1
2041	296.7	(88.5)	0	0	208.2
2042	300.8	(89.8)	0	0	211.0
2043	305.0	(91.2)	0	0	213.8
2044	308.9	(92.6)	0	0	216.3
2045	313.4	(94.0)	0	0	219.4

* System Peak occurs in the evening.

Table A-36. Hawai‘i Island Generation Level Peak Demand Forecast (MW)

SALES FORECAST COMPARISONS

O'ahu Interim 2016 PSIP versus 2014 PSIP Sales Forecast Comparisons

GWh	Underlying Forecast Differential	Energy Efficiency Differential	Distributed Generation (PV) Differential	Electric Vehicles Differential	Customer Level Sales Forecast Differential
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	(208.5)	(27.2)	(176.6)	16.4	(395.9)
2017	(208.1)	(18.6)	(290.9)	19.0	(498.6)
2018	(109.8)	(12.5)	(297.9)	22.1	(398.1)
2019	(79.4)	4.0	(296.7)	25.7	(346.4)
2020	(97.1)	(2.6)	(290.0)	30.0	(359.7)
2021	(109.9)	(2.1)	(282.5)	35.1	(359.4)
2022	(162.6)	15.6	(272.2)	40.9	(378.3)
2023	(200.8)	50.1	(259.4)	47.0	(363.1)
2024	(204.1)	98.2	(244.3)	53.0	(297.2)
2025	(190.9)	163.5	(234.6)	59.0	(203.0)
2026	(102.3)	245.7	(223.9)	64.9	(15.6)
2027	(29.9)	346.3	(214.0)	70.5	172.9
2028	33.4	474.4	(202.9)	76.1	381.0
2029	6.8	635.6	(198.4)	81.3	525.3
2030	(28.5)	839.0	(193.0)	86.5	704.0

Table A-37. O'ahu Interim 2016 PSIP versus 2014 PSIP Sales Forecast Comparisons (GWh)

Maui Island Interim 2016 PSIP versus 2014 PSIP Sales Forecast Comparisons

GWh	Underlying Forecast Differential	Energy Efficiency Differential	Distributed Generation (PV) Differential	Electric Vehicles Differential	Customer Level Sales Forecast Differential*
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	31.3	4.9	(18.2)	1.2	19.1
2017	31.6	6.8	(41.2)	2.0	(0.8)
2018	16.9	8.7	(39.0)	2.8	(10.6)
2019	6.8	10.6	(35.8)	3.8	(14.6)
2020	(3.8)	12.4	(32.6)	4.7	(19.2)
2021	(4.2)	14.3	(29.4)	5.7	(13.6)
2022	(4.7)	16.8	(26.3)	6.7	(7.5)
2023	(2.5)	20.9	(23.4)	7.6	2.6
2024	(0.9)	22.8	(20.8)	8.6	9.7
2025	13.4	23.5	(18.4)	9.7	28.2
2026	30.2	21.2	(16.1)	10.4	45.7
2027	45.3	15.3	(14.1)	11.4	57.9
2028	53.8	9.3	(12.3)	11.9	62.7
2029	63.1	3.5	(10.7)	12.3	68.2
2030	66.8	8.8	(9.4)	12.5	78.6

* Includes off-grid and leap year impacts.

Table A-38. Maui Island Interim 2016 PSIP versus 2014 PSIP Sales Forecast Comparisons (GWh)

Lana'i Interim 2016 PSIP versus 2014 PSIP Sales Forecast Comparisons

MWh	Underlying Forecast Differential	Energy Efficiency Differential	Distributed Generation (PV) Differential	Electric Vehicles Differential	Customer Level Sales Forecast Differential*
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	(264.2)	(46.9)	432.7	–	121.7
2017	(171.6)	(46.9)	461.5	–	243.0
2018	1,077.1	(46.9)	522.8	–	1,553.1
2019	1,163.6	(46.9)	526.2	–	1,642.9
2020	1,066.8	(46.9)	529.5	–	1,549.4
2021	349.7	(46.9)	532.9	–	835.7
2022	434.2	(46.9)	536.3	–	923.6
2023	535.2	(46.9)	472.4	–	960.6
2024	641.7	(46.9)	380.4	–	975.3
2025	739.1	(46.9)	284.6	–	976.8
2026	865.2	(46.9)	203.2	–	1,021.5
2027	1,013.4	(46.9)	125.2	–	1,091.8
2028	1,168.3	(46.9)	101.7	–	1,223.1
2029	1,336.5	(46.9)	111.8	–	1,401.4
2030	1,509.1	(46.9)	71.6	–	1,533.8

* Includes off-grid and leap year impacts.

Table A-39. Lana'i Interim 2016 PSIP versus 2014 PSIP Sales Forecast Comparisons (MWh)

Moloka'i Interim 2016 PSIP versus 2014 PSIP Sales Forecast Comparisons

MWh	Underlying Forecast Differential	Energy Efficiency Differential	Distributed Generation (PV) Differential	Electric Vehicles Differential	Customer Level Sales Forecast Differential*
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	(203.9)	(61.8)	(128.6)	–	(394.3)
2017	(367.8)	(61.8)	(291.3)	–	(720.9)
2018	(439.0)	(61.8)	(285.4)	–	(786.2)
2019	(498.0)	(61.8)	11.4	–	(548.4)
2020	(540.8)	(61.8)	158.4	–	(444.2)
2021	(535.9)	(61.8)	113.8	–	(483.9)
2022	(528.7)	(61.8)	62.3	–	(528.2)
2023	(521.9)	(61.8)	1.0	–	(582.7)
2024	(492.8)	(61.8)	(95.5)	–	(650.1)
2025	(481.4)	(61.8)	(196.7)	–	(739.8)
2026	(488.9)	(61.8)	(301.9)	–	(852.6)
2027	(467.0)	(61.8)	(401.4)	–	(930.2)
2028	(457.7)	(61.8)	(500.2)	–	(1,019.7)
2029	(459.7)	(61.8)	(605.3)	–	(1,126.8)
2030	(442.3)	(61.8)	(722.9)	–	(1,227.0)

* Includes off-grid and leap year impacts.

Table A-40. Moloka'i Interim 2016 PSIP versus 2014 PSIP Sales Forecast Comparisons (MWh)

Hawai'i Island Interim 2016 PSIP versus 2014 PSIP Sales Forecast

GWh	Underlying Forecast Differential	Energy Efficiency Differential	Distributed Generation (PV) Differential	Electric Vehicles Differential	Customer Level Sales Forecast Differential
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	(35.3)	5.9	(24.9)	0.1	(54.2)
2017	(51.7)	7.6	(34.2)	0.2	(78.1)
2018	(56.9)	9.2	(35.7)	0.3	(83.2)
2019	(58.0)	10.9	(36.2)	0.4	(83.0)
2020	(57.0)	12.5	(36.3)	0.4	(80.4)
2021	(57.7)	12.7	(37.3)	0.4	(81.9)
2022	(59.5)	12.4	(37.0)	0.4	(83.7)
2023	(61.5)	13.3	(36.1)	0.5	(83.8)
2024	(65.5)	12.5	(35.0)	0.5	(87.5)
2025	(67.0)	10.6	(34.9)	0.6	(90.6)
2026	(65.8)	5.9	(34.4)	0.6	(93.6)
2027	(63.3)	(2.2)	(34.4)	0.7	(99.1)
2028	(58.5)	(11.1)	(34.0)	0.7	(102.8)
2029	(52.5)	(20.8)	(34.6)	0.8	(107.2)
2030	(49.0)	(18.5)	(35.1)	0.8	(101.8)

Table A-41. Hawai'i Island Interim 2016 PSIP versus 2014 PSIP Sales Forecast Comparisons (GWh)

UHERO STATE OF HAWAI'I FORECASTS

State of Hawai'i 2014 and 2015 Non-Agricultural Job Forecasts

Year	2015 Outlook	2014 Outlook	% Difference (15/14)
2013	618,600	617,600	0.2%
2014	625,300	626,200	–0.1%
2015	634,500	636,900	–0.4%
2016	642,800	647,100	–0.7%
2017	649,500	655,700	–0.9%
2018	654,100	661,400	–1.1%
2019	657,200	664,100	–1.0%
2020	658,900	665,600	–1.0%
2021	660,100	668,400	–1.2%
2022	661,100	672,500	–1.7%
2023	663,000	677,100	–2.1%
2024	666,200	682,200	–2.3%
2025	671,500	687,300	–2.3%
2026	678,200	692,000	–2.0%
2027	685,000	696,400	–1.6%
2028	691,000	700,800	–1.4%
2029	695,600	705,200	–1.4%
2030	698,600	709,700	–1.6%

Table A-42. State of Hawai'i 2014 and 2015 Non-Agricultural Job Forecasts

State of Hawai'i 2014 and 2015 Real Personal Income per Capita Forecasts

Year	2015 Outlook	2014 Outlook	% Difference (15/14)
2013	17.8	18.0	–1.0%
2014	18.1	18.2	–0.9%
2015	18.4	18.7	–1.7%
2016	18.7	19.0	–1.7%
2017	18.9	19.2	–1.6%
2018	19.1	19.3	–1.3%
2019	19.2	19.3	–0.9%
2020	19.3	19.4	–0.6%
2021	19.3	19.4	–0.5%
2022	19.4	19.5	–0.6%
2023	19.5	19.6	–0.6%
2024	19.6	19.7	–0.5%
2025	19.8	19.8	–0.1%
2026	20.0	19.9	0.3%
2027	20.2	20.0	0.8%
2028	20.3	20.1	1.0%
2029	20.4	20.2	1.1%
2030	20.5	20.3	1.0%

Table A-43. State of Hawai'i 2014 and 2015 Real Personal Income per Capita Forecasts ($000)

State of Hawaiʻi 2014 and 2015 Visitor Arrivals Forecasts

Year	2015 Outlook	2014 Outlook	% Difference (15/14)
2013	8,003.5	8,064.3	–0.8%
2014	8,159.6	8,141.6	0.2%
2015	8,233.5	8,268.7	–0.4%
2016	8,302.4	8,366.9	–0.8%
2017	8,345.6	8,447.7	–1.2%
2018	8,404.6	8,521.5	–1.4%
2019	8,439.8	8,591.6	–1.8%
2020	8,477.4	8,657.7	–2.1%
2021	8,524.9	8,720.6	–2.2%
2022	8,578.1	8,778.8	–2.3%
2023	8,636.4	8,832.1	–2.2%
2024	8,696.6	8,880.3	–2.1%
2025	8,758.0	8,923.4	–1.9%
2026	8,817.5	8,962.3	–1.6%
2027	8,866.8	8,998.3	–1.5%
2028	8,906.7	9,033.6	–1.4%
2029	8,936.5	9,069.1	–1.5%
2030	8,960.9	9,108.3	–1.6%

Table A-44. State of Hawaiʻi 2014 and 2015 Visitor Arrivals Forecasts

RESOURCE CAPITAL COSTS

New Resource Cost Assumptions: O‘ahu

Hawai‘i specific nominal (as-spent) overnight capital cost $/kW$_{AC}$,[23] without Allowance for Funds Used During Construction (AFUDC).

Nominal $/kW	Replacement Resource Capital Cost Assumptions: O‘ahu						
Technology	Onshore Wind	Offshore Wind Floating Platform	Onshore Wind + Cable	Onshore Wind + Cable	Utility-Scale Solar PV	Solar DG-PV	CSP w/ 10 hours storage
Size (MW)	30	400	200	400	20	< 10 kW	100
Fuel	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*
2016	$2,465†	$5,062†	N/A	N/A	$2,793†	$3,945	$12,304†
2017	$2,504†	$4,849†	N/A	N/A	$2,627†	$3,716	$12,525†
2018	$2,443	$4,626†	N/A	N/A	$2,547	$3,573	$11,681
2019	$2,428	$4,565†	N/A	N/A	$2,484	$3,457	$10,781
2020	$2,480	$4,500	$5,097	$4,572	$2,432	$3,360	$9,848
2021	$2,520	$4,431	$5,207	$4,672	$2,392	$3,285	$8,874
2022	$2,586	$4,358	$5,324	$4,778	$2,357	$3,218	$7,867
2023	$2,644	$4,249	$5,456	$4,899	$2,328	$3,160	$7,813
2024	$2,691	$4,134	$5,560	$4,992	$2,304	$3,111	$7,756
2025	$2,722	$4,013	$5,664	$5,085	$2,284	$3,068	$7,694
2026	$2,753	$4,026	$5,758	$5,166	$2,270	$3,034	$7,627
2027	$2,773	$4,037	$5,851	$5,248	$2,257	$3,004	$7,555
2028	$2,805	$4,048	$5,948	$5,333	$2,247	$2,976	$7,478
2029	$2,830	$4,058	$6,049	$5,422	$2,238	$2,952	$7,396
2030	$2,867	$4,067	$6,154	$5,514	$2,232	$2,933	$7,309

† = Resource is not available this year.

Table A-45. Replacement Resource Capital Cost Assumptions w/o AFUDC: O‘ahu 2016–2030 (1 of 4)

[23] Solar PV costs are typically quoted based on the price per kW of Direct Current (DC) output (that is, the total capacity of the PV panels). These utility-scale solar PV costs has been converted to the price per kW of Alternating Current (AC) output supplied to the grid using a DC to AC ratio of 1.5:1 for this conversion.

Nominal $/kW	Replacement Resource Capital Cost Assumptions: O‘ahu						
Technology	Onshore Wind	Offshore Wind Floating Platform	Onshore Wind + Cable	Onshore Wind + Cable	Utility-Scale Solar PV	Solar DG-PV	CSP w/ 10 hours storage
Size (MW)	30	400	200	400	20	< 10 kW	100
Fuel	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2031	$2,891	$4,076	$6,257	$5,604	$2,226	$2,925	$7,216
2032	$2,925	$4,083	$6,362	$5,696	$2,221	$2,917	$7,117
2033	$2,949	$4,122	$6,468	$5,789	$2,215	$2,910	$7,245
2034	$2,984	$4,162	$6,577	$5,884	$2,209	$2,902	$7,375
2035	$3,010	$4,202	$6,688	$5,981	$2,203	$2,894	$7,508
2036	$3,045	$4,242	$6,800	$6,079	$2,197	$2,887	$7,643
2037	$3,071	$4,282	$6,915	$6,179	$2,192	$2,879	$7,781
2038	$3,107	$4,322	$7,031	$6,281	$2,186	$2,872	$7,921
2039	$3,134	$4,363	$7,150	$6,385	$2,180	$2,864	$8,064
2040	$3,171	$4,403	$7,270	$6,490	$2,174	$2,856	$8,209
2041	$3,199	$4,443	$7,393	$6,598	$2,169	$2,849	$8,356
2042	$3,237	$4,484	$7,518	$6,707	$2,163	$2,841	$8,507
2043	$3,265	$4,528	$7,646	$6,818	$2,157	$2,834	$8,660
2044	$3,303	$4,573	$7,775	$6,931	$2,151	$2,827	$8,816
2045	$3,333	$4,617	$7,907	$7,046	$2,146	$2,819	$8,975

Table A-46. Replacement Resource Capital Cost Assumptions w/o AFUDC: O‘ahu 2031–2045 (2 of 4)

Nominal $/kW	Replacement Resource Capital Cost Assumptions: O'ahu						
Technology	Combined Cycle Gas	Combined Cycle Gas	Simple Cycle Gas	Biomass	Internal Combustion	Internal Combustion	Internal Combustion
Size (MW)	383 (3 x 1)	152 (1 x 1)	100	20	27 (3 x 9 MW)	54 (6 x 9 MW)	100 (6 x 16.8 MW) Power Barge
Fuel	Gas / Oil	Gas / Oil	Gas / Oil	Biomass	Gas / Oil	Gas / Oil	Gas / Oil
2016	$1,758†	$1,660†	$1,237†	$5,251†	$3,177†	$2,493†	$1,323†
2017	$1,783†	$1,683†	$1,253†	$5,081†	$3,219†	$2,526†	$1,347†
2018	$1,797†	$1,697†	$1,261†	$5,153	$3,238†	$2,541†	$1,371
2019	$1,822†	$1,720†	$1,277	$5,228	$3,280	$2,574	$1,396
2020	$1,845†	$1,742†	$1,292	$5,299	$3,319	$2,604	$1,421
2021	$1,870	$1,766	$1,309	$5,376	$3,362	$2,638	$1,447
2022	$1,896	$1,790	$1,326	$5,455	$3,406	$2,672	$1,473
2023	$1,921	$1,813	$1,342	$5,532	$3,448	$2,705	$1,499
2024	$1,944	$1,836	$1,358	$5,608	$3,487	$2,736	$1,526
2025	$1,969	$1,859	$1,373	$5,692	$3,527	$2,768	$1,554
2026	$1,992	$1,881	$1,388	$5,770	$3,564	$2,797	$1,582
2027	$2,021	$1,909	$1,408	$5,853	$3,617	$2,838	$1,610
2028	$2,051	$1,937	$1,428	$5,939	$3,668	$2,878	$1,639
2029	$2,079	$1,963	$1,447	$6,023	$3,716	$2,916	$1,669
2030	$2,108	$1,991	$1,466	$6,107	$3,766	$2,955	$1,699

† = Resource is not available this year.

Table A-47. Replacement Resource Capital Cost Assumptions w/o AFUDC: O'ahu 2016–2030 (3 of 4)

Nominal $/kW	Replacement Resource Capital Cost Assumptions: O‘ahu						
Technology	Combined Cycle Gas	Combined Cycle Gas	Simple Cycle Gas	Biomass	Internal Combustion	Internal Combustion	Internal Combustion
Size (MW)	383 (3 x 1)	152 (1 x 1)	100	20	27 (3 x 9 MW)	54 (6 x 9 MW)	100 (6 x 16.8 MW) Power Barge
Fuel	Gas / Oil	Gas / Oil	Gas / Oil	Biomass	Gas / Oil	Gas / Oil	Gas / Oil
2031	$2,139	$2,019	$1,487	$6,192	$3,819	$2,997	$1,729
2032	$2,169	$2,048	$1,507	$6,278	$3,872	$3,038	$1,761
2033	$2,202	$2,079	$1,530	$6,370	$3,930	$3,083	$1,792
2034	$2,234	$2,110	$1,552	$6,458	$3,986	$3,127	$1,825
2035	$2,270	$2,143	$1,577	$6,546	$4,050	$3,178	$1,857
2036	$2,304	$2,176	$1,601	$6,632	$4,112	$3,226	$1,891
2037	$2,342	$2,211	$1,627	$6,724	$4,179	$3,279	$1,925
2038	$2,379	$2,246	$1,653	$6,810	$4,246	$3,331	$1,959
2039	$2,419	$2,284	$1,681	$6,895	$4,317	$3,387	$1,995
2040	$2,455	$2,318	$1,706	$6,973	$4,382	$3,439	$2,031
2041	$2,499	$2,360	$1,737	$7,098	$4,461	$3,501	$2,067
2042	$2,544	$2,403	$1,768	$7,226	$4,542	$3,564	$2,104
2043	$2,590	$2,446	$1,800	$7,356	$4,623	$3,628	$2,142
2044	$2,637	$2,490	$1,832	$7,489	$4,707	$3,693	$2,181
2045	$2,684	$2,535	$1,865	$7,624	$4,791	$3,760	$2,220

Table A-48. Replacement Resource Capital Cost Assumptions w/o AFUDC: O‘ahu 2031–2045 (4 of 4)

New Resource Cost Assumptions: Maui, Lana'i, Moloka'i, Hawai'i Island

Hawai'i specific nominal (as-spent) overnight capital cost $/kW$_{AC}$ (without AFUDC)

Nominal $/kW	Replacement Resource Capital Cost Assumptions: Maui, Lana'i, Moloka'i, Hawai'i Island						
Technology	Onshore Wind	Onshore Wind	Onshore Wind	Utility-Scale Solar PV*	Utility-Scale Solar PV*	Utility-Scale Solar PV*	Utility-Scale Solar PV*
Size (MW)	10	20	30	1	5	10	20
Fuel	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*
Island	Hawai'i Maui	Hawai'i Maui	Hawai'i Maui	Lana'i Moloka'i	Hawai'i Maui	Hawai'i Maui	Hawai'i Maui
2016	$4,171†	$2,968†	$2,465†	$4,023†	$3,262†	$2,849†	$2,574†
2017	$4,237†	$3,015†	$2,504†	$3,783	$3,068†	$2,680†	$2,421†
2018	$4,134	$2,941	$2,443	$3,669	$2,976	$2,599	$2,348
2019	$4,108	$2,923	$2,428	$3,577	$2,901	$2,534	$2,289
2020	$4,198	$2,987	$2,480	$3,503	$2,841	$2,481	$2,241
2021	$4,266	$3,035	$2,520	$3,446	$2,795	$2,441	$2,205
2022	$4,377	$3,114	$2,586	$3,396	$2,754	$2,405	$2,173
2023	$4,475	$3,184	$2,644	$3,353	$2,720	$2,375	$2,146
2024	$4,553	$3,240	$2,691	$3,319	$2,691	$2,351	$2,123
2025	$4,606	$3,277	$2,722	$3,290	$2,669	$2,331	$2,105
2026	$4,659	$3,315	$2,753	$3,270	$2,652	$2,316	$2,092
2027	$4,693	$3,339	$2,773	$3,251	$2,637	$2,303	$2,080
2028	$4,747	$3,377	$2,805	$3,236	$2,625	$2,292	$2,071
2029	$4,789	$3,407	$2,830	$3,224	$2,615	$2,284	$2,063
2030	$4,237	$3,015	$2,504	$3,783	$3,068	$2,680	$2,421

* Utility-Scale Solar PV might not be applicable with high penetrations of DG-PV.

† = Resource is not available this year.

Table A-49. Replacement Resource Capital Cost Assumptions w/o AFUDC: Maui, Lana'i, Moloka'i, Hawai'i Island 2016–2030 (1 of 4)

Nominal $/kW	Replacement Resource Capital Cost Assumptions: Maui, Lana'i, Moloka'i, Hawai'i Island						
Technology	Onshore Wind	Onshore Wind	Onshore Wind	Utility-Scale Solar PV*	Utility-Scale Solar PV*	Utility-Scale Solar PV*	Utility-Scale Solar PV*
Size (MW)	10	20	30	1	5	10	20
Fuel	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Island	Hawai'i Maui	Hawai'i Maui	Hawai'i Maui	Lana'i Moloka'i	Hawai'i Maui	Hawai'i Maui	Hawai'i Maui
2031	$4,892	$3,481	$2,891	$3,207	$2,601	$2,272	$2,052
2032	$4,950	$3,522	$2,925	$3,199	$2,594	$2,266	$2,047
2033	$4,992	$3,552	$2,949	$3,190	$2,587	$2,260	$2,041
2034	$5,051	$3,594	$2,984	$3,182	$2,580	$2,254	$2,036
2035	$5,093	$3,624	$3,010	$3,173	$2,574	$2,248	$2,031
2036	$5,154	$3,667	$3,045	$3,165	$2,567	$2,242	$2,025
2037	$5,198	$3,698	$3,071	$3,157	$2,560	$2,236	$2,020
2038	$5,259	$3,742	$3,107	$3,148	$2,553	$2,230	$2,015
2039	$5,304	$3,774	$3,134	$3,140	$2,547	$2,224	$2,009
2040	$5,367	$3,819	$3,171	$3,132	$2,540	$2,218	$2,004
2041	$5,414	$3,852	$3,199	$3,124	$2,533	$2,213	$1,999
2042	$5,478	$3,897	$3,237	$3,115	$2,527	$2,207	$1,993
2043	$5,525	$3,931	$3,265	$3,107	$2,520	$2,201	$1,988
2044	$5,591	$3,978	$3,303	$3,099	$2,513	$2,195	$1,983
2045	$5,640	$4,013	$3,333	$3,091	$2,507	$2,189	$1,978

* Utility-Scale Solar PV might not be applicable with high penetrations of DG-PV.

Table A-50. Replacement Resource Capital Cost Assumptions w/o AFUDC: Maui, Lana'i, Moloka'i, Hawai'i Island 2031–2045 (2 of 4)

Nominal $/kW	Replacement Resource Capital Cost Assumptions: Maui, Lana'i, Moloka'i, Hawai'i Island						
Technology	DG Solar PV	Simple Cycle Gas	Biomass	Biomass	Geothermal	Internal Combustion	Internal Combustion
Size (MW)	DG-PV	20.5	1	20	20	1	9
Fuel	n/a	Gas / Oil	Biomass	Biomass	n/a	Oil	Gas / Oil
Island	Hawai'i, Maui, Lana'i, Moloka'i	Hawai'i Maui	Lana'i, Moloka'i	Hawai'i Maui	Hawai'i Maui	Lana'i, Moloka'i	Hawai'i Maui
2016	$3,985	$3,586†	$7,000†	$5,251†	$8,804†	$10,394†	$5,407†
2017	$3,753	$3,634†	$6,773†	$5,081†	$8,963†	$10,532†	$5,479†
2018	$3,609	$3,655	$6,870†	$5,153†	$9,124†	$10,593†	$5,510†
2019	$3,492	$3,702	$6,970	$5,228	$9,289	$10,731	$5,582
2020	$3,394	$3,747	$7,065	$5,299	$9,456	$10,859	$5,649
2021	$3,318	$3,795	$7,167	$5,376	$9,626	$11,000	$5,722
2022	$3,251	$3,844	$7,273	$5,455	$9,799	$11,142	$5,796
2023	$3,192	$3,892	$7,375	$5,532	$9,976	$11,280	$5,868
2024	$3,142	$3,936	$7,477	$5,608	$10,155	$11,408	$5,935
2025	$3,100	$3,981	$7,589	$5,692	$10,338	$11,540	$6,003
2026	$3,065	$4,023	$7,692	$5,770	$10,524	$11,661	$6,066
2027	$3,034	$4,082	$7,804	$5,853	$10,713	$11,832	$6,155
2028	$3,007	$4,140	$7,918	$5,939	$10,906	$12,000	$6,243
2029	$2,982	$4,194	$8,030	$6,023	$11,103	$12,157	$6,324
2030	$2,962	$4,251	$8,142	$6,107	$11,302	$12,322	$6,410

† = Resource is not available this year.

Table A-51. Replacement Resource Capital Cost Assumptions w/o AFUDC: Maui, Lana'i, Moloka'i, Hawai'i Island 2016–2030 (3 of 4)

Nominal $/kW	Replacement Resource Capital Cost Assumptions: Maui, Lana'i, Moloka'i, Hawai'i Island						
Technology	DG Solar PV	Simple Cycle Gas	Biomass	Biomass	Geothermal	Internal Combustion	Internal Combustion
Size (MW)	DG-PV	20.5	1	20	20	1	9
Fuel	n/a	Gas / Oil	Biomass	Biomass	n/a	Oil	Gas / Oil
Island	Hawai'i, Maui, Lana'i, Moloka'i	Hawai'i Maui	Lana'i, Moloka'i	Hawai'i Maui	Hawai'i Maui	Lana'i, Moloka'i	Hawai'i Maui
2031	$2,955	$4,311	$8,256	$6,192	$11,506	$12,494	$6,500
2032	$2,947	$4,371	$8,370	$6,278	$11,713	$12,668	$6,590
2033	$2,939	$4,436	$8,493	$6,370	$11,924	$12,856	$6,688
2034	$2,931	$4,499	$8,609	$6,458	$12,138	$13,040	$6,783
2035	$2,924	$4,571	$8,728	$6,546	$12,357	$13,250	$6,893
2036	$2,916	$4,641	$8,842	$6,632	$12,579	$13,453	$6,998
2037	$2,908	$4,717	$8,964	$6,724	$12,806	$13,672	$7,112
2038	$2,901	$4,792	$9,079	$6,810	$13,036	$13,890	$7,226
2039	$2,893	$4,873	$9,192	$6,895	$13,271	$14,123	$7,347
2040	$2,885	$4,947	$9,296	$6,973	$13,510	$14,338	$7,459
2041	$2,878	$5,036	$9,464	$7,098	$13,753	$14,596	$7,593
2042	$2,870	$5,126	$9,634	$7,226	$14,001	$14,859	$7,730
2043	$2,863	$5,219	$9,807	$7,356	$14,253	$15,126	$7,869
2044	$2,855	$5,313	$9,984	$7,489	$14,509	$15,398	$8,010
2045	$2,848	$5,408	$10,164	$7,624	$14,770	$15,676	$8,154

Table A-52. Replacement Resource Capital Cost Assumptions w/o AFUDC: Maui, Lana'i, Moloka'i, Hawai'i Island 2031–2045 (4 of 4)

Replacement Resource Construction Expenditure Profiles: O'ahu

	Replacement Resource Construction Expenditure Profiles: O'ahu						
Years Before Commercial Operation Date	Onshore Wind	Offshore Wind Floating Platform	Onshore Wind + Cable	Onshore Wind + Cable	Utility-Scale Solar PV	DG Solar PV	Solar CSP w/ 10 hours storage
–5	00%	00%	00%	00%	00%	n/a	00%
–4	00%	00%	00%	00%	00%	n/a	00%
–3	00%	20%	20%	20%	00%	n/a	00%
–2	10%	40%	40%	40%	10%	n/a	10%
–1	90%	40%	40%	40%	90%	n/a	90%
Total COD	100%	100%	100%	100%	100%	n/a	100%

Table A-53. Replacement Resource Construction Expenditure Profiles: O'ahu (1 of 2)

	Replacement Resource Construction Expenditure Profiles: O'ahu						
Years Before Commercial Operation Date	Combined Cycle Gas	Combined Cycle Gas	Simple Cycle Gas	Biomass	Internal Combustion	Internal Combustion	Internal Combustion
–5	00%	00%	00%	00%	00%	00%	00%
–4	15%	10%	00%	00%	00%	00%	00%
–3	35%	35%	15%	00%	15%	15%	00%
–2	35%	40%	65%	10%	65%	65%	65%
–1	15%	15%	20%	90%	20%	20%	35%
Total COD	100%	100%	100%	100%	100%	100%	100%

Table A-54. Replacement Resource Construction Expenditure Profiles: O'ahu (2 of 2)

Replacement Resource Construction Expenditure Profiles: Maui, Lana'i, Moloka'i, Hawai'i Island

	Replacement Resource Construction Expenditure Profiles: Maui, Lana'i, Moloka'i, Hawai'i Island						
Years Before Commercial Operation Date	Onshore Wind	Onshore Wind	Onshore Wind	Utility-Scale Solar PV	Utility-Scale Solar PV	Utility-Scale Solar PV	Utility-Scale Solar PV
–5	00%	00%	00%	00%	00%	00%	00%
–4	00%	00%	00%	00%	00%	00%	00%
–3	00%	00%	00%	00%	00%	00%	00%
–2	10%	10%	10%	00%	10%	10%	10%
–1	90%	90%	90%	100%	90%	90%	90%
Total COD	100%	100%	100%	100%	100%	100%	100%

Table A-55. Replacement Resource Construction Expenditure Profiles: Maui, Lana'i, Moloka'i, Hawai'i Island (1 of 2)

	Replacement Resource Construction Expenditure Profiles: Maui, Lana'i, Moloka'i, Hawai'i Island						
Years Before Commercial Operation Date	DG Solar PV	Simple Cycle Gas	Biomass	Biomass	Geothermal	Internal Combustion	Internal Combustion
–5	n/a	00%	00%	00%	00%	00%	00%
–4	n/a	00%	00%	00%	00%	00%	00%
–3	n/a	20%	25%	20%	00%	25%	20%
–2	n/a	65%	60%	65%	40%	60%	65%
–1	n/a	15%	15%	15%	60%	15%	15%
Total COD	n/a	100%	100%	100%	100%	100%	100%

Table A-56. Replacement Resource Construction Expenditure Profiles: Maui, Lana'i, Moloka'i, Hawai'i Island (2 of 2)

Energy Storage Cost Assumptions: Inertia and Contingency Applications

Capital cost in nominal $/kWh (without interconnection or AFUDC)

Nominal $/kWh	Energy Storage Cost Assumptions: Inertia and Contingency Applications					
Application	Inertia	Contingency				
Size (MW)	10	1	5	20	50	100
Technology	Flywheel	Lithium Ion				
Duration Hours	0.25	0.5				
Turnaround Efficiency	85%	81%				
Discharge Cycles Per Year	15,000	Up to 10				
Depth of Discharge	100%	Up to 100%				
Plant Life Years	15%	15				
2016	$9,400	$1,506	$1,506	$1,506	$1,506	$1,506
2017	$8,632	$1,383	$1,383	$1,383	$1,383	$1,383
2018	$7,877	$1,262	$1,262	$1,262	$1,262	$1,262
2019	$7,253	$1,162	$1,162	$1,162	$1,162	$1,162
2020	$6,729	$1,078	$1,078	$1,078	$1,078	$1,078
2021	$6,317	$1,012	$1,012	$1,012	$1,012	$1,012
2022	$5,972	$957	$957	$957	$957	$957
2023	$5,678	$910	$910	$910	$910	$910
2024	$5,429	$870	$870	$870	$870	$870
2025	$5,214	$835	$835	$835	$835	$835
2026	$5,029	$806	$806	$806	$806	$806
2027	$4,869	$780	$780	$780	$780	$780
2028	$4,730	$758	$758	$758	$758	$758
2029	$4,609	$738	$738	$738	$738	$738
2030	$4,503	$721	$721	$721	$721	$721

Table A-57. Energy Storage Cost Assumptions: Inertia and Contingency Applications 2016–2030 (1 of 2)

Nominal $/kWh	Energy Storage Cost Assumptions: Inertia and Contingency Applications					
Application	Inertia	Contingency				
Size (MW)	10	1	5	20	50	100
Technology	Flywheel	Lithium Ion				
Duration Hours	0.25	0.5				
Turnaround Efficiency	85%	81%				
Discharge Cycles Per Year	15,000	Up to 10				
Depth of Discharge	100%	Up to 100%				
Plant Life Years	15%	15				
2031	$9,400	$1,506	$1,506	$1,506	$1,506	$1,506
2032	$8,632	$1,383	$1,383	$1,383	$1,383	$1,383
2033	$7,877	$1,262	$1,262	$1,262	$1,262	$1,262
2034	$7,253	$1,162	$1,162	$1,162	$1,162	$1,162
2035	$6,729	$1,078	$1,078	$1,078	$1,078	$1,078
2036	$6,317	$1,012	$1,012	$1,012	$1,012	$1,012
2037	$5,972	$957	$957	$957	$957	$957
2038	$5,678	$910	$910	$910	$910	$910
2039	$5,429	$870	$870	$870	$870	$870
2040	$5,214	$835	$835	$835	$835	$835
2041	$5,029	$806	$806	$806	$806	$806
2042	$4,869	$780	$780	$780	$780	$780
2043	$4,730	$758	$758	$758	$758	$758
2044	$4,609	$738	$738	$738	$738	$738
2045	$4,503	$721	$721	$721	$721	$721

Table A-58. Energy Storage Cost Assumptions: Inertia and Contingency Applications 2031–2045 (2 of 2)

Energy Storage Cost Assumptions: Regulation / Renewable Smoothing Applications

Capital cost in nominal $/kWh (without interconnection or AFUDC)

Nominal $/kWh	Energy Storage Cost Assumptions: Regulation / Renewable Smoothing Applications				
Size (MW)	1	5	20	50	100
Technology	Lithium Ion				
Duration Hours	1.0				
Turnaround Efficiency	81%				
Discharge Cycles Per Year	Up to 15,000				
Depth of Discharge	Up to 20%				
Plant Life Years	15				
2016	$1,083	$1,083	$1,083	$1,083	$1,083
2017	$999	$999	$999	$999	$999
2018	$914	$914	$914	$914	$914
2019	$843	$843	$843	$843	$843
2020	$782	$782	$782	$782	$782
2021	$737	$737	$737	$737	$737
2022	$698	$698	$698	$698	$698
2023	$666	$666	$666	$666	$666
2024	$638	$638	$638	$638	$638
2025	$614	$614	$614	$614	$614
2026	$594	$594	$594	$594	$594
2027	$576	$576	$576	$576	$576
2028	$560	$560	$560	$560	$560
2029	$547	$547	$547	$547	$547
2030	$535	$535	$535	$535	$535

Table A-59. Energy Storage Cost Assumptions: Regulation / Renewable Smoothing 2016–2030 (1 of 2)

Nominal $/kWh	Energy Storage Cost Assumptions: Regulation / Renewable Smoothing Applications				
Size (MW)	1	5	20	50	100
Technology	Lithium Ion				
Duration Hours	1.0				
Turnaround Efficiency	81%				
Discharge Cycles Per Year	Up to 15,000				
Depth of Discharge	Up to 20%				
Plant Life Years	15				
2031	$525	$525	$525	$525	$525
2032	$516	$516	$516	$516	$516
2033	$508	$508	$508	$508	$508
2034	$500	$500	$500	$500	$500
2035	$494	$494	$494	$494	$494
2036	$488	$488	$488	$488	$488
2037	$483	$483	$483	$483	$483
2038	$479	$479	$479	$479	$479
2039	$475	$475	$475	$475	$475
2040	$471	$471	$471	$471	$471
2041	$468	$468	$468	$468	$468
2042	$465	$465	$465	$465	$465
2043	$463	$463	$463	$463	$463
2044	$461	$461	$461	$461	$461
2045	$459	$459	$459	$459	$459

Table A-60. Energy Storage Cost Assumptions: Regulation / Renewable Smoothing Applications 2031–2045 (2 of 2)

Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications

Capital cost in nominal $/kWh (without interconnection or AFUDC)

Nominal $/kWh	Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications					
Application	Load Shifting					Grid Support
Size (MW)	1	5	20	50	100	5
Technology	Lithium Ion					Lithium Ion
Duration Hours	4.0					2.0
Turnaround Efficiency	88%					81%
Discharge Cycles Per Year	Up to 365					Up to 365
Depth of Discharge	Up to 100%					Up to 100%
Plant Life Years	15					15
2016	$660	$660	$660	$660	$660	$1,083
2017	$615	$615	$615	$615	$615	$999
2018	$565	$565	$565	$565	$565	$914
2019	$524	$524	$524	$524	$524	$843
2020	$487	$487	$487	$487	$487	$782
2021	$461	$461	$461	$461	$461	$737
2022	$440	$440	$440	$440	$440	$698
2023	$422	$422	$422	$422	$422	$666
2024	$406	$406	$406	$406	$406	$638
2025	$393	$393	$393	$393	$393	$614
2026	$382	$382	$382	$382	$382	$594
2027	$372	$372	$372	$372	$372	$576
2028	$363	$363	$363	$363	$363	$560
2029	$355	$355	$355	$355	$355	$547
2030	$349	$349	$349	$349	$349	$535

Table A-61. Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications 2016–2030 (1 of 2)

Nominal $/kWh	Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications					
Application	Load Shifting					Grid Support
Size (MW)	1	5	20	50	100	5
Technology	Lithium Ion					Lithium Ion
Duration Hours	4.0					2.0
Turnaround Efficiency	88%					81%
Discharge Cycles Per Year	Up to 365					Up to 365
Depth of Discharge	Up to 100%					Up to 100%
Plant Life Years	15					15
2031	$343	$343	$343	$343	$343	$525
2032	$338	$338	$338	$338	$338	$516
2033	$333	$333	$333	$333	$333	$508
2034	$329	$329	$329	$329	$329	$500
2035	$326	$326	$326	$326	$326	$494
2036	$323	$323	$323	$323	$323	$488
2037	$320	$320	$320	$320	$320	$483
2038	$317	$317	$317	$317	$317	$479
2039	$315	$315	$315	$315	$315	$475
2040	$313	$313	$313	$313	$313	$471
2041	$312	$312	$312	$312	$312	$468
2042	$310	$310	$310	$310	$310	$465
2043	$309	$309	$309	$309	$309	$463
2044	$307	$307	$307	$307	$307	$461
2045	$306	$306	$306	$306	$306	$459

Table A-62. Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications 2031–2045 (2 of 2)

Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications

Capital cost in nominal $/kWh (without interconnection or AFUDC)

Nominal $/kWh	Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications						
Application	Residential		Commercial		Long Duration Load Shifting		
Size (MW)	0.002		0.050		30.000	30.000	50.000
Technology	Lithium Ion w/o inverter	Lithium Ion w/ inverter & Balance of Plant	Lithium Ion		Lithium Ion	Pumped-Storage Hydro	Pumped-Storage Hydro
Duration Hours	4.0		2.0		6.0		
Turnaround Efficiency	88%		88%		80%		
Discharge Cycles Per Year	Up to 365		Up to 365		Up to 365		
Depth of Discharge	Up to 100%		Up to 100%		Up to 100%		
Plant Life Years	10		10		15	40	40
2016	$506	$1,026	$553	$553	$530	$583	$583
2017	$465	$965	$511	$511	$493	$594	$594
2018	$416	$892	$461	$461	$454	$605	$605
2019	$373	$829	$417	$417	$421	$615	$615
2020	$335	$774	$378	$378	$391	$626	$626
2021	$317	$751	$359	$359	$371	$638	$638
2022	$303	$732	$342	$342	$353	$649	$649
2023	$290	$717	$328	$328	$339	$661	$661
2024	$280	$705	$316	$316	$326	$673	$673
2025	$270	$695	$305	$305	$316	$685	$685
2026	$262	$688	$296	$296	$306	$697	$697
2027	$256	$682	$289	$289	$298	$710	$710
2028	$250	$678	$282	$282	$291	$723	$723
2029	$245	$675	$276	$276	$285	$736	$736
2030	$240	$673	$271	$271	$280	$749	$749

Table A-63. Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications 2016–2030 (1 of 2)

Nominal $/kWh	Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications						
Application	Residential		Commercial		Long Duration Load Shifting		
Size (MW)	0.002		0.050		30.000	30.000	50.000
Technology	Lithium Ion w/o inverter	Lithium Ion w/ inverter & Balance of Plant	Lithium Ion		Lithium Ion	Pumped-Storage Hydro	Pumped-Storage Hydro
Duration Hours	4.0		2.0		6.0		
Turnaround Efficiency	88%		88%		80%		
Discharge Cycles Per Year	Up to 365		Up to 365		Up to 365		
Depth of Discharge	Up to 100%		Up to 100%		Up to 100%		
Plant Life Years	10		10		15	40	40
2016	$236	$672	$267	$267	$275	$762	$762
2017	$232	$672	$263	$263	$271	$776	$776
2018	$229	$672	$259	$259	$268	$790	$790
2019	$227	$674	$256	$256	$264	$804	$804
2020	$224	$676	$253	$253	$262	$819	$819
2021	$222	$678	$251	$251	$259	$833	$833
2022	$220	$681	$249	$249	$257	$848	$848
2023	$218	$684	$247	$247	$255	$864	$864
2024	$217	$688	$245	$245	$253	$879	$879
2025	$216	$692	$243	$243	$252	$895	$895
2026	$214	$696	$242	$242	$250	$911	$911
2027	$213	$701	$241	$241	$249	$928	$928
2028	$212	$706	$240	$240	$248	$944	$944
2029	$211	$712	$239	$239	$247	$961	$961
2030	$211	$717	$238	$238	$246	$979	$979

Table A-64. Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications 2030–2045 (2 of 2)

Energy Storage Cost Assumptions: Inertia and Contingency Applications

Capital cost in nominal $/kW (without interconnection or AFUDC)

Nominal $/kWh	Energy Storage Cost Assumptions: Inertia and Contingency Applications					
Application	Inertia	Contingency				
Size (MW)	10	1	5	20	50	100
Technology	Flywheel	Lithium Ion				
Duration Hours	0.25	0.5				
Turnaround Efficiency	85%	81%				
Discharge Cycles Per Year	15,000	Up to 10				
Depth of Discharge	100%	Up to 100%				
Plant Life Years	15	15				
2016	$2,350	$753	$753	$753	$753	$753
2017	$2,158	$692	$692	$692	$692	$692
2018	$1,969	$631	$631	$631	$631	$631
2019	$1,813	$581	$581	$581	$581	$581
2020	$1,682	$539	$539	$539	$539	$539
2021	$1,579	$506	$506	$506	$506	$506
2022	$1,493	$478	$478	$478	$478	$478
2023	$1,420	$455	$455	$455	$455	$455
2024	$1,357	$435	$435	$435	$435	$435
2025	$1,304	$418	$418	$418	$418	$418
2026	$1,257	$403	$403	$403	$403	$403
2027	$1,217	$390	$390	$390	$390	$390
2028	$1,183	$379	$379	$379	$379	$379
2029	$1,152	$369	$369	$369	$369	$369
2030	$1,126	$361	$361	$361	$361	$361

Table A-65. Energy Storage Cost Assumptions: Inertia and Contingency Applications 2016–2030 (1 of 2)

Nominal $/kWh	Energy Storage Cost Assumptions: Inertia and Contingency Applications					
Application	Inertia	Contingency				
Size (MW)	10	1	5	20	50	100
Technology	Flywheel	Lithium Ion				
Duration Hours	0.25	0.5				
Turnaround Efficiency	85%	81%				
Discharge Cycles Per Year	15,000	Up to 10				
Depth of Discharge	100%	Up to 100%				
Plant Life Years	15	15				
2031	$1,102	$353	$353	$353	$353	$353
2032	$1,082	$347	$347	$347	$347	$347
2033	$1,064	$341	$341	$341	$341	$341
2034	$1,048	$336	$336	$336	$336	$336
2035	$1,033	$331	$331	$331	$331	$331
2036	$1,021	$327	$327	$327	$327	$327
2037	$1,009	$323	$323	$323	$323	$323
2038	$999	$320	$320	$320	$320	$320
2039	$991	$317	$317	$317	$317	$317
2040	$983	$315	$315	$315	$315	$315
2041	$975	$313	$313	$313	$313	$313
2042	$969	$311	$311	$311	$311	$311
2043	$963	$309	$309	$309	$309	$309
2044	$958	$307	$307	$307	$307	$307
2045	$954	$306	$306	$306	$306	$306

Table A-66. Energy Storage Cost Assumptions: Inertia and Contingency Applications 2031–2045 (2 of 2)

Energy Storage Cost Assumptions: Regulation / Renewable Smoothing Applications

Capital cost in nominal $/kW (without interconnection or AFUDC)

Nominal $/kWh	Energy Storage Cost Assumptions: Regulation / Renewable Smoothing Applications				
Size (MW)	1	5	20	50	100
Technology	Lithium Ion				
Duration Hours	1.0				
Turnaround Efficiency	81%				
Discharge Cycles Per Year	Up to 15,000				
Depth of Discharge	Up to 20%				
Plant Life Years	15				
2016	$1,083	$1,083	$1,083	$1,083	$1,083
2017	$999	$999	$999	$999	$999
2018	$914	$914	$914	$914	$914
2019	$843	$843	$843	$843	$843
2020	$782	$782	$782	$782	$782
2021	$737	$737	$737	$737	$737
2022	$698	$698	$698	$698	$698
2023	$666	$666	$666	$666	$666
2024	$638	$638	$638	$638	$638
2025	$614	$614	$614	$614	$614
2026	$594	$594	$594	$594	$594
2027	$576	$576	$576	$576	$576
2028	$560	$560	$560	$560	$560
2029	$547	$547	$547	$547	$547
2030	$535	$535	$535	$535	$535

Table A-67. Energy Storage Cost Assumptions: Regulation / Renewable Smoothing Applications 2016–2030 (1 of 2)

Nominal $/kWh	Energy Storage Cost Assumptions: Regulation / Renewable Smoothing Applications				
Size (MW)	1	5	20	50	100
Technology	Lithium Ion				
Duration Hours	1.0				
Turnaround Efficiency	81%				
Discharge Cycles Per Year	Up to 15,000				
Depth of Discharge	Up to 20%				
Plant Life Years	15				
2031	$525	$525	$525	$525	$525
2032	$516	$516	$516	$516	$516
2033	$508	$508	$508	$508	$508
2034	$500	$500	$500	$500	$500
2035	$494	$494	$494	$494	$494
2036	$488	$488	$488	$488	$488
2037	$483	$483	$483	$483	$483
2038	$479	$479	$479	$479	$479
2039	$475	$475	$475	$475	$475
2040	$471	$471	$471	$471	$471
2041	$468	$468	$468	$468	$468
2042	$465	$465	$465	$465	$465
2043	$463	$463	$463	$463	$463
2044	$461	$461	$461	$461	$461
2045	$459	$459	$459	$459	$459

Table A-68. Energy Storage Cost Assumptions: Regulation / Renewable Smoothing Applications 2031–2045 (2 of 2)

Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications

Capital cost in nominal $/kW (without interconnection or AFUDC)

Nominal $/kWh	Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications					
Application	Load Shifting					Grid Support
Size (MW)	1	5	20	50	100	5
Technology	Lithium Ion					Lithium Ion
Duration Hours	4.0					2.0
Turnaround Efficiency	88%					81%
Discharge Cycles Per Year	Up to 365					Up to 365
Depth of Discharge	Up to 100%					Up to 100%
Plant Life Years	15					15
2016	$2,640	$2,640	$2,640	$2,640	$2,640	$2,166
2017	$2,458	$2,458	$2,458	$2,458	$2,458	$1,998
2018	$2,261	$2,261	$2,261	$2,261	$2,261	$1,827
2019	$2,095	$2,095	$2,095	$2,095	$2,095	$1,686
2020	$1,948	$1,948	$1,948	$1,948	$1,948	$1,565
2021	$1,846	$1,846	$1,846	$1,846	$1,846	$1,474
2022	$1,760	$1,760	$1,760	$1,760	$1,760	$1,397
2023	$1,687	$1,687	$1,687	$1,687	$1,687	$1,332
2024	$1,625	$1,625	$1,625	$1,625	$1,625	$1,276
2025	$1,572	$1,572	$1,572	$1,572	$1,572	$1,228
2026	$1,526	$1,526	$1,526	$1,526	$1,526	$1,187
2027	$1,486	$1,486	$1,486	$1,486	$1,486	$1,152
2028	$1,452	$1,452	$1,452	$1,452	$1,452	$1,121
2029	$1,422	$1,422	$1,422	$1,422	$1,422	$1,094
2030	$1,395	$1,395	$1,395	$1,395	$1,395	$1,070

Table A-69. Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications 2016–2030 (1 of 2)

Nominal $/kWh	Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications					
Application	Load Shifting					Grid Support
Size (MW)	1	5	20	50	100	5
Technology	Lithium Ion					Lithium Ion
Duration Hours	4.0					2.0
Turnaround Efficiency	88%					81%
Discharge Cycles Per Year	Up to 365					Up to 365
Depth of Discharge	Up to 100%					Up to 100%
Plant Life Years	15					15
2031	$1,372	$1,372	$1,372	$1,372	$1,372	$1,049
2032	$1,352	$1,352	$1,352	$1,352	$1,352	$1,031
2033	$1,334	$1,334	$1,334	$1,334	$1,334	$1,015
2034	$1,318	$1,318	$1,318	$1,318	$1,318	$1,001
2035	$1,304	$1,304	$1,304	$1,304	$1,304	$988
2036	$1,291	$1,291	$1,291	$1,291	$1,291	$977
2037	$1,280	$1,280	$1,280	$1,280	$1,280	$967
2038	$1,270	$1,270	$1,270	$1,270	$1,270	$958
2039	$1,261	$1,261	$1,261	$1,261	$1,261	$950
2040	$1,253	$1,253	$1,253	$1,253	$1,253	$943
2041	$1,246	$1,246	$1,246	$1,246	$1,246	$937
2042	$1,240	$1,240	$1,240	$1,240	$1,240	$931
2043	$1,234	$1,234	$1,234	$1,234	$1,234	$926
2044	$1,229	$1,229	$1,229	$1,229	$1,229	$921
2045	$1,224	$1,224	$1,224	$1,224	$1,224	$917

Table A-70. Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications 2031–2045 (2 of 2)

Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications

Capital cost in nominal $/kW (without interconnection or AFUDC)

Nominal $/kWh	Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications						
Application	Residential		Commercial		Long Duration Load Shifting		
Size (MW)	0.002		0.050		30.000	30.000	50.000
Technology	Lithium Ion w/o inverter	Lithium Ion w/ inverter & Balance of Plant	Lithium Ion		Lithium Ion	Pumped-Storage Hydro	Pumped-Storage Hydro
Duration Hours	4.0		2.0		6.0		
Turnaround Efficiency	88%		88%		80%		
Discharge Cycles Per Year	Up to 365		Up to 365		Up to 365		
Depth of Discharge	Up to 100%		Up to 100%		Up to 100%		
Plant Life Years	10		10		15	40	40
2016	$2,023	$4,103	$1,106	$1,106	$3,180	$3,500	$3,500
2017	$1,858	$3,860	$1,021	$1,021	$2,960	$3,563	$3,563
2018	$1,663	$3,569	$922	$922	$2,723	$3,627	$3,627
2019	$1,492	$3,317	$834	$834	$2,523	$3,692	$3,692
2020	$1,340	$3,096	$757	$757	$2,346	$3,759	$3,759
2021	$1,270	$3,004	$717	$717	$2,223	$3,827	$3,827
2022	$1,211	$2,929	$684	$684	$2,120	$3,895	$3,895
2023	$1,161	$2,869	$656	$656	$2,032	$3,966	$3,966
2024	$1,118	$2,820	$631	$631	$1,957	$4,037	$4,037
2025	$1,081	$2,782	$611	$611	$1,893	$4,110	$4,110
2026	$1,050	$2,751	$593	$593	$1,838	$4,184	$4,184
2027	$1,023	$2,728	$577	$577	$1,790	$4,259	$4,259
2028	$999	$2,711	$564	$564	$1,748	$4,336	$4,336
2029	$978	$2,699	$552	$552	$1,712	$4,414	$4,414
2030	$960	$2,691	$542	$542	$1,680	$4,493	$4,493

Table A-71. Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications 2016–2030 (1 of 2)

Nominal $/kWh	Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications						
Application	Residential		Commercial		Long Duration Load Shifting		
Size (MW)	0.002		0.050		30.000	30.000	50.000
Technology	Lithium Ion w/o inverter	Lithium Ion w/ inverter & Balance of Plant	Lithium Ion		Lithium Ion	Pumped-Storage Hydro	Pumped-Storage Hydro
Duration Hours	4.0		2.0		6.0		
Turnaround Efficiency	88%		88%		80%		
Discharge Cycles Per Year	Up to 365		Up to 365		Up to 365		
Depth of Discharge	Up to 100%		Up to 100%		Up to 100%		
Plant Life Years	10		10		15	40	40
2016	$944	$2,687	$533	$533	$1,652	$4,574	$4,574
2017	$930	$2,687	$525	$525	$1,628	$4,656	$4,656
2018	$917	$2,689	$518	$518	$1,606	$4,740	$4,740
2019	$907	$2,695	$512	$512	$1,587	$4,825	$4,825
2020	$897	$2,702	$506	$506	$1,570	$4,912	$4,912
2021	$888	$2,712	$502	$502	$1,555	$5,001	$5,001
2022	$881	$2,723	$497	$497	$1,541	$5,091	$5,091
2023	$874	$2,737	$493	$493	$1,529	$5,182	$5,182
2024	$868	$2,752	$490	$490	$1,519	$5,276	$5,276
2025	$862	$2,768	$487	$487	$1,509	$5,370	$5,370
2026	$857	$2,786	$484	$484	$1,501	$5,467	$5,467
2027	$853	$2,805	$482	$482	$1,493	$5,566	$5,566
2028	$849	$2,825	$479	$479	$1,486	$5,666	$5,666
2029	$846	$2,846	$478	$478	$1,480	$5,768	$5,768
2030	$842	$2,869	$476	$476	$1,475	$5,872	$5,872

Table A-72. Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications 2030–2045 (2 of 2)

DEMAND RESPONSE (DR)

The Black & Veatch modeling tool produces Demand Response modeling data to evaluate DR for reducing energy production costs, deferring capital expenditures, and improving grid stability. There are a number of key inputs and constraints unique to the Demand Response modeling data.

The primary modeling data assumption was the Navigant Potential Study. The study assists in forecasting the quantity of MW by customer type or end-use devices (for example, water heaters, air conditioning, electric vehicle changers, and pumps) that the Companies can target in each DR program. Analysis used hourly load profiles by customer type and end-uses to estimate the DR potential. The model separates hourly and yearly result data by DR program, market segment, end use, and building type. Under Company guidance, the model modified start dates for various programs to represent planned timelines for implementing programs to align with planned infrastructure upgrades.

The projected demand profiles (provided by the Companies) is another key input. The potential for DR programs is dictated by daily demand. For example, air conditioning loads increase on hot days, thereby providing greater potential for air conditioners to participate in a DR program.

Our model also included system security constraints (provided by the Companies) for DR to improve grid stability. These constraints focus on eliminating under-frequency load shedding (UFLS) after a contingency event (such as a unit trip). The constraints included data on net system load, kinetic energy, and the largest contingency. This data enabled the model to determine the amount of Fast Frequency Response and segregated customer end-use devices necessary to handle the contingency.

Perhaps the most important DR modeling assumption is the end-use overlap logic that drives the potential for all of DR programs. The Navigant Potential Study determined the maximum potential of end-use devices to provide specific services (fast frequency response, non-spin auto response, regulating reserves, load building, and load reduction) through specific DR programs (time of use, day ahead load shift, real-time pricing, critical peak incentive, minimum load building, fast frequency response, non-spin auto response, and regulating reserves).

A DR portfolio of individual DR programs must consider that end-use devices can only provide one service at a time. (For example, a water heater cannot simultaneously provide both fast frequency response and regulating reserve. Thus, each DR program must be managed to prevent this double allocation of end-use devices. The allocation, however, is complex because some system constraints are dynamic. (For example, fast frequency response is dynamic.) Given the finite demand response potential, the optimal allocation often requires layering so that all constraints are satisfied and that the DR potential is not over allocated.

Black & Veatch and the Hawaiian Electric Demand Response group have ascertained the most cost effective DR portfolio possible for each given PSIP case. The model aggregated DR output data up to system level impact based on the DR programs ability to provide services, then applied this aggregated impact profile in other team's models. The output data include a modified demand shape, the potential by hour for DR to provide spin, reductions in must-run units, deferred capital expenditures, and the costs of the DR programs. The modified load shape is defined by the gross load after factoring the effects of load shifting DR programs. A DR program's ability to provide spin is given as a profile for every hour, and allows for reduced unit commitments and reduced fuel costs. Deferred capital expenditures translate to delaying the installation of a replacement generation unit or a reduction in the size of a new battery. The model provides the annual cost of implementing these DR programs.

B. Responding to Party Input

We have read every filing submitted by the stakeholders, assimilated the comments, and determined how best to incorporate them into our analysis and in our process for creating the Updated PSIPs.

To streamline how we responded to input from the Parties for this PSIP Update Interim Status Report, we organized the input comments into 15 topics. These 15 topics are:

Utility Business Model	Value of Solar	Transparency
Resource Inputs	Optimization Framework	Cases & Sensitivities
System Security Criteria	DER / DR Optimization	Risks
Customer Bill Impacts & Relevant Metrics	LNG	Fossil Generation Upgrades
Stakeholder Input	Energy Efficiency / Electric Transport	Inter-Island Transmission

Each topic contains four parts: a bulleted summary of the input we received for the topic; a discussion of the actions we took or will take on this topic; a list of the Parties who submitted input for the topic; and indication of the status of our actions.

Utility Business Model

Summary Description of this Topic

- The Companies need to transform themselves to move forward and enable the new Hawaiian energy landscape.
- Topic was stated in the Commission's Inclinations, but was not specified in Order No. 33320.

Our Action Regarding this Topic

A business model discussion would include at least these three key criteria:

- What is the optimal design and operation of Hawai'i's electric system in the future to achieve Hawai'i's energy goals (our preferred plans will attempt to answer a significant part of this question)?
- What is the optimal role of the Companies in this future?
- How the Companies are best to carry out this role?

A discussion surrounding the utility business model is not currently part of this docket. In addition, NextEra and Hawaiian Electric have responded to the question of a sustainable business model in the merger docket (Applicants Exhibit 42, Docket 2015-0022).

Stakeholders Submitting Input on this Topic

County of Hawai'i (CoH)
County of Maui (CoM)
Blue Planet Foundation
DERC
Hawai'i Solar Energy Association (HSEA)
Life of the Land (LOL)
Paniolo Power
Sierra Club
The Alliance for Solar Choice (TASC)
Ulupono Initiative

Status of this Topic

Out of scope of this docket, and thus not being considered as part of the Updated PSIPs.

Value of Solar

Summary Description of this Topic

- The avoided cost methodology does not fully capture the value of solar; as such, a comprehensive study is recommended.

Our Action Regarding this Topic

We plan to cover this topic in Phase 2 of our DER docket.

Stakeholders Submitting Input on this Topic

Distributed Energy Resources Council of Hawai'i (DERC)
SunEdison (First Wind)
SunPower
The Alliance for Solar Choice (TASC)

Status of this Topic

Out of scope of this docket, and thus not being considered as part of the Updated PSIPs.

Transparency

Summary Description of this Topic

Parties are generally concerned about not understanding or not being informed about:

- How the models work and interact with each other.
- How the assumptions were created and which assumptions were used.
- How the methodologies were developed.
- How decisions are made.
- How discrepancies are resolved.

Our Action Regarding this Topic

We are documenting all assumptions and modeling tools, and are establishing an FTP server for regular file sharing. We have and continue to document all methodologies and decision frameworks, and have included those in this interim report.

Stakeholders Submitting Input on this Topic

Consumer Advocate
County of Hawai‘i (CoH)
County of Maui (CoM)
Department of Business, Economic Development, and Tourism (DBEDT)
Blue Planet Foundation
Distributed Energy Resources Council of Hawai‘i (DERC)
Hawai‘i Gas
Life of the Land (LOL)
Paniolo Power
Renewable Energy Action Coalition of Hawai‘i (REACH)
SunPower
The Alliance for Solar Choice (TASC)
Ulupono Initiative

Status of this Topic

We implemented the FTP server well before the filing of this interim update. This PSIP Update Interim Status Report discusses all assumptions and methodologies.

Resource Inputs

Summary Description of this Topic

The Parties want assurance that all resource assumptions are reasonable and well grounded, such as:

- What is the actual amount of land available for wind resources in Maui?
- What is the most likely trajectory for fuel costs over next 20 years?
- What is the most accurate assumptions for capital costs for renewable resources?

Our Action Regarding this Topic

This PSIP Update Interim Status Report documents the process and the source of our resource assumptions. We will upload all resource assumptions to the FTP server as they are completed. We have also requested additional information from Paniolo Power, Hawai‘i Gas, and DERC about the initial resource inputs they already provided.

Stakeholders Submitting Input on this Topic

Consumer Advocate
County of Hawai‘i (CoH)
County of Maui (CoM)
Department of Business, Economic Development, and Tourism (DBEDT)
Blue Planet Foundation
Distributed Energy Resources Council of Hawai‘i (DERC)
Hawai‘i Gas
Hawai‘i Solar Energy Association (HSEA)
Life of the Land (LOL)
Paniolo Power
Renewable Energy Action Coalition of Hawai‘i (REACH)
Sierra Club
The Alliance for Solar Choice (TASC)

Status of this Topic

We have incorporated this topic into this PSIP Update Interim Status Report.

Decision Framework

Summary Description of this Topic

- Concerned that the logic for choosing the Preferred Plans (in our filed PSIPs) was not well articulated (for example, we didn't apply a decision framework).
- Discrete uncoordinated analysis resulted in suboptimal resource allocation, and the optimization steps are unclear.
- The process needs an optimization framework detailing an overarching logic and process that guides development paths and portfolios for specific goals (for example, rate reduction, low cost, and 100% RPS), and helps select the Preferred Plan that best accomplishes those goals.

Our Action Regarding this Topic

We have developed a detailed workflow and decision framework, and included a discussion of how we are using this framework to optimize our process and select a Preferred Plan.

Stakeholders Submitting Input on this Topic

County of Maui (CoM)
Department of Business, Economic Development, and Tourism (DBEDT)
Blue Planet Foundation
Distributed Energy Resources Council of Hawaiʻi (DERC)
Paniolo Power
Renewable Energy Action Coalition of Hawaiʻi (REACH)
SunPower
The Alliance for Solar Choice (TASC)

Status of this Topic

We have incorporated this topic into this PSIP Update Interim Status Report.

Cases and Sensitivities

Summary Description of this Topic

Concern that various cases and sensitivities will not be explored, such as:

- A least-cost case serving as a reference case (even if the case is not 100% RPS).
- Every alternative plan documents the value of incremental spending compared to the least-cost case.
- A sensitivity analysis of the system requirements for various levels.

Our Action Regarding this Topic

In this interim filing, we have clearly defined cases and their differentiating attributes, and demonstrated a cost delta across the various cases. As noted in multiple places in this filing, additional analysis is ongoing.

Stakeholders Submitting Input on this Topic

Consumer Advocate
County of Maui (CoM)
Department of Business, Economic Development, and Tourism (DBEDT)
Blue Planet Foundation
Hawai'i Gas
Hawai'i Solar Energy Association (HSEA)
Paniolo Power
Renewable Energy Action Coalition of Hawai'i (REACH)

Status of this Topic

We have incorporated this topic into this PSIP Update Interim Status Report.

System Security Criteria

Summary Description of this Topic

- The system security methodology and results published in the filed PSIPs are overly conservative and intended to limit DER adoption.
- The resolution of system-level constraints should emphasize safety, reliability, and power quality rather than economics.

Our Action Regarding this Topic

We are leveraging the analyses that was performed for the IDRPP Supplemental Filing to determine technology-neutral system security requirements for each resource plan. System security will not constrain any resource plan if and when these qualified DR/DER resources are available in sufficient quantities.

Stakeholders Submitting Input on this Topic

Consumer Advocate
Distributed Energy Resources Council of Hawai'i (DERC)
Life of the Land (LOL)
Renewable Energy Action Coalition of Hawai'i (REACH)
The Alliance for Solar Choice (TASC)

Status of this Topic

We have incorporated this topic into this PSIP Update Interim Status Report, and will further expand on it when we filed our Updated PSIPs.

DER and DR Optimization

Summary Description of this Topic

- Assurance that the PSIPs are coordinated with the DER and DR dockets.
- Assurance that we treat DER as a resource to be optimized (and not an end state), and that appropriate consideration be given to motivate customer adoption.
- DER must viewed as customer-centric solutions and recommend an in-depth study be conducted.
- Overarching goals provided by the Commission are reducing rates and ensuring a clean energy future while providing customer choice.

Our Action Regarding this Topic

We have documented our current DER/DR optimization process, and have explained the potential services that DER/DR can provide to the grid and how we plan to fully utilize them.

We will provide information about the tariff structure and implementation in our DER and DR dockets.

Stakeholders Submitting Input on this Topic

Consumer Advocate
County of Maui (CoM)
Department of Business, Economic Development, and Tourism (DBEDT)
Distributed Energy Resources Council of Hawai‘i (DERC)
Hawai‘i Solar Energy Association (HSEA)
Life of the Land (LOL)
Sierra Club
SunEdison (First Wind)
SunPower
Tawhiri
The Alliance for Solar Choice (TASC)
Ulupono Initiative

Status of this Topic

We have described our methodology in this PSIP Update Interim Status Report, and will provide specific values in our Updated PSIPs.

Risks

Summary Description of this Topic

- Assurance that all risks are properly documented and explored through the various portfolios and options.
- Concern about the risk that customers will bear the impact of stranded costs because of the chosen resource mix.
- Concern about the uncertainty of future fuel forecasts and the actual benefits of switching fuels in volatile environments.
- Assurance about the timing and realization of customer savings under various plans.

Our Action Regarding this Topic

We are developing a concise set of risk criteria to evaluate each alternative plan on an equal basis with similar objectives. We plan to explain this risk criteria and evaluation process and post it on our FTP server. We plan to include sensitivities that test key risk factors in our Updated PSIPs.

Stakeholders Submitting Input on this Topic

Consumer Advocate
County of Maui (CoM)
Department of Business, Economic Development, and Tourism (DBEDT)
Blue Planet Foundation
Distributed Energy Resources Council of Hawaiʻi (DERC)
Hawaiʻi Gas
Hawaiʻi Solar Energy Association (HSEA)
Paniolo Power
Renewable Energy Action Coalition of Hawaiʻi (REACH)
Ulupono Initiative

Status of this Topic

We will address this topic in our Updated PSIPs.

Customer Bill Impacts and Relevant Metrics

Summary Description of this Topic

- Reassurance that all plans are evaluated based on customer bill impact and near-term rate relief.
- State nominal impacts of any resource plan on customer bills.
- Consider developing bill impact estimates for various residential segments (such as customers who do and do not participate in distributed generation programs.

- Provide alternative portfolio comparisons with bill impacts (including a comparison to a least-cost option).

Our Action Regarding this Topic

Our Updated PSIPs will compare bill impacts. We will ensure that all customer bill impacts are shown in both nominal and real values, and will calculate bill impacts.

Stakeholders Submitting Input on this Topic

Consumer Advocate
County of Hawai‘i (CoH)
County of Maui (CoM)
Department of Business, Economic Development, and Tourism (DBEDT)
Life of the Land (LOL)
Paniolo Power
SunEdison (First Wind)
SunPower
Tawhiri
Ulupono Initiative

Status of this Topic

We will address this topic in our Updated PSIPs.

Liquefied Natural Gas (LNG)

Summary Description of this Topic

- Want an implementation and exit plan for LNG use, with minimal or no stranded costs that impact customers.
- Want significant savings demonstrated for using LNG as a bridge fuel when compared with directly investing in only renewable generation.
- Some parties do not consider LNG a feasible resource option because its not a renewable resource.

Our Action Regarding this Topic

We will develop cases that achieve 100% RPS both with and without LNG and cases that evaluate maximum DER adoption rules. All cases with LNG will assume that LNG will be a 20 year term, ending in 2040, and all applicable costs will be depreciated over a 20 year period.

Stakeholders Submitting Input on this Topic

Consumer Advocate
Blue Planet Foundation
Hawai‘i Gas

Hawai‘i Solar Energy Association (HSEA)
Paniolo Power
Sierra Club
SunPower
Ulupono Initiative

Status of this Topic

We will address all remaining issues in our Updated PSIPs.

Fossil Generation Upgrades

Summary Description of this Topic

- Request additional information to better understand the final cost and performance characteristics of fossil generation upgrades (such as, how the units previously behaved, what the modified units are now capable of, and how the performance and savings of the modified generators might compare to new generating units).

Our Action Regarding this Topic

We will document the cost of generation and the benefits the upgrades will yield; and quantify the incremental value of the upgrades compared to the next best alternative (that is, replacement generation).

Stakeholders Submitting Input on this Topic

Consumer Advocate
Department of Business, Economic Development, and Tourism (DBEDT)
Hawai‘i Gas
Paniolo Power
Sierra Club
SunEdison (First Wind)
SunPower
Tawhiri

Status of this Topic

We will address this topic in our Updated PSIPs.

Party Input

Summary Description of this Topic

- Assurance that Party input will be considered and integrated in alternative plans and the Preferred Plan.

Our Action Regarding this Topic

We will describe, in detail, how we incorporated party input into our analysis, and continue to solicit further Party input at our proposed February technical conference and through our FTP server.

Stakeholders Submitting Input on this Topic

Consumer Advocate
Department of Business, Economic Development, and Tourism (DBEDT)
Hawaiʻi Solar Energy Association (HSEA)
Life of the Land (LOL)
Tawhiri

Status of this Topic

We will address this topic in our Updated PSIPs.

Energy Efficiency and Electric Transport

Summary Description of this Topic

- Assurance of adequate discussion of how energy efficiency will help with grid issues. In addition, the CA wants the Companies to use recently published energy efficiency study for potentially incorporating energy efficiency measures.
- Want the Companies to encourage the adoption of electric transport.

Our Action Regarding this Topic

We will document energy efficiency and electric transport forecasts and how we optimized both in our Updated PSIPs.

Stakeholders Submitting Input on this Topic

Consumer Advocate
Department of Business, Economic Development, and Tourism (DBEDT)
Blue Planet Foundation
Hawaiʻi Solar Energy Association (HSEA)
Renewable Energy Action Coalition of Hawaiʻi (REACH)

Status of this Topic

We will address this topic in our Updated PSIPs.

Inter-Island Transmission

Summary Description of this Topic

- Address the impact that inter-island transmission will have on the reliability of the O‘ahu, Maui, and Hawai‘i Island power grids.
- Address the prospect of a forced cable outage, which then affects reserve requirements and reliability.

Our Action Regarding this Topic

We will document the cost of inter-island transmission via an undersea cable, and how that cost can potentially be offset by almost double the wind capacity of wind on Maui and Hawai‘i Island. We will also discuss potential two-way island benefits (such as reliability, grid security, and power sharing).

Stakeholders Submitting Input on this Topic

Consumer Advocate
County of Maui (CoM)
Department of Business, Economic Development, and Tourism (DBEDT)
Paniolo Power
Ulupono Initiative

Status of this Topic

We will address this topic in our Updated PSIPs.

C. Analytical Models

We are employing a number of analytical models to develop our Updated PSIPs. The Hawaiian Electric System Planning team, our Transmission Planning team, and several consultants process numerous individual and overlapping model runs using these tools. Together, we are performing a thorough, exhaustive analysis to develop a series of alternative plans. Then, from those plans, we are developing Preferred Plans for each operating utility to provide reasonable cost, reliable energy to our customers.

These modeling tools and the team running the tool include:

- Siemens PTI PSS®E for System Security Analysis: Hawaiian Electric Transmission Planning Division
- P-MONTH Modeling Analysis Methods: Hawaiian Electric System Planning Department
- Adaptive Planning for Production Simulation: Black and Veatch
- DG-PV Adoption Model: Boston Consulting Group
- Customer Energy Storage System Adoption Model: Boston Consulting Group
- Grid Defection Model: Boston Consulting Group
- PowerSimm Planner: Ascend Analytics
- Long-Term Case Development and RESOLVE: Energy and Environmental Economics (E3)
- PLEXOS® for Power Systems: Energy Exemplar
- Financial Forecast and Rate Impact Model: PA Consulting

SIEMENS PTI PSS®E FOR SYSTEM SECURITY ANALYSIS

Hawaiian Electric Company's Transmission Planning Division uses the Siemens PSSE (Version 33) Power-Flow and Transient Stability program for transmission grid modeling and for system security analysis. This program is one of three most commonly used grid simulation programs in United States utilities. The program supports the IEEE (Institute of Electric and Electronic Engineer) generic models for generators and inverters. When available, custom models can preclude generic models.

PSSE is high-performance transmission planning software that has supported the power community with meticulous and comprehensive modeling capabilities for more than 40 years. The probabilistic analyses and advanced dynamics modeling capabilities included in PSSE provide transmission planning and operations engineers a broad range of methodologies for use in the design and operation of reliable networks. PSSE is used for power system transmission analysis in over 115 countries worldwide.

The program has two distinct program models: (1) power flow to represent steady state conditions and (2) stability to represent transients caused by faults and rapid changes in generation. The transient conditions are modeled to about 10 seconds post-event to determine whether the system will stabilize or fail.

After major system disturbances, we use this program to verify the system events as well as to verify the modeling assumptions.

Input to this program includes impedances for all the transmission lines, transformers, and capacitors; detailed information of the electrical characteristics of all generators and inverters (including PV panels and wind turbines); and energy storage devices (such as batteries). The model includes relays for fault clearing and under-frequency load shedding (UFLS).

Electric Power Systems used the PSSE model to conduct its robust and detailed system security studies because the model allows rapid and consistent sharing of data.

P-MONTH MODELING ANALYSIS METHODS

The Hawaiian Electric System Planning Department uses the P-Month hourly production simulation model to perform analyses for developing alternative plans for the updated PSIPs.

The P-Month modeling tool includes these characteristics:

- Preservation of the chronological sequence of hourly loads in simulating system operations.
- Use of realistic unit commitment and economic dispatch procedures, recognizing generating unit minimum up and down times, ramp rates, and hourly spinning reserve requirements.
- Probabilistic representation of random force outages of generating units.
- Monte Carlo simulation options for generating unit forced outage representation.
- Nodal, company, and system hourly marginal cost and average cost calculations.
- Modeling of both fixed energy and economy transactions.
- Run-of-river and hydro resource modeling.
- Cost-based energy storage optimization.
- Representation of fuel contracts and fuel contract inventory tracking.
- Transmission-based multi-area and multi-company modeling.
- Bidding strategies plus cost and revenue calculations for generating companies.

The P-Month model can simulate detailed hourly electric utility operations for period of one month up to thirty years or more. These hour-by-hour simulations enable us to:

- Study the integration of advanced or renewable power generating technologies into our electric power grid.
- Study the operational impacts of weather-sensitive generating technologies—in other words, variable renewable generation.
- Evaluate energy storage technologies.
- Determine load following and spinning reserve capabilities.
- Investigate load control strategies.

The Companies used computer models for the PSIP analyses. Production costs of the operating the system is simulated using the P-Month hourly production simulation model. The model is populated with unit data to characterize the resources operating on the system at all hours so that the performance and cost of the system can be evaluated for various future cases. The data from the hourly production simulation model is processed using other internally developed tools to evaluate the results of the simulations.

P-MONTH Hourly Production Simulation Model

Thermal Generation Modeling

The model, P-MONTH, is an hourly production simulation program supplied by the P Plus Corporation (PPC). This model simulates the chronological, hour-by-hour operation of the generation system by dispatching (mathematically allocating) the forecasted hourly load among the generating units in operation. Unit commitment and dispatch levels are based on fuel cost, transmission loss (or "penalty") factors, and transmission system requirements. The load is dispatched by the model such that the overall fuel expense of the system is minimized (that is, "economic dispatch") within the constraints of the system. The model calculates the fuel consumed using the unit dispatch described above, based on the load carried by each unit and the unit's efficiency characteristics. The total fuel consumed is the summation of each unit's hourly fuel consumption.

Variable Generation Modeling

The model calculates the energy produced by renewable resources and other variables using an 8760 hourly profile. This profile is constructed based on historical observed output from in service variable generation or from solar irradiance profiles and measured wind potential for future variable generation. Generation that is produced according to this hourly profile that cannot be accommodated on the system in any one hour will be curtailed per the curtailment order. The curtailment order follows a last in, first out rule whereby the last installed variable renewable resource will be curtailed first, that is, reverse chronological order for resources designated as being able to be controlled.

Unit Forced Outage Modeling

The production simulation model can be used by applying one of two techniques: probabilistic or Monte Carlo. Using the probabilistic technique, the model will assume generating units are available to operate (when they are not on overhaul) at some given load that is determined by their normal top load rating and forced outage rate. By this methodology, the units will nearly always be available at a derated capacity that has been reduced to account for the forced outage rate.

P-MONTH has a Monte Carlo Simulation option in which random draws are used to create multiple cases (iterations) to model the effect of random forced outages of generating units. Each case is simulated individually; the averages of the results for all the cases represent the expected system results. This Option provides the most accurate simulation of the power system operations if sufficient number of cases are used. However, the computer run time can be long if many cases are run. The number of cases needed to establish a certain level of confidence in the results depends on the objectives of the user and the size of the system. Normally, the system production cost will converge sufficiently between 20 and 30 iterations.

Using the Monte Carlo, or deterministic, technique, forced outages for generating units are treated as random, discrete outages in one week increments. The model will randomly take a generating unit out of service (during periods when it is available) up to a total forced outage time of 5%. By this methodology, the unit can operate at normal top load for 95% of the time when it is not on overhaul but will not be able to operate (that is, will have a zero output) for 5% of the time when it is not on overhaul. For the PSIP, the modeling will use the Monte Carlo methodology to capture the forced outages of all thermal units.

Demand Response Modeling

Demand response programs were modeled to provide several potential benefits including capacity deferral and regulating reserve. Programs that provide capacity were included in the capacity planning criteria analysis assessment. Programs that provide regulating reserve ancillary services were included in the modeling.

Energy Storage Modeling

The benefits of energy storage for system contingencies are captured in the system security modeling. Regulating reserves were provided by a combination of energy storage and thermal generation. Load shifting was modeled as a scheduled energy storage resource. The round-trip efficiency was accounted for in the charging of this resource. The charging schedule was optimized to coincide with the hours in which curtailment occurred or the profile of PV energy during the day to minimize day time curtailment. The discharging schedule coincided with the evening peak.

System Security Requirements

The system security requirements were met by including the regulating and contingency reserve capabilities of demand response, energy storage, and thermal generation in the modeling. The system security requirements depend on the levels of PV and wind on the system. The regulating reserve requirements were changed hourly in the model to reflect the dynamic changes in levels of PV and wind throughout the day. Curtailed energy from controllable PV and future wind resources contributed to meeting the regulating reserve requirement. The contingency reserve requirements for O‘ahu were changed annually to reflect the largest unit contingency on the system.

Sub-Hourly Model

The P-Month model is an hourly chronological model. Sub-hourly modeling cannot be done using this model. The Companies developed a limited sub-hourly model to assess any value that the hourly model was not able to capture compared to the modeling sub-hourly when batteries, and other resources that operate like batteries, are on the system.

Key Model Inputs

In addition to the system changes described in the Base Plan, there are several key assumptions that are required for modeling:

- Energy and hourly load to be served by firm and non-firm generating units
- Load carrying capability of each firm generating unit
- Unit operating characteristics (such as minimum up time, minimum down time, operating range, ramp rate)
- Efficiency characteristics of each firm generating unit
- Variable O&M costs
- Operating constraints such as must-run units or minimum energy purchases from purchased power producers
- Overhaul maintenance schedules for the generating units
- Estimated forced outage rates and maintenance outage rates
- Online (spinning) reserve requirements
- Demand response and energy storage resources
- Fuel price forecasts for fuels used by generating units

Methodology for Post-Processing of Production Simulation Results

Key Outputs

Some of the key outputs from the model are as follows:

- Generation produced by each firm generation unit
- Generation accepted into the system by non-firm generating units
- Excess energy not accepted into the system (curtailed energy)
- Fuel consumption and fuel costs
- Variable and fixed O&M costs
- Start-up costs

Post-Processing

The outputs from the model are post-processed using Excel to incorporate the following:

- Capital costs for new generating units, renewable and energy storage resources, allocated based on capital expenditure profiles
- Capital costs for utility projects such as fuel conversions or the retirement of existing utility generating units
- Payments to non-dispatchable Independent Power Producers (IPP) for purchased power, including Feed in Tariff projects
- Fixed O&M for future energy storage resources

All costs are post-processed into annual and total dollars to be used in the Financial Model. All annual, total, and present value (2015$) revenue requirements are also post-processed for use in evaluating the different plans but are not meant to be the "all-in costs" that the Financial Model will be doing. Revenue requirements are characterized as utility and IPP. Utility revenue requirements are categorized into fuel, fixed O&M, variable O&M, and capital. IPP revenue requirements are categorized into capacity and energy payments. Using the revenue requirements from post-processing, plans can be analyzed according to several key metrics.

Key Metrics

The key metrics analyzed through post processing of the model data are as follows:

- Differential accumulated present value of annual revenue requirements
- Differential rate impact
- Monthly bill impact
- Total system curtailment
- RPS
- Gas consumption
- Utility CO_2 emissions
- Annual generation mix
- Daily generation mix by hour

Lana‘i & Moloka‘i Modeling

The model used in the analysis for Lana‘i and Moloka‘i is an Excel based model focusing on meeting the total sales (energy) forecasted for each year. In this way the amount of energy produced from each resource was assumed to be taken regardless of any profiles. This simplified model shows results that are directionally correct.

The model calculations are broken up into three pieces: existing power purchase agreements, future renewable resources, and utility generation. First, it is assumed that the utility generation will provide a minimum amount of generation for system reliability. Second, the existing power purchase agreements fill in additional energy based on historical purchases. Lastly, future resources can be added to get as close to the total sales as possible. If the total energy provided by the three pieces is less than forecasted sales for a particular year, the utility generation will increase to make up the difference. If the total energy is greater than forecasted sales then the excess is curtailed from newly added resources.

The model will track all costs associated with fuel expense, O&M, capital, and power purchased payments to give annual revenue requirements and total net present value (NPV) consistent with the analysis for the other islands. Similarly, the model will also calculate the RPS percent for each year of the plan.

The utility generation component allows for different fuels to be assigned to the units as well as splitting the fuel types as necessary. Fuel usage and associated costs are calculated for each year.

Future renewable resources are identified by the year of installation as well as ownership (for example, utility or IPP). Resource ownership determines the capital expenditures patterns. Either a levelized profile or a declining profile to match company revenue requirements is used in the analysis. Costs for O&M and applicable fuel costs for each year are calculated for the new resources.

ADAPTIVE PLANNING FOR PRODUCTION SIMULATION

Black & Veatch is applying its Adaptive Planning (AP) for Production Simulation to support the PSIP. AP for Production Simulation provides a framework for modeling complex systems, exploring options (impacts of constraints), and comparing such options across varying metrics. Key metrics or outcomes associated with this analysis include costs, degree of renewable penetration (both capacity and energy served), utilization of demand response and distributed energy resources, avoided costs associated with demand response, and metrics associated with generation-related grid security.

The AP for Production Simulation model incorporates Demand Response (DR), Distributed Energy Resources (DER), and renewable integration into its production runs.

AP for Production Simulation is delivered through Black & Veatch's ASSET360™ platform, possessing state-of-the-art ability to evaluate technical asset performance, commitment, dispatch, and operations problems. ASSET360™ and AP for Production Simulation features cloud-based analytics and math engines and provides the ability to construct and explore wide range of cases and sensitivities. This capability was extended in concert with Hawaiian Electric to also manage and evaluate interaction and valuing of DR products and program portfolios. This enables AP for Production Simulation to model and compare very granular energy and grid services protocols and to identify optimal allocation of combined physical plus DR resources to provide a full range of services. ASSET360™ builds upon over 20 years of complex modeling and simulation tools developed and implemented by Black & Veatch to evaluate alternative technology, fuel, maintenance, compliance, and operational strategies and develop actionable and implementable plans.

AP for Production Simulation applies a sub-hourly analysis to model combinations of conventional power production and grid resources, variability of non-firm resource supply, storage, and energy and grid services protocols, all to identify the optimal allocation of combined physical plus DR resources to provide a full range of services. Sub-hourly analysis is required to fully understand and model impacts of variability of wind and solar, and to accurately assess the need for grid services and fit of DR program portfolio in concert with physical assets to support those needs.

Black & Veatch possesses deep domain expertise in the technologies deployed – from design, operations, and reliability perspectives – as well as deep domain expertise in complex simulation. This combination provides critical thinking and credibility needed in addressing very complex and costly investment decisions across PSIP areas of interest. Given the desire and need for massive transformation, the underlying model must be very technically robust to assure that all transformative steps are both rational and fully understood. Key aspects that can be specifically addressed include technology selection and implementation, plant refurbish and upgrades, retirements, DER build out, and participation and structure of DR programs.

Clearly, Black & Veatch capabilities and reputation are critical for both credibility of the process and model as well as credibility of the results, given that the interactions between conventional power production, renewable resources, storage, and customers are very complex, and given that Hawaiʻi is clearly on the cutting edge of such strategy development. Black & Veatch possesses the ability to leverage proven analytics framework within the context of the Hawaiian Electric PSIP, to provide high-level of modeling expertise to build and refine PSIP strategies or cases, and the ability to help define and manage complex processes needed to align asset portfolio, security requirements, DER uptake assumptions, and DR portfolio implementation and utilization. These capabilities are complementary to the larger PSIP team and are foundational to PSIP team's ability to deliver critical thinking and key results.

Exploration of options and collaboration between Hawaiian Electric, Black & Veatch, and other consultants is also quite important to achieving quality results. Processes implemented for coordination across the modeling teams are, by necessity, complex and iterative; Black & Veatch possesses the fundamental capabilities needed to support these important activities. The ability of AP for Production Simulation to leverage the cloud is also particularly valuable for PSIP where exploration across decision dimensions is needed. For example, automated processes can be leveraged to explore the solution space (that is, timing and volumes of DER resources, timing and volumes of utility-scale renewable and energy storage resources). This enables the PSIP team to see and illustrate value and strength of strategies and sensitivity of strategies to key underlying assumptions.

Configuration Methodology

AP for Production Simulation manages the overall calculation and cost accounting process. PSIP-specific requirements are directly addressed by configuring the solution.

Thermal Generation

Firm thermal generation resources are modeled as having the ability to meet demand, up and down regulation, contingency, and frequency response (modeled as system inertia requirements based on system state). Assets are committed based on the combined minimum load operating, minimum load fuel, startup time, and associated startup costs. These assets are dispatched by AP for Production Simulation's optimizer to achieve the lowest possible fuel and variable operating costs based on a given set of constraints.

Data required to support the commitment and dispatch of these resources include the following:

- Installation and deactivation and retirement dates
- Fuel, variable operating, startup, and startup fuel costs or generation-related PPA cost
- Fuel contract and supply constraints
- Fuel switch dates and fuel switch capital costs
- Heat rate curve and minimum and maximum loads
- Ramp rate, hot and cold start time, minimum up and down time limitations
- Scheduled outages or rate, forced outage rate
- Kinetic energy (as proxy for ability to provide inertial response)
- Operating limitations to meet transmission system security requirements
- PPA obligations
- Unit operating constraints because of emission regulations or work shift requirements.

Additional information required to characterize the generating cost of each resource includes capital and fixed operating costs, including transmission-related costs.

Variable Generation

Future variable generation resources are modeled as having the ability to provide demand and down regulation via curtailment. Energy produced by the variable resources is calculated using an hourly or sub-hourly profile constructed from historical data from in-service variable generation or from solar irradiance profiles and measured wind potential for future variable generation. Generation that is produced according to this profile but cannot be accommodated on the system will be curtailed per a specified curtailment order.

Data required to model the generation available from these resources and associated costs includes the following:

- Hourly or sub-hourly generation profile
- Ability to be curtailed and curtailment order of the asset including curtailment costs
- Energy contract costs for non-utility owned resources
- Capital and fixed operating costs, including transmission-related costs

Central Energy Storage

Utility-scale energy storage is applied as a resource to supply capacity, regulation, contingency, and other ancillary services associated with frequency response. Energy storage added to supply capacity, regulation, or contingency is modeled via the dispatch model. Energy storage added to manage frequency response supplements the commitment of firm resources and other resources that also provide frequency response.

Data required to model the usage of these resources and associated costs includes the following:

- Size, capacity, and efficiency
- Usage schedules or rules
- Operating restrictions

Distributed Energy Resources

Distributed energy such as rooftop photovoltaics or customer-owned batteries is integrated into AP for Production Simulation in a method very similar to the treatment of utility storage and utility PV. Distributed energy resource generation is developed following an hourly profile and is treated as a reduction in sales and demand. Some distributed generation resources are able to be curtailed and this functionality is also modeled.

Data required to model the generation available from distributed energy resources and associated costs includes the following:

- Hourly generation profile
- Ability to be curtailed and curtailment order of the resources including curtailment costs
- Contract costs (for example, Feed-in Tariffs-FIT)
- Battery size, capacity, and efficiency
- Battery usage schedules or rules

Demand Response

Demand response can be evaluated in two ways.

A known DR portfolio are factored into AP for Production Simulation as a change in overall demand curve as influenced by time-of-day pricing and an ability to provide ancillary services (up and down regulation, contingency, and frequency response). Data required includes the following:

- Hourly load modification projections by product
- Hourly ancillary services projections
- Program fixed and incentive costs

The available products in an unknown DR portfolio are evaluated individually and in combination to identify the optimum portfolio mix. In this situation, products are fit together to either afford ability to substitute for physical resources; or provide economically superior response mechanism to address load dynamics or unexpected contingency events. Information required for each of the products includes magnitude of service, cost of DR to provide each service, attributes of each service, and identified opportunities for combinations of services:

- Purpose (capacity, peak shaving, ramp avoidance)
- Availability (MW, time)
- Characteristics (ramp rate, response speed, accuracy)
- Response after curtailment (snap back MW and duration)
- Limitations (event duration, frequency)
- Costs to provide the service (fixed, per event, per kW called)

Finally, the value of individual products year to year can be significantly different as the system is in a state of flux with the addition and retirement of utility-scale resources, the continuous addition of consumer batteries, and evolving loads (electric vehicle loads for example) all contributing to make each year’s demand response value proposition unique. Thus, the makeup of the DR portfolio can be expected to vary over time.

System Security

System security requirements for primary frequency response serve as the basis for DR analysis. Given the interest in identifying if and when DR products could substitute for physical resources in this context (for example, FFR), the ability to understand implications of the security protocols on service requirements and degree of fit for DR versus conventional resources is a key issue. To this end, Black & Veatch incorporated a regression model based on inertia and kinetic energy from electric generators to better relate needs to optional portfolio and service combinations into the AP tool. The resulting regression was incorporated as a commitment requirement.

Regression equations were developed for O‘ahu to understand the additional response requirements for 2018 forward. The regression simulated Hawaiian Electric Transmission Planning results for the response requirements based on the system state each hour. Twelve-cycle data was used in the regression analysis. The regression model enabled the overall requirements to be met either via application of physical resources or via combination of physical resources and DR products.

The following are typical of types of assumptions that support the security analysis:

- The largest contingency was based on largest single generating unit trip (while AES is operational, 180 MW) with a concurrent 59.3 Hz Legacy PV trip (55 MW).
- Allowable load shed for 2016 and 2017 based on present day reliability.
- When the Contingency Energy Storage is in service, allowable load shed is eliminated.
- Fast Frequency Response modeled as step MW injection before a minus 12 cycle time delay from time of disturbance.
- MW requirement is based on reliability, which is driven by the contingency and the load shed scheme.

Time Slice Model within AP for Production Simulation

At the heart of AP for Production Simulation is a direct solution engine within a time slice model that enables a direct aggregate match of resources to demand and security requirements. Within AP for Production Simulation, each time slice affords the opportunity to accomplish the following:

- Introduce new resources, retire resources, or change asset characteristics (simulate planned and forced outages, fuel switch, reduce minimum load).
- Introduce DR products (quantity by product, maximum calls, maximum duration).
- Incorporate assumptions for wind and solar variability based on perturbations of historical wind and solar patterns.
- Incorporate rules for utilizing distributed generation as a must-take and/or curtailable resource.
- Commit resources and schedule DR products based on asset availability, grid security, policy constraints, and economics.
- Dispatch resources or call DR products based on grid security protocols and economics including use of demand response and energy storage to address ramping or smoothing, and forced outages of committed resources.
- Identify boundary conditions (from time slice to time slice) that serve as the basis for evaluating the next time slice; certain actions, such as starting a thermal generator within a particular time slice, would require forward commitment across time slices.

The simulation engine works in conjunction with the commitment and dispatch algorithms to evaluate the situation in the current period and translate this information to subsequent affected time slices. Each time slice considers (takes as input) the following for each power source:

- Status (available, scheduled outage, forced outage, retired).
- Operating efficiency and minimum load.
- Maximum load (as limited by solar or wind penetration forecast, as applicable).
- Fuel characteristics and costs (if applicable).
- Startup costs and fuel requirements (if applicable).
- Variable operating costs or power purchase agreement costs.
- Ramp rates, minimum downtime, and minimum uptime.
- Fixed operating and capital costs.

Each time slice also considers demand adjusted for demand response load shaping programs. With this information, the time slice model determines the following for each power source:

- Status applicable to next time slice
- Generation
- Contribution to regulating requirements and other grid services
- Consumable requirements
- Operating costs

Commitment and Dispatch Methodology

AP for Production Simulation addresses commitment requirements on an hourly basis and dispatch on either hourly or sub-hourly increments. For example, five-minute increments are applied for assessing a regulating reserves DR program where the dynamics of wind and solar loading are being matched with DR or firm asset services for regulation.

When determining commitment (units that are online), the model endeavors to meet both demand (incorporating load-shift demand response) and grid security requirements. It will start up or shut down generating resources as needed to meet these requirements. It prioritizes the resources online (1) to include units required to support system security, (2) to meet goals such as maximizing renewable resource use, and (3) to meet the requirements of power purchase agreements.

Once commitment is set, the model considers dispatch. If dispatch needs to increase to meet demand, the model first considers preferential dispatch targets such as eliminating curtailment of renewable resources. Next, regulating reserve batteries, if available, are dispatched to their target. Finally, load is increased at dispatchable units based on economics. If dispatch needs to decrease to match demand, dispatchable units are economically backed down, regulating reserve batteries are charged to maximum capacity to minimize curtailment and, as last resort, non-firm renewable resources are curtailed.

Demand Response Methodology

Specific modeling techniques to evaluate the range of services provided by DR were developed based on the characteristics of each service. Services are segmented into two categories: fast (defined as a service to address a transient issue), and slow (defined as a service to manage system demand and supply equilibrium). Fast services are characterized by defined constraints (for example, required regulating reserves), modeling of security requirement proxies (for example, use of kinetic energy as proxy for addressing fast frequency response requirements), and inclusion of incremental costs (for example, application of battery to supply contingency requirements). DR products are then evaluated for their ability to compete against other resources to provide each service.

When combining the potential of individual DR products into a portfolio, it must be recognized that each end use device can only provide one service at a time. For example, a water heater cannot provide both fast frequency response and regulating reserve at the same time as once it has been turned off to provide one service, there is no potential available for any other service. As such the demand response potential for each demand response product must be managed to prevent double allocation of end use devices.

AP for Production Simulation maps end use devices to demand response products to ensure no double allocation. The demand response end use allocation is based on the best value derived from the end use device. Since the demand response potential is dynamic by hour (air conditioner load is higher in the summer and peaks during midday) and the needs of the generation and transmission system are also dynamic by hour, demand response potential is allocated for each hour. The allocation is complex as some system constraints are dynamic. For example, the system security requirement that sets the fast frequency response need is based on the unit commitment, which is determined by the allocation of demand response end use devices for regulating reserves and load shifting. Given the finite demand response potential, the optimal allocation often requires the layering of the constraints such that all constraints are satisfied and the demand response potential is not over allocated.

Order and priority between underlying resources are managed as follows:

1. Pricing products shift load to desirable times and thus support capacity needs.
2. Fast frequency response (FFR) is given next priority for potential. It meets both fast frequency response and can also be used to provide an equivalent to contingency in combination with NSAR.
3. NSAR back-stops FFR so that, combined, the two products can provide an equivalent to contingency. Dedicated NSAR can reduce contingency battery size when paired with FFR.
4. Regulating reserve meets up-regulation.
5. Aggregated DR calls are checked against aggregated limits (number of calls per year, length of call) to ensure usage is within limits.
6. Products that meet specific needs other than those listed above, such as PV-Curtailment and Minimum Load, were not shown, in prior evaluations, to be cost-effective. Thus, these products are evaluated external to the simulation process to quantify their contribution to the generation system and can be incorporated into the simulation process when cost-effective.

The first bullet above requires further explanation to fully describe the evaluation process. The load shift is evaluated as an outer loop to the simulation model in order to optimize between pricing and incentive products.

- Potential associated with pricing products is allocated in a manner consistent with the anticipated price signal flexibility. Potential associated with products under a tiered rate schedule is allocated approximately as required by the generation system, but is constant for each hour within a tier. Potential associated with pricing products set via a forward-looking, hourly pricing scheme is tailored hour-by-hour and therefore more closely matches the requirement of the generation system. The load shift is MWh neutral on a daily basis; the increase and decrease each day does not change the overall demand associated with that day.
- Tradeoffs between pricing products and incentive programs are evaluated for distinct levels of pricing products taken (0%, 50%, 100%). When less than 100% of the pricing product is used for load shift, the remainder of the end product's potential is made available (where there is overlap) for FFR, NSAR, and so on.
- Each level of participation is compared for each day; the case with the lowest generation cost defines the percent of pricing product taken for that day.

The pricing products may reduce or postpone new generation as pricing programs shift loads and thereby reduce the annual peak. This reduces the need for new units to meet the reserve margin requirements.

Sub-Hourly Model

Traditional hourly modeling does not expose the operational transients that must be managed during real-time operation of the electric grid. Hence, traditional hourly modeling also does not expose potential value (economic and risk mitigation value, for example) that one set of resources may have over another set of resources, as all transients are softened. Sub-hourly modeling will expose some of this value to support the optimum resource selection that does not violate policy considerations (risk tolerance, renewable goals, budget constraints, fuel diversity)

Similar to an hourly modeling approach, the sub-hourly model calculates both commitment (which units are generating power) and dispatch (MW contributed by each asset to achieve the target demand) but now at a sub-hourly time step. Maximum daily rate of change will be greater and ramp rate constraints will be hit more often, thereby potentially changing the economic outcome of the simulation as compared to the hourly model.

The sub-hourly model (five minute time step) performs a constrained optimization for asset dispatch against a sub-hourly desired load. The resources considered include generation (dispatchable and non-dispatchable), demand response, and energy storage. Each asset will have two primary states: available or unavailable. Each unavailable state may have sub-states—for example, scheduled versus unscheduled outage. There are also system constraints that must be met. These include:

- Spinning reserve requirements (incorporating energy storage and demand response options)
- Grid stability requirements, either must-run units or verification that adequate inertia is present on the system given system conditions
- Policy constraints (power quality, reliability targets, risk tolerance)

The sub-hourly model will change the state of each asset to optimize the economics within the bounds of the model constraints. Accounting routines will keep track of asset performance ($, MWh, number of starts) and system performance (unserved load, curtailed generation, $, MWh).

The modeling approach defined above is ideally suited to evaluating, comparing, and contrasting differing strategies regarding the mix of fossil generation, utility renewables versus energy storage, distributed generation versus energy storage, and demand response options. Based on the supply options provided, the model will determine the low-cost means for meeting the required load within constraints. These constraints can be modified to evaluate other policy considerations (such as greater renewable penetration).

Model Outputs and Visualization Tools

AP for Production Simulation output is generally organized into views of differing granularity according to the following:

- *Periodic Values:* this can be period to period (five-minute, hourly, daily, or annual) and will consist of period inputs (assets available, state, demand), production factors (individual asset production and/or utilization in support of grid services), consumables (fuel, chemicals), and other variable O&M costs.
- *Average Day:* this view aggregates and averages all period values into a single day "view" by year. This allows one to see and understand system behavior, unit participation and ramping, and provision of services during peak and off-peak periods.
- *Specific Day:* similar to Average day, this view provides same outputs but for a specific day or range of days. This allows one to see variability in use of system resources from day-to-day, year-to-year. This view is particularly valuable in understanding variability in the value of grid services and optimizing DR portfolio.
- *Aggregations by Resource Type:* all views above are available either by individual asset or DR program or aggregated by type of asset. This provides ability to see how different asset classes are utilized in matching demand or providing grid services.
- *Comparisons:* comparison views are applied against two cases to identify differences in outcomes, year-to-year or period-to-period.
- *Avoided Costs:* avoided cost views are generated by mathematically "subtracting" an underlying base or reference case from the subject case. In particular, grid service values (or value of DR program) are based on mathematically assessing differential system costs against differential resources available to provide the grid services.

DG-PV ADOPTION MODEL

BCG developed the proprietary DG-PV Adoption Model to forecast and optimize the adoption of customer-sited energy resources. The model primarily determines the quantity and total power supply of DG-PV (with and without storage), the given retail or export rate, when this adoption would occur. BCG has applied this model throughout the United States, Europe, and Australia with high levels of success. The model helps develop perspectives from a customer-centric approach regarding compensation levels, and resulting amounts and timing of customer-sited energy resources.

The model was used to forecast future quantities of grid-supply up to the cap, self-supply quantities, and potential future DG-PV combined with the possibility of the adoption of customer-sited storage. The model was also used to evaluate the potential impact of grid defection.

The DG-PV Adoption Model examines the relationship between customer economics and technology adoption (net present value (NPV), internal rate of return (IRR), and payback time for adopting DG-PV with or without a storage system). The model optimizes the distributed energy resource system configuration to yield the highest NPV given technology costs, appropriate investment tax credits, and retail or time-of-use (TOU) and export rates. The model then applies optimum results to a regression-based relationship of previous DG-PV adoption to determine the number of future installs and the total sum of energy provided. This approach allows for distributed energy values to be optimized and forecasted based on customer logic and economics, then integrated into the system resource mix as an optimized resource. The model can also integrate explicit integration costs to fine-tune the customer adoption levels as necessary.

BCG is a global consultancy with 84 offices across 46 countries of the world with over 50 years of experience in the energy sector. BCG has successfully completed over 3,400 engagements across the energy value chain including over 1,400 engagements involving renewable and distributed energy resources.

BCG has been involved in the PSIP process since 2014 and is intimately familiar with the exceptional complexities surrounding Hawai‘i’s energy markets. For the Updated PSIPs, BCG is performing customer economic and adoption modeling of DG-PV and energy storage systems to determine how to best forecast and optimize these components. This wealth of experience, coupled with local understanding, positions BCG as being uniquely suited to support the Companies craft a solution that optimizes DERs in Hawai‘i’s energy future.

BCG worked with the Companies as well as Black &Veatch to develop the following assumptions that are being used to develop DG-PV forecasts:

- Progression of technology costs for DG-PV technology from 2016–2045.
- Progression of technology costs for customer storage technology from 2016–2045.
- Future value of storage based on the Black & Veatch Adaptive Planning for Production Simulation model.
- Historical relationships for Hawaiʻi, by island, between net present value (NPV), internal rate of return (IRR), and payback time and levels of customer adoption for DG-PV.
- PV irradiance profiles for each island.
- Current load and consumption profiles for each rate schedule.
- Current and addressable populations for DG-PV and customer storage.

The model then provides as outputs:

- Optimum NPV, IRR, and payback period for a given load profile, system configuration, rate schedule, and build year.
- Overall number of installed DG-PV systems and energy capacity through 2045 based on NPV and payback periods.

CUSTOMER ENERGY STORAGE SYSTEM ADOPTION MODEL

BCG's proprietary Customer Energy Storage System Adoption Model forecasts customer installations of storage. The model first calculates economics (including payback time) of customer-sited storage installed in a given year based on the total value of storage that it provides. Based on this payback, the model forecasts the percent of eligible customers that adopt storage systems. Eligible customers are assumed to be those who have yet to install a storage system. The correlation of payback to percent of eligible customers is based on the historical correlation of payback time for a DG-PV system and the percent of eligible customers that adopted DG-PV. Given a similar economic profile, a similar percent of customers will adopt a storage system as have adopted historical DG-PV, mainly because the two investments are similar.

The Model uses the following as inputs:

- Customer storage technology cost forecasts through 2045 (including Li-Ion battery, balance-of-system (BOS), installation, and annual O&M costs).
- Customer storage technology performance forecasts through 2045 (including energy capacity, power capacity, round-trip efficiency, and equipment life expectancy).
- The value of storage forecasts through 2045 based on Black & Veatch's model, including the value of various grid services that can be fulfilled by storage systems (including day-ahead load shift and time of use, fast frequency response, and regulating reserve), while ensuring no double counting. The value is based on the avoided cost to the electric system for the grid services that the storage systems provide (as calculated by the Adaptive Planning for Production Simulation model).
- Historical payback time of DG-PV.

Using these inputs, the storage system adoption model first calculates customer economics for installing storage systems in a given year, and then forecasts customer adoption of storage systems based on the customer economics. The model then outputs the customer storage system adoption forecasts through 2045 (based on system-optimized compensation at avoided cost).

This modeling tool is suitable to calculate the system-optimal level of standalone storage systems to include in the PSIP planning process for two key reasons:

- It forecasts the amount of cost-effective standalone storage systems that could provide grid services.
- It forecasts customers adopting distributed energy resources by using actual historical correlations between customer payback time and adoption rate.

These forecasts are then used as input to the DR potential forecast and DR avoided cost modeling, which in turn generates DR amounts and load shapes that are included in overall system planning.

GRID DEFECTION MODEL

The Commission has raised the issue of grid defection or the possibility of customers or customer groups leaving the grid thus shifting fixed cost coverage to the remaining customers. To address these concerns and better understand the potential impact of such an occurrence, the companies are developing a methodology to analyze the issue (Figure C-27).

There was not sufficient time to incorporate this analysis into this initial iteration for the PSIP Update Interim Status Report, but will be incorporated by the April 1 filing date.

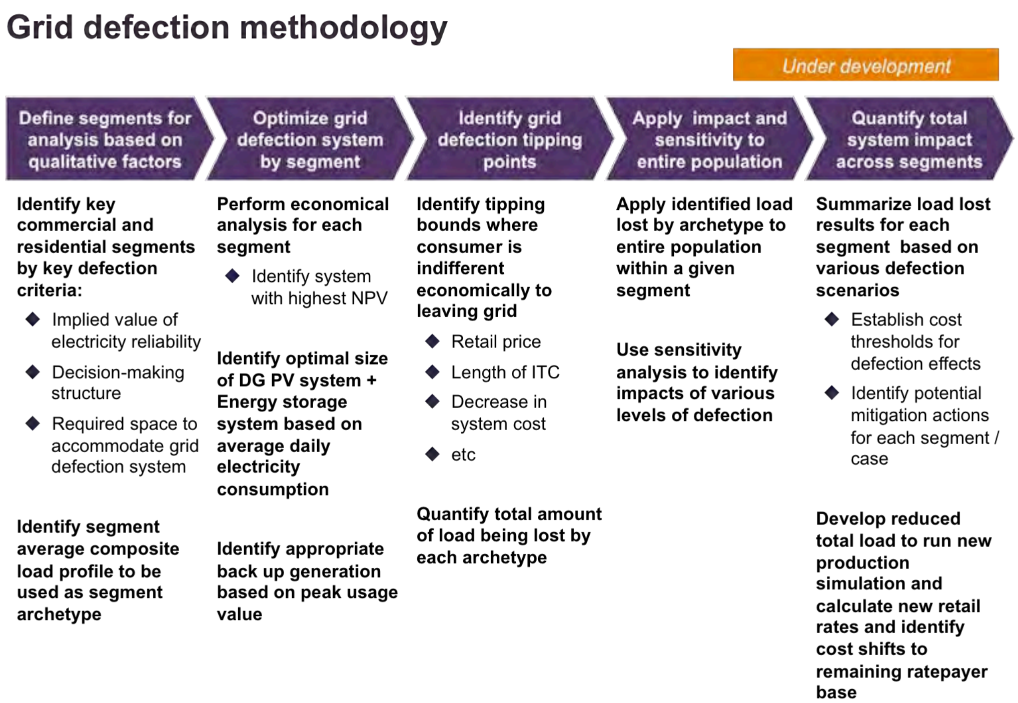

Figure C-27. Grid Defection Methodology (under development)

This methodology will allow the Hawaiian Electric Companies to explore and better understand the following areas related to grid defection:

- Potential tipping bounds of critical variables including: retail prices, technology costs and level of ITC to make grid defection an economically viable choice.
- Potential segments among ratepayer population that have highest likelihood of defection and impacts at different levels of defection.
- Impact of lost electrical load and corresponding shift of costs to the remaining ratepayer population.

This analysis will contribute to better understanding key risks around grid defection and will help inform potential mitigations to avoid adverse implications for all ratepayers.

POWERSIMM PLANNER MODELING TOOL

The electric supply system with increasing amounts of variable generation has broad needs for flexible generation to manage increased daily ramps, greater regulation requirements, substantial amounts of energy storage—all of which require closer analysis. Uncertainties also include the physical dynamics of weather driving renewable generation and load, uncertainty in adoption rate of DER, storage system capabilities and costs, and market prices of fuel and emissions.

Ascend Analytics' uses their PowerSimm software to simulate future conditions to capture system operations at a more granular level necessary to properly plan for a 100% renewable supply portfolio. Our software models at the minute level, and employs stochastic programming to select the most robust resource plan to meet future needs.

Ascend analyzed converting the current generation fleet to firing to LNG. Our analysis determines the optimal power supply resource mix. Our PowerSimm software:

- Determines optimal expansion plan with consideration of costs, system reliability and flexibility, resource adequacy, and uncertainty of fuel prices, carbon, and meteorology impacting renewable generation and load.
- Provides a robust evaluation of the economic merits of CCs, ICEs versus flexible storage for O‘ahu that captures the extrinsic value of each asset type to provide flexible energy and ancillary services.
- Determines the change in costs and risks in costs for meeting PSIP portfolio emission constraints without LNG.
- Develops optimal unit retirements with consideration of costs, resource adequacy, and system flexibility needs.
- Develops a detailed economic evaluation of energy storage system relative to alternative supply from either fossil fuel or biomass resources.
- Evaluates the cost effectiveness of energy storage for regulating reserve using sub-hourly modeling.
- Determines the relative value of customer demand response.
- Determines regulation and contingent reserve requirements for each island as a function of solar and wind.
- Determines the cost tradeoff between renewable curtailment and alternative actions of either cycling thermal generation or utilizing storage.

Ascend Analytics is the leading energy analytics software company that serves as the analytic infrastructure supporting portfolio management and planning decisions for Duke, TVA, AEP, AES, NRG, and a host of other utilities. Ascend has distinguished itself from the competition by providing analytic solutions that systematically capture and incorporate uncertainty into the decision making process. In addition, Ascend models physical system operations in greater details than other production cost modeling and planning software. In 2014, Ascend supported the nearly $1 billion acquisition of renewable hydro generation in Montana resource plan for NorthWestern Energy. The resource plan proceedings were conducted in the Montana Supreme Court Chambers with Ascend testifying and receiving the distinction of modeling "fully consistent with industry best practices" by the independent experts retained by the Commission to review Ascend's modeling.

PowerSimm Planner

Ascend Analytics completed analysis in 2015 that valued for Hawaiian Electric the conversion of its oil based generation fleet to LNG. Through this PowerSimm modeling analysis, Ascend proved the value of a structured framework that models uncertainty in key risk drivers including: weather, load, renewable generation, renewable penetration rates, and market fuel prices and carbon. Ascend plans to leverage these modeling capabilities of uncertainty combined with a more granular physical representation of Hawaiian Electric's power supply system at the minutely level. In addition, Ascend plans to expand upon the detailed modeling of minutely level system operations to determine the optimal power supply resource mix inclusive of uncertainty. The use of minutely dispatch operations also supports evaluation of system capabilities to meet dynamic ramps and maintain system frequency.

Ascend brings the unique capability to model system operations in greater physical detail over a broad spectrum of future operating conditions at a granular level of minutely dispatch. In addition, Ascend's capacity expansion logic integrates the more granular system modeling and uncertainty to pick the most robust supply plan to meet Hawaiian Electric's future needs over a broad spectrum of future simulated meteorologies and market prices.

Ascend has found that while deterministic runs with sensitivities provide insight into portfolio management decisions, the limited set of information of deterministic runs compared to probabilistically enveloping future states through Monte Carlo simulations can bias results. Furthermore, by simulating future conditions with "meaningful uncertainty" we can better articulate dimensions of risks for each of the future supply portfolios.

PowerSimm Planner's capacity expansion module determines optimal future supply portfolio(s) by selecting the best supply portfolio over all simulated future conditions. This is a substantial improvement over other solutions that are limited to picking the best portfolio over a single deterministic run (and often with only load duration curve granularity). By determining the best portfolio over all future states, PowerSimm provides a more robust future supply portfolio.

Description of PowerSimm Planner

PowerSimm Planner provides optimal resource planning analysis that combines detailed system operations, including minutely level dispatch modeling, with simulations of the principal risk factors determining physical and financial uncertainty. PowerSimm Planner directly incorporates risk into to the resource selection process by finding the optimal expansion plan over a broad set of future simulated conditions to jointly minimize costs and risks. The selected optimal resource expansion plan(s) provides distributions of costs where risk can be monetized as a direct cost; thus, enabling uncertainty to be valued in direct comparison of alternative expansion plans.

Underlying the risk based decision analysis framework of PowerSimm Planner are simulations of future conditions that rigorously realize the standard of "meaningful uncertainty". The realization of physical uncertainty begins with weather and then the resultant load and renewable generation levels. Financial uncertainty extends to commodity prices for fuel following market expectations of future prices uncertainty including episodic high and low price events. Carbon is also simulated based on ranges in forecast expectations of carbon prices.

System operations are measured down to minutely level generation and load with determination of ancillary service components of regulating reserves and contingent reserves as a function of renewable generation levels. The more granular dispatch conditions enable the physical system modeling to reflect actual system operations chronologically through time.

Recognizing the computational burden of the simulations, dispatch, and summary of results, Ascend utilizes a massively parallel distributed computing system: "The Ascend Cloud". This highly tuned bank of computers provides supports resource planning analysis without compromising the modeling. The model inputs and outputs can be readily accessed through the accessing the Ascend Cloud.

PowerSimm Resource Selection

PowerSimm Planner performs optimal capacity expansion planning to determine the least cost and least risk resource options to meet future load. The optimal expansion plan analysis determines the least cost resource mix to meet a target reserve margin to maintain system reliability. Because utility planning involves a trade-off between long-term capital investment decisions and variable operating costs, the optimal expansion plan seeks to minimize the net present value (NPV) of future variable and fixed costs. To account for capital investment decisions not fully amortized over the 20 year planning horizon, we utilize the levelized cost for future resource options.

The expansion planning problem can be more formally stated as:

Minimize: Portfolio Costs (PC) = PV (Net Power Cost) + PV (Fixed Cost)
Subject To: Resource Adequacy Requirements
RPS standards
Regulation and contingent reserve requirements
Thermal generation operating characteristics
Battery storage operating characteristics and life cycles

Where,
Costs = Net Power Costs (NPC) + Fixed Costs (FC)
Net Power Costs (NPC) = Fuel + Variable O&M+ Emissions
Fixed Costs = Fixed revenue requirement of portfolio in each year calculated from the financial model

The addition of new generation resources follows from both the requirement to ensure reliable generation supply and the economics of new generation.

It has been established that while using deterministic runs with sensitivities provides insight into portfolio management decisions, the limited set of information used in deterministic runs bias results. This bias is not observed in the broader realized through probabilistically enveloping future states through Monte Carlo simulations. Figure C-28 illustrates this effect by taking the expected value of Monte Carlo simulations shown in the solid black line that removes the bias of the orange line by depending on a limited set of future conditions. Furthermore, by simulating future conditions with “meaningful uncertainty” we can better articulate some dimensions of risks of each of the proposed portfolios.

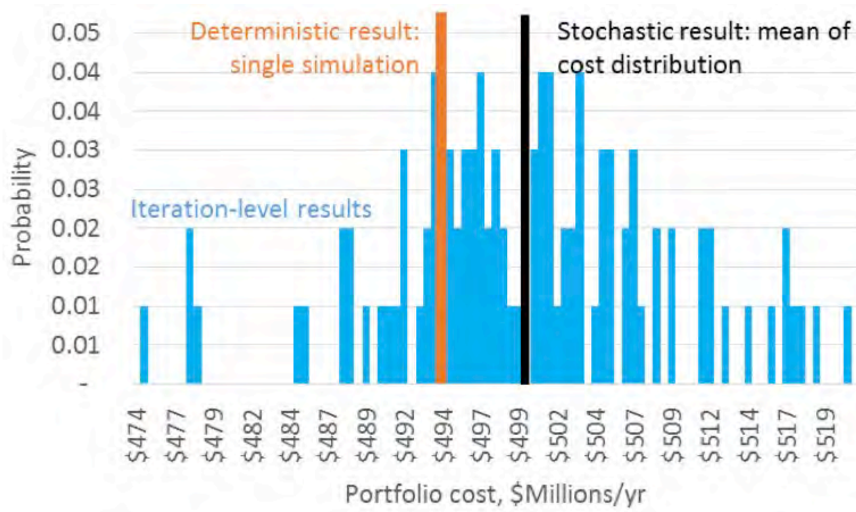

Figure C-28. Deterministic versus Stochastic Simulation Based Results

The use of Monte Carlo simulations can be combined the Resource Selection module of PowerSimm Planner to systematize the resource selection process. PowerSimm's Resource Selection module automates the resource selection process of determining the optimal future supply portfolios. The methodology of the Resource Selection module provides the best supply portfolio overall simulated future conditions. The ability to select the optimal portfolio over a broad spectrum of future conditions without loss of generation modeling details provides substantial advantages over picking the best portfolio from a single deterministic run. The optimization of future supply portfolio utilizes a stochastic dynamic program to minimize the net present value of costs over all simulations subject of a series of constraints most notably capacity. By determining the best portfolio overall future states, PowerSimm provides a more robust future supply portfolio.

For purposes of illustration, Ascend draws a sporting analogy for resource selection under uncertainty. Selection of an optimal resource portfolio over the first deterministic run is equivalent to finding the best swimmer (Michael Phelps) and the second run may be akin to the best cyclist (Chris Froom), and the third would be the best runner (Ryan Hall). In resource planning, we're not interested in the best athlete for any individual event, but the best athlete over all three events (Figure C-29). We want the best tri-athlete, the best resource portfolio over a broad set of future states. The portfolio may not be the best for any individual future run. However, the portfolio performs the best overall future states. Ascend utilizes stochastic dynamic programming for capacity expansion planning in a Monte Carlo simulation framework (Figure C-29).

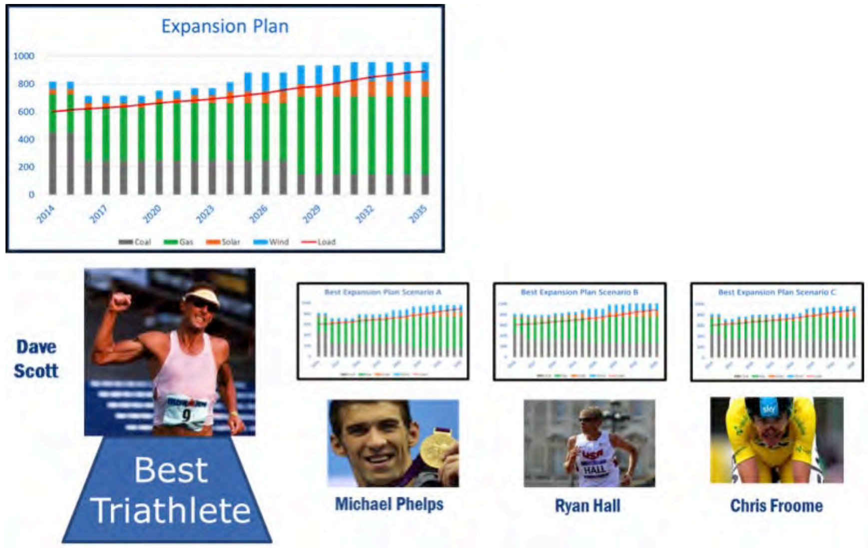

Figure C-29. Triathlete Analogy to Expansion Planning

By incorporating uncertainty into the expansion planning process, this analysis builds upon the concept of risk and simulations that produce "meaningful uncertainty" introduced in the 2013 Plan. The challenge of incorporating uncertainty into capacity expansion planning is further met by the need to address the value of resource flexibility. The modeling requirements to account for resource flexibility require utilizing hourly simulations and modeling asset start-up and shut down costs and times and generation ramp rates. More flexible resources can quickly and cost effectively cycle—a core asset attribute to support the addition of more renewable generation. The addition of uncertainty and detailed hourly generation characteristics distinguishes the rigor of capacity expansion planning used in this analysis. Table 1 summarizes the analytical differences between the PowerSimm model and traditional capacity expansion models.

Area of Model Comparison	PowerSimm Planner	Common CapEx Models	Comment
Physical generation asset operating characteristics (heat rate curves, ramp rates, min-up, min-down…)	√	X	Common CapEx models have no ability to capture asset operating characteristics other than plant capacity. Integrated models dispatch generation consistent with the full set of plant operating constraints. By overlooking the physical constraints of asset operations, Strategist introduces potential biases and inconsistencies with respect to selection of intermediate and peaking resources by not modeling asset flexibility.
Chronological relationship of load	√	X	Common CapEx model use load duration curves, which removes the hourly and daily pattern of load.
Chronological relationship to market prices	√	X	Common CapEx models use of price duration curves removes the hourly and daily pattern of market prices. Moreover, the structural relationship between system load and market prices are not maintained.
Imports/exports	√	√	Both models account for imports/exports but the inability of Common CapEx models to capture physical asset details introduces resource selection biases and inconsistencies. For example, a peaking unit may be designated as having the ability to provide exports when the start-up and shut-down costs or minimum run-times may make an off-system sale uneconomic.
Ancillary Services	√	X	Common CapEx models do not have the ability to model ancillary services.

Table C-73. Distinction of PowerSimm from Common Capacity Expansion Models

Simulation Framework

PowerSimm develops realistic simulations of future conditions to probabilistically envelope the expected value and range of potential future cases. The simulation of future conditions is initiated with prior-to-delivery simulations of forward/forecast prices shown in the lower left of Figure C-30. Upon evolution of the forward/forecast prices to the final evolved monthly price expiration. Weather simulations then drive renewable generation and load. Spot prices are then simulated as a function of load, renewable generation, and other potential variables of supply.

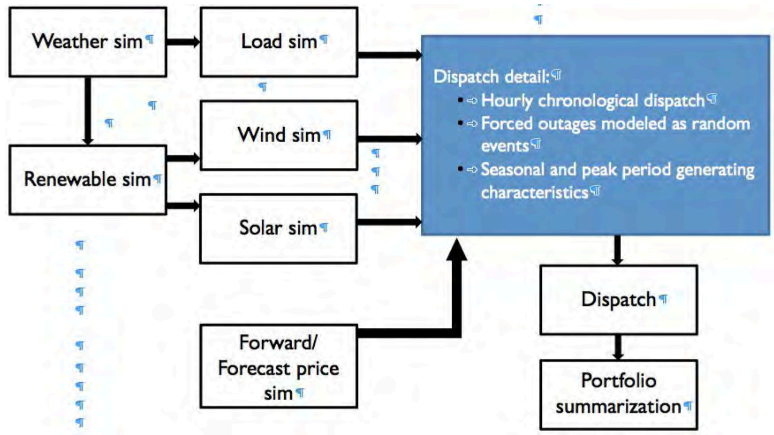

Figure C-30. PowerSimm Process Flow Diagram

The simulation framework of PowerSimm addresses uncertainty as viewed through today's market expectations (forward/forecast prices) and the future realized delivery conditions for load, spot prices, and generation. The framework to simulate physical and financial uncertainty follows the process flow of Figure C-30.

Simulation of Commodity Prices and Physical Components

Simulation of electric system and customer loads follows from a common analytical structure that seeks to preserve the fundamental relationship between demand and price. The simulation process is divided into two separate components: 1) prior to delivery and 2) during delivery. The prior-to-delivery simulation of forward/forecast prices evolves current expectations through time from the start date to the end of the simulation horizon. The simulations during delivery capture the relationship of physical system conditions (that is, weather, load, wind, solar, unit outages, and when applicable transmission). The inter-relationship between prior-to-delivery and during-delivery simulations is central to linking expectations to realized observations.

For forward/forecast prices representing prior-to-delivery simulations, monthly prices are evolved into the future from the current forward/forecast prices through expiration of each contract or forecast month. This process of evolving forward/forecast prices into the future draws on the observed behavior of forward contract variability and covariate relationships to create future monthly price projections. Within each prior-to-delivery simulation, observed commodity prices behavior, volatility, rate of reversion, and covariate relationships across commodities drive price movements to ultimately arrive at a final evolved price at delivery. The average of these final evolved prices across all simulations for each monthly price will equal the current forecast expectation of the price at delivery. Similarly, the average of the simulated electric spot prices for a given month will equal the current forecast price for that month. Seasonal hydro conditions are also correlated with the simulated forward/forecast prices.

The during-delivery simulation process begins with simulation of weather. PowerSimm simulates weather using a cascading Vector Auto-Regression (VAR) approach across multiple locations. This approach maintains both the temporal and spatial correlations of weather patterns for the region. Ascend applies a cascading VAR approach to maintain inter-month temperature correlations consistent with the historical data. For example, if a hot July day is likely to be followed by another hot July day, the cascading VAR method captures this effect. The application of weather simulations supports the analysis of uncertainty through hundreds of weather cases without the limitation of the pure historical record where extreme weather events beyond observed conditions may occur (but with a low probability). The second step of the process combines these weather simulations with other factors in the load simulation process.

Load and Price Simulation

PowerSimm uses the weather simulations as well as forecasted input load values, scaling and shaping the simulated load shapes to match forecasted monthly demand and peak demand values. The simulations of electric load use a state-space modeling framework to estimate seasonal patterns, daily and hourly time series patterns, and the impact of weather. The state-space framework of PowerSimm produces results that reflect the explained effects of weather and time-series patterns and the unexplained components of uncertainty.

The during-delivery simulation of prices addresses the more intuitive simulations of system conditions and spot prices. System conditions of unit outages, supply stack composition, system imports and exports, and transmission outages are separated independent of weather but can also serve as determinants to the spot price of electricity.

LONG-TERM CASE DEVELOPMENT AND RESOLVE

Achieving a 100% RPS in 2045 would require dramatic changes in how energy is generated and used. Traditional resource planning has focused on matching the peak load and reliability needs of the system with thermal generating resources to maintain the quality of service. Planning with increasing levels of energy from variable renewable resources shifts the planning paradigm away from maintaining sufficient peak capacity towards determining the quantity and type of measures needed to integrate those resources at least cost. This requires both new planning tools and a broad perspective on how energy is produced and consumed, with the potential addition of transportation as a substantial new end-use to the electric sector.

Given the multi-decade lifetime of infrastructure built today, the decisions made now and in the near future have a potentially significant impact on the ability to meet the 100% RPS target in 2045 as well as the ultimate total cost of achieving this goal. However, the long timeline also means significant uncertainty exists about future technology costs and capabilities, fuel prices, and other factors that may have a major impact on the cost of the transition. Hawaiian Electric and Hawaiʻi have no control over such factors; these are the future conditions that will *happen* to the islands. Understanding these factors and how they affect the cost effectiveness of investments made today is critical. Near-term decisions should be both consistent with the islands' long-term goals and robust against a range a future uncertainties. Another necessary step is therefore to identify the *controllable decision levers* available in formulating a *robust*, *least regrets* plan to best handle what happens in the future.

The differentiation between planning elements that *happen* to the islands versus those that are *decision levers* is dependent on many complex and interacting factors. Global market prices for fuels and technologies, as well as technological innovation, for example, fall into the first category; others such as battery procurement can be directly decided by Hawaiian Electric; but what about customer behavior, renewable resource portfolio diversity, or transportation infrastructure? These typically fall outside of the traditional Hawaiian Electric planning cases, but can be influenced by tariff design and policy development at the state level. Identifying these factors early in the planning process, engaging stakeholders in a discourse around the policy issues, and arriving at a consensus about the policy directives is critical to create long-term policy certainty and thus enable effective planning.

To address these key questions, Hawaiian Electric has contracted with the consulting firm, Energy and Environmental Economics Inc. (E3). They have multiple contracts with the California State Agencies to support their long term planning efforts to meet both

RPS and GHG reduction targets and were responsible for developing the four US Deep Decarbonization cases used in the COP 21 process to help reach climate agreements in Paris in December of 2015. E3 also has a long history working with both the Commission and Hawaiian Electric on energy issues in Hawai‘i.

In this analysis E3 will first investigate what the least cost planning decisions for Hawaiian Electric should be given current policy and economic trends on the islands to create a Business as Usual (BAU) case. E3 will then develop cases that satisfy potential policy directives to adapt to higher renewables. The cases will include cases that account for the value of creating a portfolio with more diversity, more control of variable renewable resources, the evolution of the transportation sector to electric vehicles or vehicles powered by hydrogen or synthetic natural gas, and flexible loads capable of responding to supply side needs. E3 will compare the costs of each of these cases and the decisions that need to be made to achieve them, forming the basis for discussion in a state policy decision process.

Case Development

Based on E3’s prior work for Hawaiian Electric exploring the operational impacts and integration requirements of higher renewable penetration levels on the islands, E3 will also identify and include in their analysis several current trends with significant implications for Hawaiian Electric’s planning processes. These trends include:

Low renewable portfolio diversity: high levels of customer adoption of rooftop solar PV

Non-dispatchable renewable supply: limited utility control (via curtailment) over renewable generation

Load inflexibility: limited ability of loads to respond to supply conditions

In Figure C-31, an illustrative example of how these trends might manifest themselves in a 100% renewable case is shown.

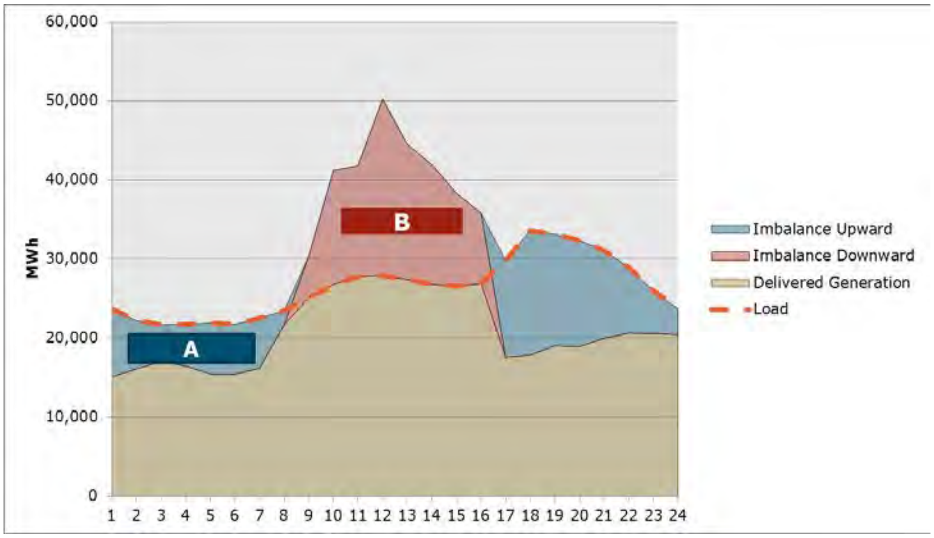

Figure C-31. Example Dispatch at 100% Renewables

In this case, the renewable portfolio consists of largely solar energy, so energy production is concentrated during the daylight hours. The load is assumed to be inflexible. The combination of these factors results in oversupply in the middle of the day (imbalance downward, B) and undersupply at night (imbalance upward, A). If the renewable generation were not curtailable, the consequence of the daytime oversupply would be an overgeneration reliability event. The nighttime undersupply results in a traditional loss-of-load reliability event. Building storage to meet such imbalances is the approach that is often considered, but such storage requires substantial capital investment and is potentially unsuited to imbalances that may persist over a number of days, or even weeks or months. Renewable portfolio diversity to reduce the oversupply levels or the deployment of load controllability equipment may be more cost-effective integration alternatives. Incorporating the available alternatives into a single modeling framework is necessary to identify trade-offs and synergies among them, and optimally combine them.

E3 will investigate a series of cases exploring potential futures in Hawai‘i to determine the planning solutions needed in each one. These cases will be defined by the factors on the system described by the categories in Figure C-32. Within each of these categories, E3 will investigate two or more different potential futures. Each case will be defined by a set of assumptions describing customer behavior, renewable diversity, and transportation infrastructure, reflecting the decisions Hawaiian Electric may have limited control over but may be impacted by state level policy developments.

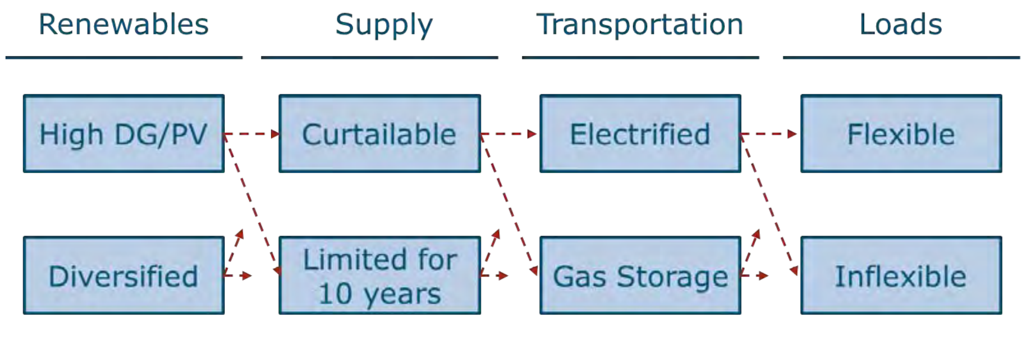

Figure C-32. Case Drivers of Potential Hawaiian Electric Futures

More specifically, they will explore the impact of the following policy decision points for Hawai‘i that are dependent on price and political drivers:

High consumer PV adoption versus diverse resource portfolio: E3 will analyze the differences among integration solution needs when consumer adoption of rooftop PV is allowed to grow to high levels compared to a more diverse portfolio of resources is deployed.

Curtailment of supply: E3 will explore the impact on resource plans of whether Hawaiian Electric has full control over curtailing new generation resources, compared to a case where contracts and/or technological constraints limit the curtailment capability for some time.

Low-carbon economy transition: in order to decarbonize the entire economy of Hawai‘i, either fossil-fueled services, such as transportation, will need to be electrified and served by clean electric generation, or a transition will be made to using gas, such as hydrogen or synthetic methane, as an energy carrier. E3 proposes to consider both load electrification and gas (hydrogen or synthetic natural gas) transition cases. Under the gas transition case, gas will be produced on the island and function as a controllable load with a daily consumption requirement. Conversely, in the base electrification case, E3 will use electric loads including EVs to balance renewable generation. Previous work has shown that electrification does not provide the same flexibility as the gas generation path but could ultimately be a less expensive decarbonization pathway for Hawai‘i.

Load participation: increasing levels of efficiency and substantial growth in flexible loads are a cornerstone of most long-term high RPS cases E3 has studied so far. The levels of flexible loads are partially dependent on tariff design, market development, technological capabilities and pricing for distributed generation technologies. The cases will explore the amounts and types of flexible loads needed to substantially mitigate integration challenges.

The simple matrix (shown in Figure C-32) leads to 8 Cases (4x2) that E3 will describe, provide input data for and model. The matrix is not meant to be an exhaustive list of all key drivers or decarbonization pathways, but is an attempt to develop a workable number of cases suitable for exploratory initial analysis and stakeholder discussion. The number of Cases can be expanded to include other critical elements or additional sensitivities based on initial results as well as feedback from either the Commission or key stakeholders. For each case, E3 will also explore sensitivities to the uncertainty around market fuel and technology pricing.

Modeling Approach

Developing Case Data

Variable renewable energy poses challenges to traditional electricity sector planning and procurement as well as day-to-day reliable operations of the grid. Analyses of these challenges generally focus on near-term issues related to supply-side flexibility. These challenges can often be solved within traditional paradigms of supply-side dispatch. However, such a focus may ignore the broader context and longer-term challenges and opportunities presented by transitioning away from imported energy, not just of the electric sector, but for the energy system more broadly. For instance, a large transformation in transportation away from internal combustion engines will have major implications for the electricity sector that need to be factored into long-term energy planning. E3 will draw on its work in developing deep decarbonization pathways (DDPs) for both California[24] and the United States[25] to develop multiple pathways and a strategic vision for transforming Hawai‘i's energy future. Combinations of the case drivers shown in Figure C-32 will form each of the cases investigated. Case development will consist of the following three tasks.

Task 1. Demand Case Development. As the first step in developing the vision for the electric sector under a 100% renewable penetration, E3 will focus on the potential for other energy system choices to impact the electricity sector. This will focus on new electric loads from:

- Direct transportation electrification (that is, electric vehicles)
- Building electrification
- Electric fuel production: Hydrogen electrolysis and Power-to-gas synthetic natural gas

These new loads affect the load shapes of the electric sector, the overall demand for electricity, and the potential supply portfolios that can meet their demand. This is a very

[24] https://ethree.com/public_projects/energy_principals_study.php.

[25] http://unsdsn.org/wp-content/uploads/2014/09/US_DDPP_Report_Final.pdf.

important context for the electricity sector not just for the challenges that these new loads pose, but for the opportunities they present. This will be a first-cut, case analysis to assess the scale of these potential impacts. E3 will develop Energy Transformation Case demand forecasts based on previous work developing DDPs for California and the U.S. These will focus on key choices in the transportation sector and buildings:

- Light duty vehicles
- Heavy-duty vehicles
- Buses
- Thermal end-uses (water and space heating)

E3 will utilize all available data for Hawaiʻi in order to develop a realistic assessment of future electricity demand from activities in these sectors.

Task 2. Renewable Portfolio Development. In this task, E3 will develop prospective renewable portfolios for supplying levels of overall electricity demand developed in Task 1. The first portfolio will be composed of reference renewable supply assumptions, with high levels of DGPV. Additional portfolios will be based on existing renewable energy potential data and reflect policy direction to procure the best prospective portfolios to minimize supply and demand imbalances (that is, 100% solar would exacerbate supply and demand imbalances) versus cost and development potential constraints. The level of resource curtailability will also be factored into the portfolios to reflect potential transition times to Hawaiian Electric's full control of the renewable fleet including DG-PV systems.

Task 3. Load Development. E3 will first assess the flexibility from the new loads detailed in Task 1. Many of these loads come associated with storage, which allows them to mitigate their demands on the electricity sector. For example, a car battery connected to the grid offers the ability to delay or advance its charging needs based on its inherent chemical storage capacity. End-uses in buildings offer thermal storage to perform activities like pre-cooling and pre-heating to manage loads with regards to supply conditions. Electric fuel production may be the most flexible of all, taking advantage of existing gas infrastructure or hydrogen storage to flexibly operate plants during periods of over generation.

E3 will also examine permanent load shaping. Here, targeted energy efficiency can reduce loads during times of the day where consistent supply deficits occur. For example, aggressive lighting efficiency can reduce nighttime load in a high-solar case, increasing the coincidence of demand and supply. Permanent load shifting could provide pre-cooling opportunities at mid-day to reduce nighttime cooling loads.

Developing optimal resource portfolios for each case

For each case – and selected fuel price and capital cost sensitivities – E3 will develop optimal resource portfolios for meeting the RPS targets using the E3 optimal investment model RESOLVE. RESOLVE is an optimization tool that selects a least cost portfolio of renewable resources and integration solutions over a chosen time horizon. It was built by Energy and Environmental Economics Inc. (E3) for the California State Agencies to study cost-effective integration solutions including demand response and a range of storage technologies, and to determine the value of regional integration in mitigating renewable integration costs. RESOLVE is described in more detail in the appendix.

Price sensitivities will be developed under each of the cases to include plausible future market price trajectories for both fuel and capital investments.

A number of factors will influence the cost effectiveness of a conversion of oil fueled generation to LNG including capital expenditures necessary for the conversion, oil and LNG price trends and spreads, and quantity of energy generated by the converted plants. The payback of thermal capital investments is also dependent on the expected energy demand, which is influenced by renewable energy production and energy use patterns.

The optimal resource mix will depend in part on the price trajectory of energy storage technologies. E3 does not have confidence that an accurate prediction of energy storage technology price can be made out to 2045. Therefore E3 will consider several price trajectories to evaluate the expected price impact on the resource mix.

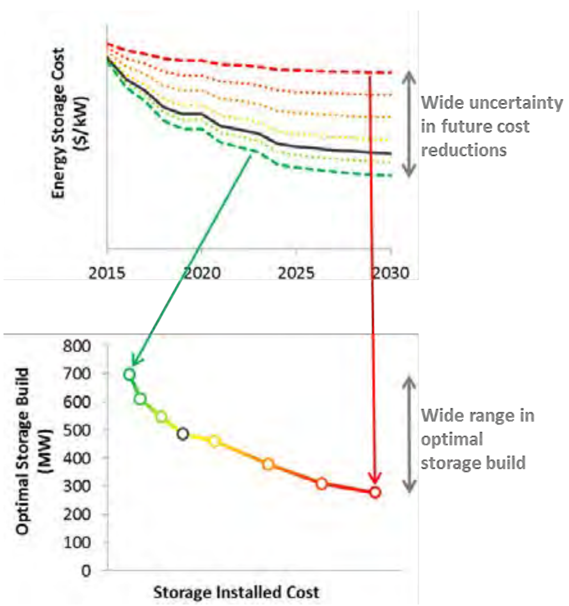

Figure C-33. Conceptual Effect of Storage Price Sensitivity

Beyond energy storage, a broad suite of integration solutions may be employed to meet the RPS targets (Table C-74) and will be explored. The applicability of many of these strategies relies on decisions made outside the electricity sector itself (ex. EV penetration determines the availability of EV load to manage imbalances).

Resource	Balancing Direction	Balancing Timeframe	Resource Potential
Flexible building thermal loads	Both	Seconds to Hours	Depends on electrified thermal end-uses, controllable equipment, and customer participation
EV Charging Management	Both	Seconds to Hours	Depends on available public and private infrastructure as well as overall electric vehicle penetration
Hydrogen Electrolysis	Both	Seconds to Weeks	Depends on demand for hydrogen in other sectors (primarily transportation)
Power-to-Gas Synthetic Natural Gas	Both	Seconds to Months	Depends on demand for gas as well as available gas storage facilities
Targeted Energy Efficiency	Upward	Hours	Depends on end-use electricity demands
Permanent Load Shaping	Both	Hours	Depends on building loads and customer incentives
Battery Storage	Both	Seconds to Days	Effective balancing but at high capital cost and efficiency penalty
Pumped Hydro	Both	Seconds to Months	Depends on site availability
Flexible Renewable Generation	Upward	Minutes to Days	Depends on available renewable fuels (geothermal)
Flexible Thermal Generation	Both	Seconds to Hours	Depends on price of available fossil fuels
Curtailment	Downward	—	Depends on controllability of renewable resources
Island Transmission Interconnection	Both	Seconds to Hours	Balancing benefits depend on the complementarity of load and renewables being connected

Table C-74. System Balancing Options

How these balancing solutions may be deployed in the context of a low-carbon electricity grid is shown in an example from the U.S. DDPP analysis (Figure C-34). This chart shows the Western Interconnection in a high renewables case during a week in March. In this case, high penetrations of renewable generation necessitate the dispatch of flexible fuel production, battery storage, flexible building loads, and EV charging in order to effectively manage periods of over and under-supply. Those loads are available for dispatch because of the electrification of transportation under this case. As control over energy supply is reduced, participation from other resources like loads will be a critical element for maintaining a low-cost, reliable electricity grid.

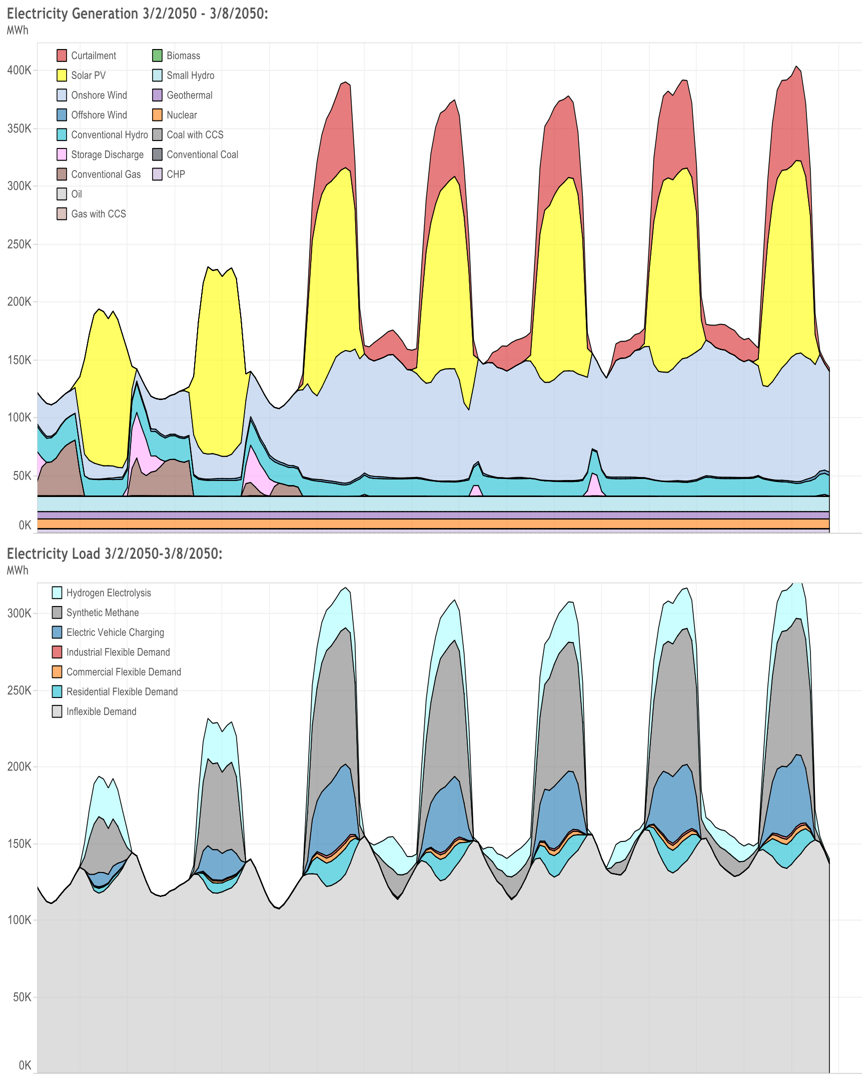

Figure C-34. Dispatch at 100% Renewables: Supply (top) and Demand (bottom)

Economic Selection of Optimal Renewable Integration Solutions using RESOLVE

Planning the development of a 100% RPS compliant electric energy system presents a number of challenges. The plan must choose a portfolio of varied resources that work in concert to reliably meet consumer electricity demand while accommodating the variability of renewable energy resources. Every hour of the planning horizon, the system must satisfy several operational constraints including reliability needs, for example generator minimum generating levels, ramping constraints, contractual obligations, and reserve requirements. The following figure shows a hypothetical day when generating resources must operate to meet the following constraints:

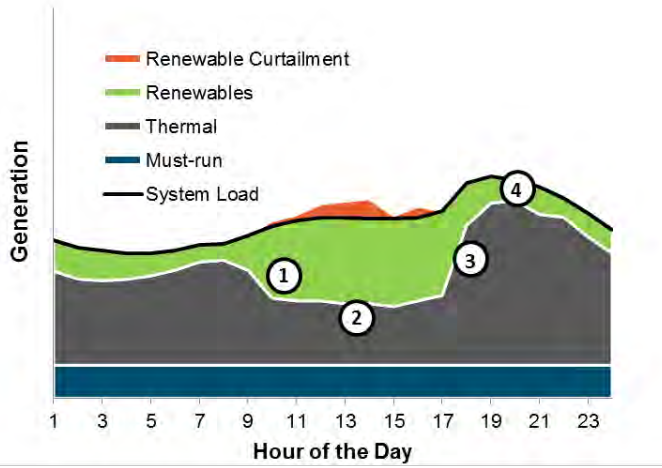

Figure C-35. Renewable Integration Challenges

1. **Downward ramping capability.** Ramp capability must be available to meet morning ramps as solar production increases and the net load drops.
2. **Minimum generation.** Resources must be capable of lowering their output sufficiently, either by turning off generation, or ramping down output, such that low midday net loads are balanced while reliability requirements are still met.
3. **Upward ramping capability.** Ramp capability must be available to meet capacity needs as solar production falls in the evening.
4. **Peaking capability.** Peak loads must be met, often after solar generation has dropped off.

There are many different combinations of resources that can be included in the resource portfolio to meet reliability needs, so determining the least cost portfolio must be done through an optimization framework. Figure C-36 shows the resource mix under three hypothetical renewable integration strategies.

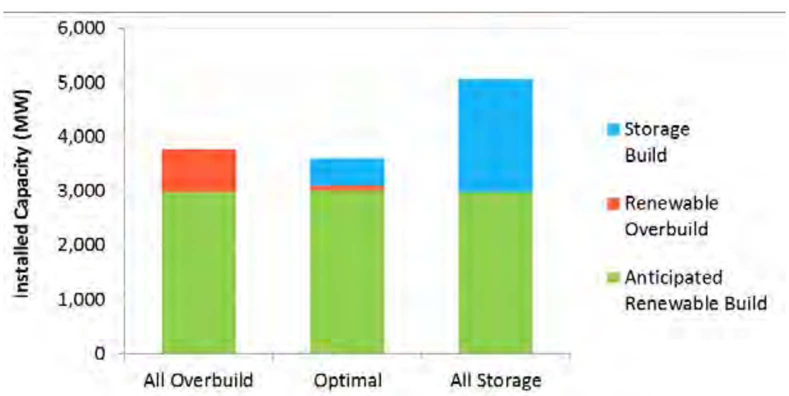

Figure C-36. Hypothetical Renewable Integration Strategies

The lowest cost portfolio of renewables and integration solutions at any point in time will be a mix of resources that minimizes both operating costs and capacity expenditures over the planning horizon. The value of each integration solution will change over time depending on the evolving needs of the system. Those selected in an optimal resource portfolio will offer the greatest net value over their lifetime in combination with the other resources selected. Some technologies may be stepping stones to longer term portfolios. In addition, a robust analysis will incorporate the costs of the enabling technologies on the grid (for example, interconnection, control systems). Figure C-37 depicts an optimal tradeoff between renewable overbuilding and other integration solutions. The optimal point for each resource will be where the benefit of the marginal unit of any resource to the system is equal to its marginal cost. In reality, each type of resource adds a dimension to the optimization and each combination of resources will have complex operational interactions. Finding the least cost solution requires a sophisticated optimization model that treats operational and investment costs while satisfying operational and reliability constraints.

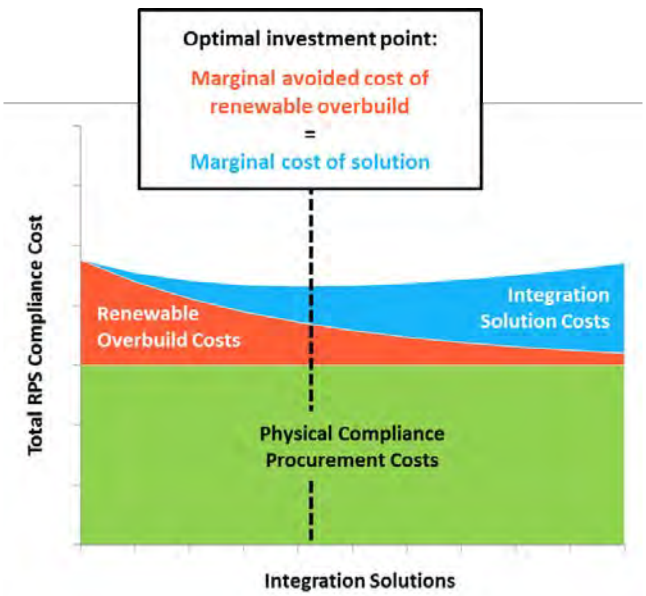

Figure C-37. Tradeoff Curve Between Integration Strategies

The optimal resource mix will depend on a number of assumptions about the future state of the world at large. An optimal resource plan should be robust to uncertain future trajectories of fuel prices, technology costs, and consumer adoption of DER.

For each case investigated in the analysis, E3 will use its RESOLVE optimal capacity investment model to optimize resource portfolios over a planning horizon out to 2045. RESOLVE builds on the REFLEX advanced production simulation model to optimize investment decisions subject to detailed hourly operational constraints including reserve requirements, ramping limitations, and unit-commitment constraints. Using their demonstrated methodology, Ascend Analytics will determine the electric power system's operating and contingency reserve requirements on an annual basis. These reserve requirements will be input data for RESOLVE. RESOLVE will then determine an optimal resource plan that adjusts the portfolio of resources on an annual basis. RESOLVE will select the optimal portfolio of resources to be installed in each year, choosing from generation retrofits, battery energy storage, demand management, thermal generation, and renewable generation. The solution found by RESOLVE will co-optimize investment and operational costs.

E3 will develop long-term strategic options for the electric sector under high penetrations of renewable energy. In looking out over the full planning horizon and considering the uncertainties involved, E3 will identify near term *least regrets* planning decisions.

PLEXOS® FOR POWER SYSTEMS

PLEXOS provides a platform for economic analyses of energy systems that co-optimizes the contributions from energy, ancillary services, fuels, emissions, water resources, and transmission systems from sub-hourly chronological scheduling to analyses of long-term planning. The model datasets for the islands are developed from reference case assumptions provided by Hawaiian Electric. PLEXOS provides detailed modeling of the generation resources, including thermal, wind, solar PV, battery storage, demand response, distributed energy resources, hydroelectric resources, and pumped-storage hydro in these data sets. Energy Exemplar provides output from the island data sets for benchmarking with existing models used by Hawaiian Electric.

Energy Exemplar contributes data in capacity expansion plans for all five islands combined with economic analyses of those expansion plans. The expansion plans are produced under several cases. Energy Exemplar will continue this modeling to contribute data for the Updated PSIPs.

The Energy Exemplar project team are highly trained and experienced in implementing PLEXOS models and the economic analysis of power systems. The PLEXOS modeling approach implements its models as physical systems with economic and financial impacts. The model uses engineering inputs for generation resources, resulting in operational and financial outputs that depend on forecasts of market conditions (such as fuel prices and contract positions for the scarce resources that power the various assets). PLEXOS is reliable simulation software using state-of-the-art mathematical optimization combined with the latest data handling. Combined with visualization and distributed computing methods, the model provides a high-performance, robust simulation system for electric power that is leading edge, open, and transparent. PLEXOS meets the demands of energy market participants, system planners, investors, regulators, consultants, and analysts with a comprehensive range of features seamlessly integrating electric, water, gas, and heat production, transportation and demand over simulated timeframes from minutes to decades. PLEXOS is the fastest, most sophisticated, most cost-effective software available for performing the analyses required to develop Hawaiian Electric's PSIPs.

PLEXOS is reliable simulation software that uses state-of-the-art mathematical optimization, combined with the latest data handling, visualization, and distributed computing methods, to provide a high-performance, robust simulation system for electric power, water and gas. Its processing is open and transparent. PLEXOS meets the demands of energy market participants, system planners, investors, regulators, consultants, and analysts with a comprehensive range of features. The model seamlessly integrates electric, water, gas, and heat production; transportation; and demand over simulated timeframes from minutes to decades—all delivered through a common simulation engine with easy-to-use interface and integrated data platform. PLEXOS is the fastest and most sophisticated software available today for the task at hand, and also the most cost-effective.

Energy Exemplar developed PLEXOS datasets to model generation resources for O'ahu, Maui, Hawai'i island, Lana'i, and Moloka'i. Each island model implements two modeling approaches:

- Unit commitment and economic dispatch to evaluate the economics of the generation system (including energy and ancillary services).
- Capacity expansion modeling for portfolio optimization and RPS modeling.

The analysis includes evaluating DR programs, existing economic fleet retirement, expansion to satisfy RPS targets (including renewable and traditional resources), expansion, and economic modeling of battery storage devices. This tool also develops sub-hourly models to capture the benefits conveyed by flexible resources, especially in a resource mix that includes high variable renewable penetration.

FINANCIAL FORECAST AND RATE IMPACT MODEL

PA Consulting Energy and Utilities team developed the Financial Forecast and Rate Impact Model specifically for modeling the impacts of key metrics (such as revenue requirements, rates, and average customer bills) for the Updated PSIPs. The model's design reflects important and unique characteristics of the Companies' business: timing and frequency of rate cases, revenue adjustment mechanisms (RAM), maintenance of the target capital structure, and customer usage and bill composition. We initially developed this financial model for the filed PSIPs. Since then, we have refined and updated the model to reflect the most current conditions, including recent regulatory changes to the RAM.

The model comprises a comprehensive and interconnected set of detailed modules, each representing a key aspect of the company's financial framework. These modules calculate average customer bills, income statements, cash flow statement, and balance sheets. Additional modules, in turn, calculate detailed schedules of annual capital expenditures, and annual debt and equity issuances.

The model's foundation uses the PSIP case variables to build a range of company financial data, including:

- Annual reports (income statements, cash flow statements, and balance sheets)
- Schedules of existing debt
- Operation and maintenance (O&M) expenses not covered by the PSIPs
- Annual capital expenditures not directly covered by the PSIP cases (transmission, distribution, and other general expenditures)
- Rate structures
- Projections of customer count and average usage
- Sales forecasts
- Most recent net plant values for all generation units

The Financial Forecast & Rate Impact Model requires two key inputs for each PSIP case—production costs (such as fuel prices, power purchase agreements (PPAs), variable and fixed O&M expenses) and incremental capital expenditures. From this input, the model automatically updates all modules to reflect the resultant financial impact on each PSIP case. These financial impacts—pass-through of fuel and PPA costs, application of the appropriate RAM and surcharges for the capital expenditures, updated rate case calculations, and revised debt and equity issuances—lead to updated revenue requirements, rates, and average bill values.

PA Consulting Group's Energy and Utilities team is uniquely qualified to create and implement this financial model. We have extensive experience in utility accounting, complex financial modeling, and support of rate cases and other regulatory filings.

Several Modules Comprise the Modeling Tool

PA Consulting Group's Energy and Utilities team updated and refined this model that was specifically created to perform financial analysis for the Companies' PSIPs.

The Financial Forecast and Rate Impact Model is comprised of several modules (Figure C-38). The model also includes a discussion that contains the inputs feeding into the calculation modules, and a dashboard that captures all the major outputs from the various modules.

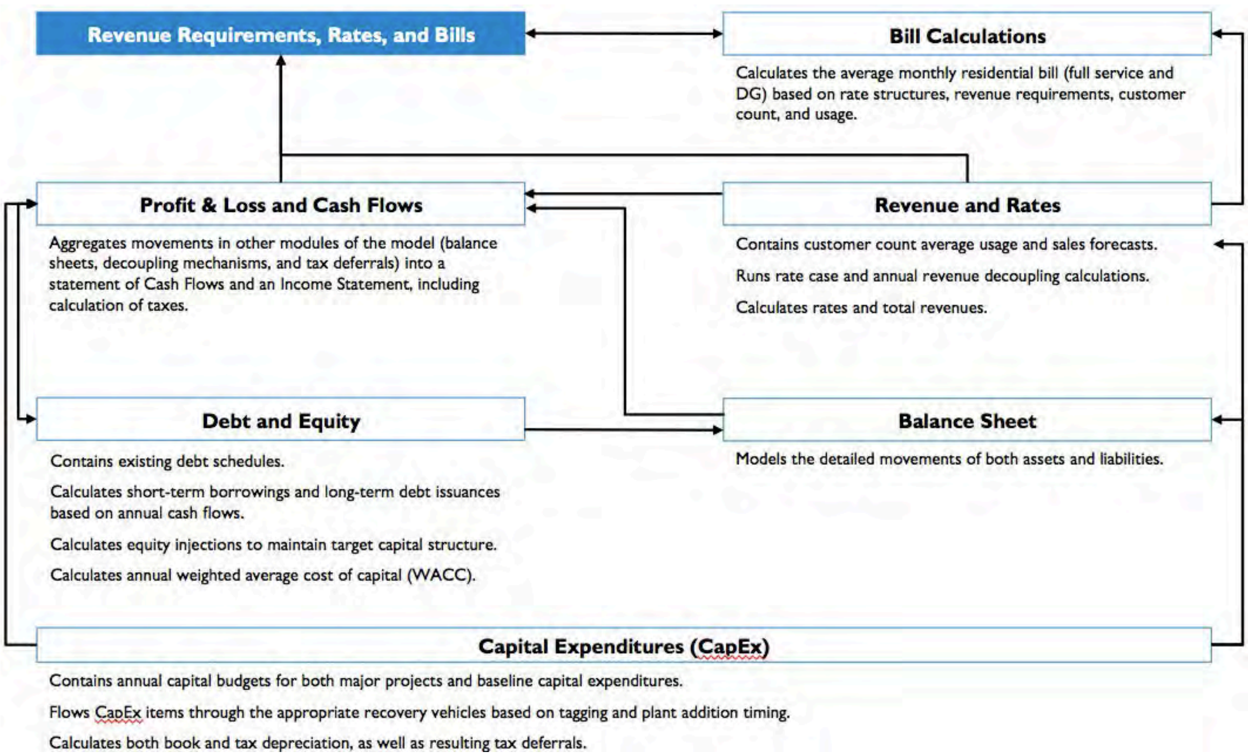

Figure C-38. High-Level Module Structure of the Financial Forecast and Rate Impact Model

Bill Calculations

This module calculates the average monthly bill for full service and DG residential customers. It:

- Calculates average bills under both current rate structures and proposed DG 2.0 framework, with fixed rates calculated for both cases.
- Bases the bill calculations on forecasts of annual number of DG customers and usage, production, and export for an average DG customer.

Profit & Loss and Cash Flow

This module primarily aggregates movements from other modules of the model (for example, balance sheet, decoupling mechanisms, and tax deferrals) into a statement of Cash Flows and an Income Statement.

For the statement of Cash Flows:

- Produces detailed schedules of operating, investment, and financing cash flows.
- For operating cash flow, key inputs from other modules include depreciation, change in tax deferrals, change in regulatory assets, and change in accounts receivable and accounts payable.
- Investment cash flow is driven by capital expenditures, which are calculated and picked up from the CapEx module.
- Financing cash flow is driven by the base dividend payments calculated from Net Income in the Income Statement, combined with the debt and equity issuances, and additional dividend payments calculated in the Debt and Equity module.

For the Income Statement:

- Key movements picked up from other modules include Total Revenues, Revenue Balancing Adjustment (RBA), depreciation, and interest expenses.
- Fuel, PPA, and variable and fixed production O&M costs come directly from the PSIP production simulation input, while the remaining O&M items are escalated annually by inflation, adjusted for any specific project-related savings or cost increases.
- Income and revenue taxes are calculated directly, with tax deferrals added from the CapEx module.

Revenue and Rates

This module contains various calculations that add up to a total annual revenue requirement:

- Periodic rate case calculations, with both a calculation of allowed return in order to adjust rates, and a calculation of net allowed revenue for RBA adjustments.
- Detailed RAM and RBA calculations, which reflect the most recent adjustments to the RAM.
- Mark-up of fuel and PPA costs by the revenue tax adjustment factor, to allow pass-through in rates.
- Calculation of total effective rates, by summarizing and adding up the different rate components contributed by RAM, RBA, other surcharges, rate case adjustments, and fuel and PPA pass-through.

- Calculation of total annual revenues, by multiplying the total effective rate with the total forecasted sales provided by (and used in) the PSIP production simulation.

Debt and Equity

This module calculates short-term borrowing, long-term debt issuance, equity injections, and additional dividend payouts:

- Based on an objective to maintain a minimum ending cash balance, short-term borrowing, and long-term debt are used to cover any shortfalls from the net cash flow before financing. Short-term borrowing is exhausted first, with any remaining shortfall covered by long-term debt.
- Upon issuance of debt, equity injections are calculated (if necessary) to maintain the target capital structure.
- Interest expense on new debt is calculated, with short-term borrowings carrying full interest expense in the year of issuance, and long-term debt carrying half a year's interest expenses in the year of issuance, and a full year of interest expense starting in the year following issuance.
- In years with equity over the target ratio, the model calculates additional dividend payments to achieve target capital structure.
- The weighted average cost of capital by year is calculated based on currently-authorized equity returns and forecasted debt rates using the target capital structure.

Balance Sheet

The module presents detailed annual assets movements, including:

- Utility Plant in Service, Accumulated Depreciation, and Construction Work in Progress, driven by annual changes of these items in the CapEx module.
- Annual change in Customer Accounts Receivables are based on annual relative change in Total Revenues.

Also presents detailed annual liabilities movements, including:

- Common Stock and debt balances are driven by calculations in the Debt and Equity module
- Any increase in Retained Earnings is net of any additional dividends paid out as part of the optimization of the capital structure.
- Accounts Payable adjusted annually based on average relative annual change in capital expenditures, fuel, and PPA costs.

For both assets and liabilities, all items that are not explicitly driven by calculations in other parts of the model are kept constant.

Capital Expenditures (CapEx)

This module contains detailed annual capital budgets, and calculations of surcharges, securitization (if applicable), and depreciation (book and tax). The module:

- Details capital expenditures and plant additions by year for baseline and major projects (RAM definition).
- Summarizes plant additions by asset category for depreciation purposes and allows for the inclusion and exclusion of specific projects depending on the cases modeled.
- Summarizes plant additions by surcharge category (Preapproved Baseline, Major Project, or REIP) for decoupling calculations in the Revenue and Rates module.
- Calculates average baseline capital investments for use in the RAM adjustment.
- Calculates accumulated depreciation and depreciation expense by asset (production plant) and by asset category (transmission, distribution, and general).
- Calculates tax depreciation and subsequent deferred tax impact on book and tax depreciation differences.
- Calculates the annual securitization payments associated with the retirement and removal of individual generating units (if applicable).

D. Planning Assumptions Discussion

For the 2016 updated PSIP analyses, we have reevaluated virtually every assumption used as input for our analyses. These assumptions include, but are not limited to:

- Existing generating units
- Replacement utility-scale generation options
- Utility energy storage resource options
- Fuel price forecasts
- Demand and energy sales forecasts
- Distributed energy resource potential
- Demand response potential
- System operating criteria
- System reliability criteria

While we have used these assumptions in our analysis to date, they are still preliminary. Based on further analysis, however, some of these assumptions could change while others might be added. Our Updated PSIPs will present the definitive list.

PLANNED CHANGES TO OUR GENERATING RESOURCES

Existing Generating Units

Waiau 3 and Waiau 4

Our analysis assumes that Waiau 3 and Waiau 4 will be deactivated at the end of 2017, however these generating units may need to remain in service until the end of 2020 to address potential capacity shortfalls.

The 2014 PSIPs targeted these units for deactivation at the end of this year, 2016. However, our 2015 Adequacy of Supply (AOS) reported a reserve capacity shortfall of 50 MW, beginning in 2017 if these units were deactivated as previously planned. This is based on a Loss of Load Probability (LOLP) guideline of 1 day in 4.5 years. The AOS report stated that reserve capacity shortfalls could be mitigated by "by deferring future deactivation of units, increasing Demand Response Programs, reactivating units that are currently deactivated, or acquiring additional firm capacity through a competitive bidding process".

Our 2016 AOS report assumed the deactivation of Waiau 3 and Waiau 4 at the end of 2017 to avoid a capacity shortfall in 2017, however shortfalls are still projected for 2018 and 2019, even if the Schofield Generating Station is in service in 2018. Delaying the deactivation of Waiau 3 and Waiau 4 beyond 2017 virtually eliminated reserve capacity shortfalls. A small reserve capacity shortfall is still anticipated in 2018.

We will continue to monitor factors that determine the best timing for deactivating Waiau 3 and Waiau 4. These factors include system demand, net of customer-sited distributed generation and demand response, availability of new generating capacity (from AES and Schofield Generation Station), and the unavailability of capacity because of scheduled or unscheduled maintenance.

Honolulu 8 and Honolulu 9

The PSIP analysis assumes that Honolulu 8 and Honolulu 9 remain deactivated

Our 2016 AOS report assumed Honolulu 8 and Honolulu 9 remained deactivated until 2020 and beyond. We would not need to reactivate these units if the deactivation of Waiau 3 and Waiau 4 were deferred until the end of 2020, and the Schofield Generating Station came online in 2018

Higher than forecasted peak demand might cause reserve capacity shortfalls.[26] We would reactivating Honolulu 8 and Honolulu 9 would need to be considered if significant reserve capacity shortfalls are projected, but only after implementing other mitigating measures (such as running new DR programs, acquiring additional firm capacity, deferring unit deactivations, and refining generating unit planned outage schedules). Reactivating Honolulu 8 and Honolulu 9 would take about three months.

Maui Electric

Our analysis assumes that all units on Moloka'i, and Lana'i are active and operating. On Maui, Kahului 1 and 2 are currently deactivated. However, these units are counted towards firm capacity because they can be, and are, reactivated when needed to maintain system reliability.

Maui Island has two generating stations and one distributed generation site. Our Kahului Power Plant has four steam units totaling 35.92 MW (net) firm capacity. Maui Electric deactivated two units to conform with our Curtailment Reduction Plan[27], but we can reactivate them in the event of a shortfall. The other two units were previously scheduled for retirement in 2019, however their retirement would have resulted in a reserve capacity shortfall of approximately 40 MW per year. To ensure enough capacity to meet demand, we obtained a National Pollutant Discharge Elimination System (NPDES) permit[28] valid through May 13, 2020 State of Hawai'i Department of Health (DOH) to allow Kahului Power Plant to continue operating provided we retire the units by November 13, 2024. We currently plan to retire the entire facility in 2022 assuming sufficient replacement resources (including DR and generation) are in operation by then.

Our Ma'alaea Power Plant has 15 diesel units and 4 gas turbines. They can be configured into two separate combined cycle systems supplying two steam turbines totaling 208.42 MW (net) of firm capacity. In 2014, we upgraded the generator controls on four of the diesel units to that they could be monitored and operated remotely. These upgrades enable us to better respond to system disturbances and system demands because of increased variable renewable resources on the system. We plan to modify one of the combined cycle systems, allowing it to operate at lower levels so that the grid can accommodate more renewable generation.

Our Hana Substation No. 41 has two diesel units totaling 1.94 MW (net) firm capacity.

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[26] Our 2016 AOS report noted that the peak demand recorded in 2015 and adjusted for standby load was 1,232 MW-net. This was 37 MW higher than the 1,195 MW-net peak demand forecasted for 2015. The report attributed this higher peak demand to higher than normal temperatures and humidity. The adjusted 2015 recorded peak is 69 MW higher than the 1,163 MW-net peak demand forecast for 2016.

[27] *System Improvement and Curtailment Reduction Plan* filed in Docket No. 2011-0092, September 3, 2013.

[28] The permit includes various conditions, including a compliance plan which identifies interim milestones to cease water discharge by 2024.

Moloka‘i has a centralized generating station with nine diesel internal combustion units and one diesel combustion turbine with combined capacity to generate 12.0 MW (gross) firm capacity. We recently received approval from the DOH to allow for lower minimum operating levels on the two baseload units to accommodate more renewable generation. We also scheduled generator control upgrades for 2016 to improve operation and troubleshooting of the generating units.

Lana‘i includes a centralized generating station with nine diesel units with 10.4 MW (gross) firm capacity. We have applied to the DOH to allow for the same generator control upgrades as on Moloka‘i. We also plan to operate a Combined Heat and Power (CHP) unit to provide baseload power; it’s expected to return to service in 2017.

Hawai‘i Electric Light

Hawai‘i Electric Light placed Shipman 3 and Shipman 4 on dry layup (inactive) on November 21, 2013, and retired them on December 31, 2015. The production and maintenance costs for the units were not cost effective compared with other generating units. Even without these units, the utility has sufficient generating capacity to provide adequacy of supply.

Dispatchable Generation Selection for Modernized Fleet

Even under an aggressive renewable build out plan, Hawai‘i will require dispatchable resources to meet the foreseeable demand as the fleet transitions to a 100% RPS portfolio. The following key parameters must be considered in the design of the 100% RPS plan.

An optimized fleet must be designed to ensure the lowest possible impact to the customer bill.

Customer electric demand must be met during the expansion of the renewable fleet to the 100% RPS targets.

- A cost effective balance must be achieved between the amount of utility scale renewables, storage and dispatchable generation to support the renewable fleet as it grows.

The dispatchable generation of the future must have the characteristics required to support an intermittent dispatch renewable fleet. The characteristics of this generation must include the following:

- Support the delivery of electricity and ensure grid stability during the build out and long term operations of all types of intermittent renewables to reach the 100% RPS goal for Hawai‘i.

- Minimize the total impact to customer bills from the addition of the generation including the lifecycle costs of the generation.
- Fuel flexibility to include the ability to burn natural gas and liquid fuel like biodiesel to maximize efficiency and allow participation in the 100% RPS plan.
- Reduce the emissions and its impact on the environment.

The Companies have considered all of the necessary components of a cost effective renewable plan, and will outline within this PSIP a method to develop a portfolio that meets them. The proposed modernization of the generation fleet would ensure reliability, facilitate renewable integration, and reduce costs to the customer. An evaluation of the future modernized generation revealed two types of dispatchable generation are needed:

- High Capacity Factor Generation
- Fast Start, Low Capacity Generation

The Companies evaluated potential candidates to meet the High Capacity Factor Generation need. The following screening criteria was applied:

- Lowest total (capital and operational) cost
- High efficiency to minimize fuel cost
- Fast start and load ramp to support renewables
- Low Emissions

The next step was to evaluate the various technology options:

- Advanced Combined Cycle Units – This technology has the lowest total cost, the highest efficiency while supporting fast start and ramp rates. The advanced combined cycle units have lower emissions that the other applicable technologies.
- Aeroderivative Combined Cycle Units – This is older technology that has higher total cost than an advance combined cycle due to the smaller size of the units. While it has fast start and ramp rates, the efficiency is lower due to the older technology and unit size.

The Advanced Combined Cycle Unit has the characteristics to support renewables while delivering low cost and low emissions.

A screening criteria was developed for selection of the best combined cycle configuration. Preliminary screening of various configurations revealed that the CC unit of approximately 300 to 350 MW had best overall savings for the customer. There are two options that were evaluated:

- Three combined cycle units, each with one combustion turbine, one heat recovery steam generator, supplying steam to one steam turbine combined cycle units (that is, 3 1x1 CC)

- One combined cycle unit with three combustion turbines, three heat recovery steam generators, and a single steam turbine (that is, 3x1 CC)

Total cost of evaluation of the two configurations revealed the 3x1 CC would save $136 million over the cost of 3 1x1 CC units. Contributing to that savings is a $48 million capital construction cost savings, a $21 million maintenance cost savings over the unit life and a $67 million fuel cost savings over the unit life due to more efficient heat rate of the 3x1 configuration versus the 3 1x1 configuration.

The combined cycle unit supports the use of biodiesel that will be required for compliance with the 100% RPS. The higher efficiency will lower the cost of energy generated from biodiesel by 30% as compared to utilizing biofuels in existing conventional steam units.

The combined cycle unit needs to demonstrate operational flexibility required to support a large renewable fleet. The 100% RPS fleet will require dispatchable generation to support the following needs:

- Quick response to a loss of resource (solar or wind) event. The combined cycle plant will need to start quickly with short notification of a cloud cover event. Although energy storage systems are being considered for initially responding to a large cloud cover event, the combined cycle plant would still be required to start quickly and replace that generation in order to minimize the size of any storage system.
- Ability to supplement the optimized BESS to ensure load demand is met in times of extended low resource.

An advanced 3x1 combined cycle unit is capable of starting and ramping quickly in several modes:

- Single, double or triple simple cycle combustion turbine operation: 15 minutes to full load for a single CT, 16 minutes for two, 17 minutes for three
- Single, double or triple combined cycle combustion turbine operation: 42 minutes to full load for 1x1, 43 minutes for 2x1, 44 minutes for 3x1
- Minimum Load 3x1 to Full Load operation 3x1: 35 MW/min

This capability would allow the modernized fleet to respond to drops in renewable resources while minimizing the size and cost of the BESS, and would eliminate the need for on-line reserve units to support system load transients. The combination of a cost effective storage system and a fast starting unit allows this unit to stay off line if not needed for load, resulting in significant fuel cost savings relative to less flexible generating alternatives. The startup times and ramp rates are significantly faster than the existing HECO fleet of thermal units, which require multiple hours for a hot startup and have load ramping rates ranging from 3–5 MW/min.

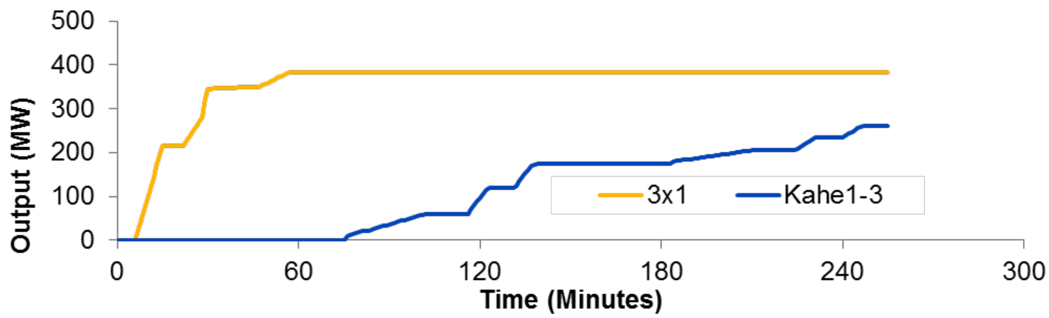

Figure D-39. Hot Start Kahe 1-3 versus 3 x1CC

Another important component in minimizing the cost of the modernization was to select the optimal location for the unit. Locating this unit on an existing site has many advantages including:

- Improved permitting schedule and lowering permitting risks
- Utilizing an existing source of cooling water
- Reduction in land improvement prior to construction

The Companies performed an evaluation of the existing HECO sites, and found the most optimal site for the new unit to be the Kahe Site. This site offered the opportunity to replace the generation of the aging Kahe 1, 2 and 3 units, which aligns with the plans for the future fleet. A key component of the selection criteria was that the Kahe site offered sufficient land to allow the existing units to remain running for the majority of the construction period. This is critical as the Loss of Load Probability studies for the HECO fleet show very small load margin through the late 2020s until the renewable fleet backed by storage can provide the fleet with more load certainty. The Kahe site also offers protection from the threat of a tsunami, as the constructible elevations at this site are above the tsunami plain. The transmission system at the Kahe site offers a cost effective solution for integrating the repowered Kahe unit into the O‘ahu grid.

Although the 3x1 CC plant is more fuel efficient than several 1x1 CC units, it was important to ensure that it was equal in flexibility. To ensure the units were flexible, and that the unit performed exactly like three separate units, some unique design features were assumed. These design features prevent the risk of losing the entire unit at one time from the grid. Specifically, the 3x1 CC would be designed so that any one combustion turbine failure will result in a load loss of only one-third of the unit. This removes the risk that the present HECO fleet has with the large single generator at AES of 180 MW. With the design being considered for the Kahe replacement generation, the greatest load loss will be 127 MW, similar to the largest existing unit at Kahe.

The design feature that allows this 3x1 CC plant to function like three 1x1 CC plants is the addition of an independent dump condensers for each combustion turbine train.

These individual condensers not only reduce the magnitude of the generation loss, as described above, it also allows the operation of the three combustion turbine trains during a steam turbine outage. This allows the availability of the 3x1 combined plant cycle generation to be significantly larger than that of a typical 3x1 combined cycle plant.

In summary, the addition of the Kahe replacement generation to the HECO fleet meets the criteria set forth by the Companies required to enable the fleet of the future to support the dispatchable needs of the 100% RPS fleet. This replacement generation option would meet the "High Capacity Factor" generation needs from now until 2030, and it would also be designed to meet the "Fast Start Low Capacity Factor" needs beyond 2030.

Unit Retirement Order Methodology

The production modeling analysis will include a determination of the timing of unit retirements. The purpose of this document is to describe the current initial methodology used to select the order of retirements by unit.

The current initial criteria for determining order of retirements includes operational flexibility (including the constraints imposed by environmental permits0, age, unit efficiency, and site staffing efficiencies.

Some of the unit characteristics are shown in Table D-75.

Unit	Type/Fuel	Capability		Year Commercial	Unit Heat Rate
		Gross MW	Net MW		
Kahe 1	Reheat Steam/LSFO	86	82.2	1963	
Kahe 2	Reheat Steam/LSFO	86	82.2	1964	
Kahe 3	Reheat Steam/LSFO	90	86.2	1970	
Kahe 4	Reheat Steam/LSFO	89	85.3	1972	
Kahe 5	Reheat Steam/LSFO	142	134.6	1974	
Kahe 6	Reheat Steam/LSFO	142	133.8	1982	
Waiau 7	Reheat Steam/LSFO	87	83.3	1966	
Waiau 8	Reheat Steam/LSFO	90	86.2	1968	
Total Base Load		812	773.8	Average Age	
Waiau 3	Non-Reheat Steam/LSFO	49	47	1947	
Waiau 4	Non-Reheat Steam/LSFO	49	46.5	1950	
Waiau 5	Non-Reheat Steam/LSFO	57	54.5	1955	
Waiau 6	Non-Reheat Steam/LSFO	56	53.7	1961	
Total Cycling Capability		211	201.7	Average Age	
Waiau 9	Simple Cycle CT	53	52.9	1973	
Waiau 10	Simple Cycle CT	50	49.9	1973	

CIP CT-1	Simple Cycle CT	113	112.2	2009	
Total Peaking Capability		216			

Table D-75. Hawaiian Electric Unit Characteristics

The order of retirement assumed for the cases including the Kahe replacement generation (Cases 2 and 4):

1. Honolulu 8 and 9, units are already de-activated
2. Kahe 1, 2, 3 together with the commercial operation of the Kahe replacement generation, the intake cooling water systems are required for replacement generation
3. Waiau 3, 4, because of age, low efficiency non reheat plant design
4. Kahe 4, because of staffing efficiencies, this unit shared a control room and multiple systems with Kahe 3; and operational impact, because of shared systems and stack structure, demolition of 1, 2 and 3 is not possible until K4 is retired
5. Waiau 5, 6 because of age, low efficiency non reheat plant design
6. Waiau 7, 8, because of age, improved efficiency reheat design over earlier Waiau units
7. Kahe 5, 6 are the newest, largest, and most efficient units in the fleet.

Here is the order of retirement assumed for the cases that do not include the Kahe replacement generation (Case 1 and 3):

1. Honolulu 8 and 9, units are already de-activated
2. Waiau 3, 4, because of age, low efficiency design and limited operational flexibility
3. Waiau 5, 6, because of age, low efficiency improved operational flexibility over Waiau 3, 4 because of reheat design
4. Waiau 7 and 8, for age, improved staffing efficiencies by retiring the last steam unit at Waiau
5. Kahe 1 and 2 because of age, improved efficiency over Waiau units, still limited operational flexibility
6. Kahe 3 and 4 because of age, improved efficiency over Waiau units, still limited operational flexibility
7. Kahe 5 and 6, as shown above

We plan to reevaluate the unit retirement order methodology shown above for our Updated PSIPs.

REPLACEMENT GENERATION

Kahe Generation Replacement

Because of the age of the existing generation fleet (the average age of the fleet on O'ahu is 51 years), modernization of the existing O'ahu generation fleet is one option being considered in the 2016 PSIP update. Specifically, a resource option available to the Company in the 2016 PSIP update is the replacement of Kahe Units 1–3 (approximately 50 years) with advanced combined cycle units, which would be installed at the existing Kahe site. Such combined cycle units could provide fast start and load ramp capabilities to support renewables, have high fuel efficiency and a low emissions profile, and utilize existing infrastructure to minimize community impact and further reduce costs.

Cost and Operating Assumptions for the 3x1 Advanced Combined Cycle Units

A Kahe modernization ("Kahe 7–10") could provide 383 MW at a capital cost of $717 MM (without AFUDC), or $1,870/kW and be online in 2021. Table D-76 summarizes the cost and key operating characteristics of the proposed 3x1 advanced combined cycle unit.

Unit Model	GE 6F.03 3x1CC
Total Cost without AFUDC ($ K)	$716,200
$/kW	$1,870
Net Sum Capability (MW)	358
Heat Rate @ Base (btu/kwh)	6965
Net Sum Capability with Wet Compression (MW)	383
Min Load CT Only (MW)	36
Min Load Combined Cycle 1x1 (MW)	64
Time to CT Base Load 221MW (min)	17
Fuel types	Gas/Oil/Bio

Table D-76. Costs and Operating Characteristics of the Kahe Advanced Combined Cycle Units

Benefits of the 3x1 Advanced Combined Cycle Units

Advanced combined cycle units have the operational characteristics required to support the variable nature of renewable generation and support the transition to 100% RPS.

Efficiency

A modernized fleet utilizing advanced combined cycle technology replacing existing units at Kahe would be more efficient and utilize significantly less fuel than the existing Kahe units. As the Figure D-40 demonstrates, the 3x1 combined cycle units would be 31% more fuel efficient at full load and 42% more efficient at minimum load, compared to the existing Kahe units.

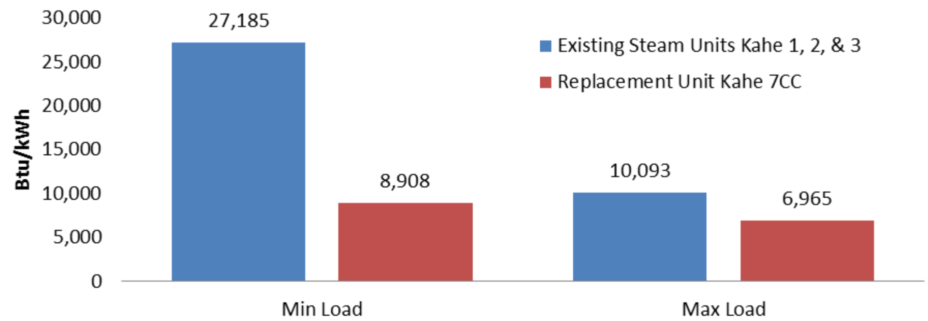

Figure D-40. Heat Rate Comparison: Existing Kahe Generation versus Replacement Combined Cycle

Improved Reliability

Advanced combined cycle units at Kahe would be more reliable than the existing Kahe units (Figure D-41).

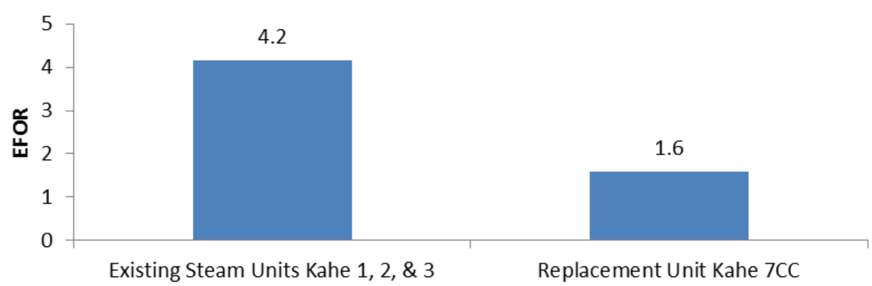

Figure D-41. EFOR of Existing Kahe Units versus Projected EFOR of Kahe 3x1 Combined Cycle

Faster Cold Start Ramp Rates

Advanced combined cycle units have fast start and load ramping capabilities to respond to rapid or prolonged periods of variable renewable generation. The advanced combined cycles can be at minimum load in 14 minutes and be at full load in 44 minutes. This characteristic is vital for reliability to support a system with high renewable penetration and allows for a more rapid and increased level of renewable integration.

Time (hrs)	2	4	6	8	10	12	14	16	18	20	22	24
3x1 CC (MWs)	321	358	358	358	358	358	358	358	358	358	358	358
Steam Units (MWs)	0	0	0	0	0	5	40	70	100	100	125	132

Table D-77. Cold Start Ramp Rates: Existing Kahe Units versus Kahe 3x1 Combined Cycle

Reduced Emissions

One of the benefits associated with a 100% RPS target is reduced environmental emissions from the Hawaiian Electric generation system. Modernizing the existing fleet with advanced combined cycles would enhance those environmental benefits further. As Table D-78 shows, the addition of advanced combined cycles to the generation portfolio significantly reduces emissions compared with a portfolio comprised primarily of existing steam generation, even when both portfolios are fueled by liquid fossil fuels.

	SO2 tons	NOx tons	PM tons	CO2 tons
Reference Scenario	14.1 k	24.6 k	5.1 k	4.7 Mil
Modernization only	8.5 k	14.8 k	2.1 k	4.4 Mil

Table D-78. 2023 Emission Rates of Existing Fleet versus Replacement Generation

The environmental benefit would be immediate upon operation of the advanced combined cycle units and remain during the transition to a 100% RPS.

The reductions of CO_2, SO_2, NOx and PM through the modernization result in several environmental benefits. CO_2 reductions support the state's goal to reduce greenhouse gas emissions that contribute to climate change impacts such as increased temperatures and sea level rise. Combining the lower emission profile of advanced combined cycle units with use of natural gas instead of oil as a fuel source compounds this environmental benefit. CO_2 content in natural gas is approximately 33% less than in the low sulfur fuel oil currently used in the Hawaiian Electric units. SO_2 emissions reduction resulting from the use of natural gas will assist the state to reach attainment status under the 2010 one-hour SO_2 National Ambient Air Quality Standards. SO_2 emissions are attributed to respiratory illnesses and acid rain formation. NOx emissions are the primary contributor to the formation of ozone (smog) that can cause respiratory illness. Particulate Matter (PM) results in visible emissions (smoke) observable by local residents and business near the plant. PM emissions also include the Hazardous Air Pollutant metals that may increase the risk of cancer and respiratory illness.

In addition to reducing the criteria pollutants of CO_2, NOx, SO_2, and PM, modernizing the fleet and adding advanced combined cycle units burning natural gas will result in significant health benefits through the reductions of other hazardous air pollutants (HAPs) emissions such as:

- Metals, including mercury (Hg), arsenic, chromium, and nickel
- Acid gases, including hydrogen chloride (HCl) and hydrogen fluoride (HF)
- According to EPA these pollutant emissions from oil firing are linked to cancer, respiratory illnesses and IQ loss.

Minimizing the Cost of New Generation

The most optimal site for replacing existing generation is at the existing Kahe Generating Station. This site offers the opportunity to repower the aging Kahe 1, 2 and 3 units, which aligns with the plans for the future fleet. The Kahe site also offers sufficient land to allow the existing units to remain running for the majority of the construction period. This is critical as reliability studies for the Hawaiian Electric fleet show very small load margins during that time period. The Kahe site also offers protection from the threat of a tsunami, as the constructible elevations at this site are outside the tsunami inundation zone. Finally, the transmission system at the Kahe site offers a cost effective solution for integrating the repowered Kahe unit into the O‘ahu grid. The advanced combined cycle unit cost information used in the PSIP Update modeling is based upon estimates to build such a 383 MW combined cycle unit at Kahe Generating Station as described above.

Figure D-42. Artist Rendering of Possible Kahe 3x1 Combined Cycle Plant with Removal of Kahe 1–3

Military Base Microgrids

Hawaiian Electric will be seeking replacement generating capacity for the island of O‘ahu as existing power plants reach retirement age and as new flexible (and efficient) generation technology becomes necessary to integrate large amounts of as-available energy resources on the island grid. The Marine Corps and the Navy are seeking enhanced energy security for their bases and to the extent that this can be accomplished without significant capital investment by the Department of Defense (DoD), they are interested in partnering with Hawaiian Electric to do so. There are potential synergies to these needs that could be aligned to develop mutually beneficial solutions to the benefit of all O‘ahu customers.

The Air Force has similar goals and requirements to the Navy/Marine Corps. Because of the consolidation of Hickam Air Force Base and Naval Base Pearl Harbor into JBPHH (which is administered by the Navy), meeting the Navy’s goals for JBPHH will also satisfy the Air Force’s goals.

Hawaiian Electric's goals include:

- Satisfying our customers' needs for cost-effective energy solutions, including the DoD's energy security needs.
- Developing new flexible generating assets that can respond to the variability of as-available energy resources (for example, photovoltaics and wind power), thus enabling higher penetration levels of those variable resources.
- Enhancing the company's ability to meet the 100% RPS goals by investing in technologies that are capable of using renewable fuels (that is, biofuels).
- Improving island-wide energy resiliency, which includes fuel flexibility and smaller, more geographically dispersed generators.
- Improving grid-wide efficiency.
- Improving the response capability of First Responders in an island-wide emergency such as a natural disaster.
- Leveraging low cost, limited use lands for which existing zoning will allow for installation of new generation to minimize development costs.
- Seek Military service funding and execute NEPA EIS process, to demonstrate service commitment to project.

Hawaiian Electric understands the DoD's goals to include:

- Enhanced energy security and resiliency for its bases, including Marine Corps Base Hawaiʻi (MCBH) and JBPHH, while minimizing capital costs by leveraging public-private partnerships with utilities.
- Added opportunities to increase renewable energy generation on DoD installations.
- Reduced energy costs.

Marine Corps Base Hawaiʻi (MCBH) Microgrid Concept

To provide the services desired by the Marine Corps, it is only practical that generation be located on Marine Corps Base Hawaiʻi. In addition to meeting the needs of the Marines, adding generation on the windward side of the island can provide resiliency benefits to customers in that area. Therefore, this is the only concept contemplated for this branch of service.

The addition of generation would create a microgrid for the military base where the new generation and existing base resources (such as rooftop PV) has sufficient capacity and grid controls to safely and reliably serve the Base's load.

Site Characteristics, Restrictions and Needs

The Marine Corps previously identified a suitable site on MCBH (Figure D-43) for a replacement generating station near the existing Hawaiian Electric substation that feeds the base. The size of the potential generating station site is approximately 4.8 acres.

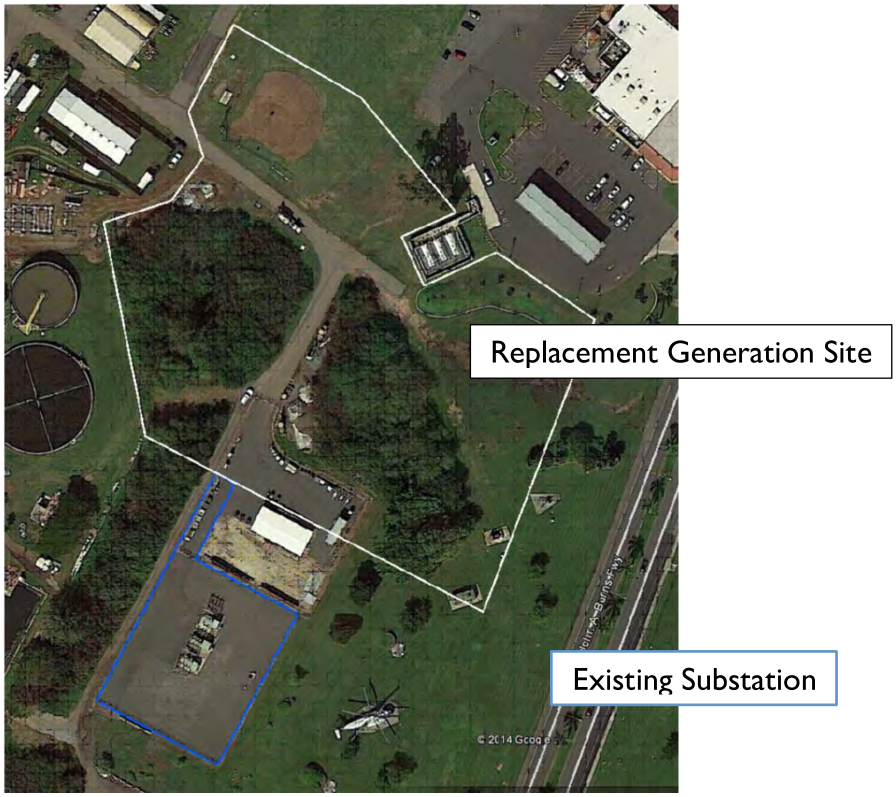

Figure D-43. MCBH Site for Possible Replacement Generation

Based on thermal limitations of the existing 46kV sub-transmission system feeding the base as well as the need to keep exhaust stacks less than 100 ft. above ground level (because of air space restriction associated with nearby helicopter operations), it appears that 54MW is the maximum size generating station this site could practically accommodate.

Furthermore, each of the two 46kV sub-transmission feeds is individually limited to 30MW. Therefore, 30MW would be the maximum size for any individual unit at this site.

No interconnection requirement study has been completed for interconnection at this location and could result in further restriction of project size.

The peak load of MCBH is approximately 16MW and the intent of a project on this site is to be able to serve the entire peak with one generating unit out of service for maintenance (N-1 design criteria).

A preliminary air permit analysis indicates that 54MW of reciprocating engines with 100 feet tall stacks (3 into 1) can be installed in compliance with all air regulations.

Generating Unit Selection and Project Size

Based on the N-1 criteria, Table D-1 shows the relationship between the number of units and the minimum size of each generating unit.

Number of Generating Units	Minimum Size Per Generating Unit for a 16MW Peak Load w/ N-1 Criteria	Total Project Capacity
2	16.0 MW	32.0 MW
3	8.0 MW	24.0 MW
4	5.3 MW	21.3 MW
5	4.0 MW	20.0 MW

Table D-79. Number versus Size of Proposed MCBH Generating Units

Table D-1 indicates the site cannot only accommodate enough capacity to meet the N-1 criteria, but that additional units could be placed at this site to satisfy a more robust criteria or to provide additional energy resiliency for off-base customers.

Previous analysis done for Maui Electric indicated that medium speed reciprocating engines for a station of this size are more cost-effective than using combustion turbines. However, the analysis is dependent on expected capacity usage of the project. Therefore, a specific analysis for O‘ahu should be conducted to determine the most cost-effective technology for this site.

Of the two engine sizes that Wärtsilä offers (9MW and 17MW), either could satisfy the design criteria. However, for this size of a project, the 9MW engine is expected to be more cost-effective and to provide better resiliency and power restoration capability. Thus, if Wärtsilä engines are chosen for this site, the project would use either the 20V32 (liquid-only) or the 20V34DF engine (liquid and gas). In either case is would result in a minimum project size of 27MW.

Proposed Project Strategy

Based on Hawaiian Electric’s unique and sole capability to deliver energy security to MCBH through integrated generating station and grid operations, the Marine Corps would select Hawaiian Electric as their sole partner for an energy security project on the selected site. Hawaiian Electric, with the support of the Marine Corps, would request from the Public Utilities Commission a waiver from its Framework for Competitive Bidding, based on the Marine Corps’ stated requirement to work with the utility to meet military needs.

Hawaiian Electric would lease the project site at little to no cost for the life of the project and design, permit, finance, construct, own, and operate a new, up to 54MW firm generating station located on the site. The generating station would normally be dispatched to meet grid-wide demands from all Hawaiian Electric customers.

Under conditions identified in the lease, Hawaiian Electric would provide energy security guarantees such that the Marine Corps would gain significantly enhanced energy security for MCBH. These guarantees by Hawaiian Electric would provide the

Marine Corps in-kind consideration in lieu of monetary rent payments for the life of the project.

In return for the enhanced energy security, the Marine Corps would contribute to the project with land and other contributions as deemed appropriate for the value of the energy security guarantees provided. The value of the land and other contributions to the project would reduce project costs, thereby saving our customers money compared to siting a similar project at a non-military location.

Joint Base Pearl Harbor–Hickam (JBPHH) Microgrid Concept

To provide the services desired by the Navy, two concepts are being considered: 1) locating a microgrid on base at JBPHH; or 2) installing a power barge at the Waiau Generating Station that could either be interconnected to JBPHH or temporarily relocated to JBPHH under emergency conditions.

The addition of generation would create a microgrid for the military base where the new generation and existing base resources (such as rooftop PV) has sufficient capacity and grid controls to safely and reliably serve the Base's load.

Site Characteristics, Restrictions and Needs

The Navy has not identified a desired and suitable site at JBPHH for installation of a new generating station. Hawaiian Electric, however, proposed a site. Hawaiian Electric, however, proposed the site shown in gray Table 1-1in Figure D-44.

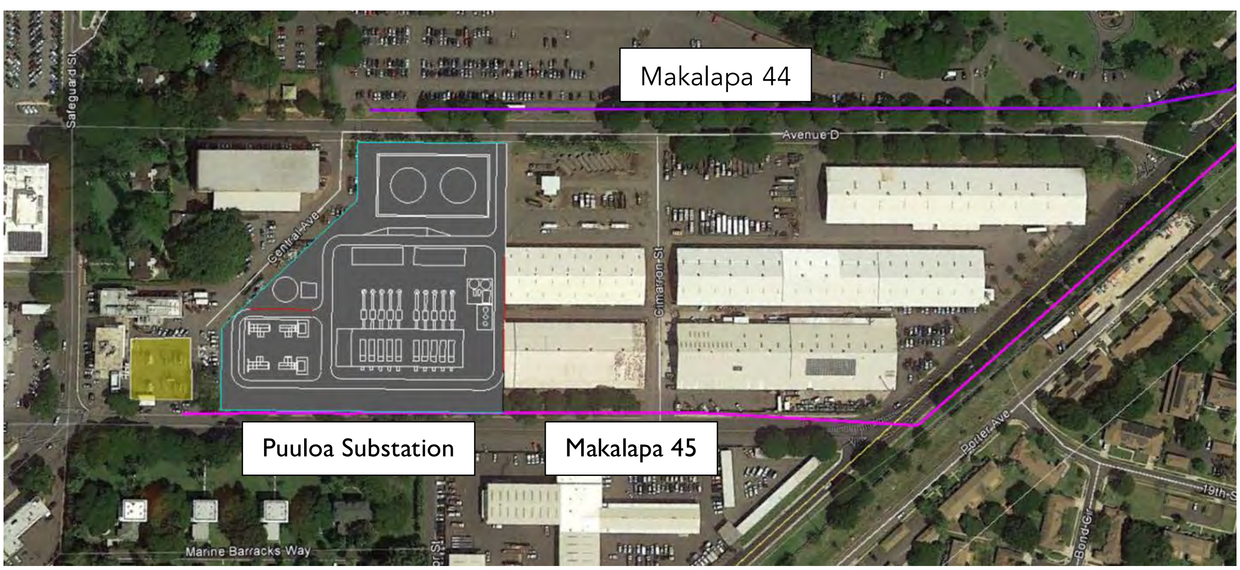

Figure D-44. JBPHH Site for Possible Replacement Generation

Based on thermal limitations of the existing 46kV sub-transmission system feeding the base, it appears that 96MW is the maximum size generating station this site could practically accommodate.

Furthermore, each of the two 46kV sub-transmission feeds is individually limited to 48MW. Therefore, 48MW would be the maximum size for any individual unit at this site.

No air permit analysis has been done yet for this site and could result in further restriction of project size.

No interconnection requirement study has been completed for interconnection at this location and could result in further restriction of project size.

The peak load of JBPHH is approximately 60MW and the intent of a project on this site is to be able to serve the entire peak with one generating unit out of service for maintenance (N-1 design criteria).

Generating Unit Selection and Project Size

Based on the N-1 criteria, Table D-80 shows the relationship between the number of units and the minimum size of each generating unit.

Number of Generating Units	Minimum Size Per Generating Unit for a 60MW Peak Load w/ N-1 Criteria	Total System Capacity
4	20.0 MW	80.0 MW
5	15.0 MW	75.0 MW
6	12.0 MW	72.0 MW
7	10.0 MW	70.0 MW
8	8.6 MW	68.6 MW
9	7.5 MW	67.5 MW

Table D-80. Number versus Size of the Proposed JBPHH Generating Units

Table D-80 indicates the site cannot only accommodate enough capacity to meet the N-1 criteria, but that additional units could be placed at this site to satisfy a more robust criteria, or to provide additional energy resiliency for off-base customers.

No analysis has been done to determine the most cost-effective technology to use for this location (reciprocating engines or combustion turbines). However, based on previous analysis done for Maui Electric, it is anticipated that medium speed reciprocating engines would be the lowest overall cost choice.

Of the two engine sizes that Wärtsilä offers (9 MW and 17 MW), either could satisfy the design criteria. However, for this size of a project, the 9 MW engine is expected to be more cost-effective. Thus, if Wärtsilä engines are chosen for this site, the project would use either the 20V32 (liquid-only) or the 20V34DF engine (liquid and gas). In either case this would result in a minimum project size of 72 MW.

Proposed Project Strategy

Based on Hawaiian Electric's unique and sole capability to deliver energy security to JBPHH through integrated generating station and grid operations, the Navy would select

Hawaiian Electric as their sole partner for an energy security project on the selected site. Hawaiian Electric, with the support of the Navy, would request from the Public Utilities Commission a waiver from its Framework for Competitive Bidding, based on the Navy's stated requirement to work with the utility to meet military needs.

Hawaiian Electric would lease the project site for the life of the project and design, permit, finance, construct, own, and operate a new, up to 96MW firm generating station located on the site.

The generating station would normally be dispatched to meet grid-wide demands from all Hawaiian Electric customers.

Under conditions identified in the lease, Hawaiian Electric would provide energy security guarantees such that the Navy would gain significantly enhanced energy security for JBPHH. These guarantees by Hawaiian Electric would provide the Navy in-kind consideration in lieu of monetary rent payments for the life of the project.

In return for the enhanced energy security, the Navy would contribute to the project with land and other contributions as deemed appropriate for the value of the energy security guarantees provided. The value of the land and other contributions to the project would reduce project costs, thereby saving our customers money compared to siting a similar project at a non-military location.

Waiau Power Barge Concept

Project Concept

Independent of any military considerations, Hawaiian Electric has identified that the waters of Pearl Harbor immediately adjacent to Hawaiian Electric's Waiau Power Plant are ideal for a floating power plant ("power barge"), and that this concept could result in a very cost-effective method to provide replacement capacity for O'ahu. Figure D-1 shows a three dimensional rendering of one possible configuration at the proposed site.

Figure D-45. Artist Rendering of Possible Power Barge at the Waiau Generation Station

The power barge concept presents three areas of potential savings compared to land based generating stations at other sites (including JBPHH). First, the installed costs of a power barge are lower than any land based construction in Hawai‘i, since the entire station would be built in a shipyard and shipped as a single unit. The on-site construction would be limited to the mooring system and the interconnections for utilities and power. Second, a power barge at the proposed location could utilize existing infrastructure at Waiau Power Plant. Third, the delivery schedule for a completed power barge is less than for a comparable facility built on site, reducing project costs.

Another potential advantage of a power barge is that it could be designed to be capable of moving between islands to provide emergency power and increase state-wide resiliency. This concept has not been studied, but could prove worthy of consideration if it broadens stakeholder support for the project. Such a capability would require additional systems and capabilities onboard the barge, and additional infrastructure on each island where the barge could be deployed. It would also have company and state policy considerations, which would require the support of state and county governments, and possibly Kauai Island Utility Cooperative (KIUC). Project cost allocations associated with these additional capabilities would also have to be determined.

Two types of power barge have been studied, RICE units and simple-cycle combustion turbines (CT). For the purposes of the study, 100MW nominal capacity barges were assumed, although the barge could be larger or smaller based on the outcome of air permitting and interconnection analyses. Barge comparison results are summarized in

Table D-3. Based on the analysis, the RICE barge appears to be the better solution for Hawaiian Electric than the turbine barge.

Type	Total Cost	Net Heat Rate (Btu/kWh HHV)
RICE	$160M	8,507
CT	$180M	8,951

Table D-81. Waiau Power Barge Comparison

Although the Waiau Power Barge concept was initiated to meet Hawaiian Electric needs, because of the close proximity of Waiau Power Plant to JBPHH, Hawaiian Electric is discussing with the Navy the possibility of using the power barge concept to fulfill the Navy's energy security needs as well. In a situation in which the Navy requires a direct feed of electrical power, this concept could take one of two forms:

- The barge could be re-located to a temporary mooring at JBPHH, and connected directly to the base electrical infrastructure.
- The barge could remain in place, but divert power to JBPHH via a direct connection using overhead or underwater cabling.

The peak load of JBPHH is approximately 60 MW. Since the overall capacity of the barge would be determined by Hawaiian Electric's capacity needs and not the Navy's needs alone, a minimum barge capacity of 100 MW is likely to be required. If the Waiau Power Barge concept were selected to meet the Navy's energy security needs, the project would also need to be able to serve the entire JBPHH peak with one generating unit out of service for maintenance (N-1 design criteria). The 100 MW RICE barge would incorporate six 17MW units, which would satisfy this criterion. The 100 MW CT barge, as analyzed, has a single 100 MW CT, which would not. Other combinations of smaller CT units could be considered, but in general this would increase the cost and the heat rate of the CT barge option, thereby making it even less competitive versus the RICE barge. Therefore, the RICE barge would be a better choice than the CT barge to meet the Navy's energy security needs.

Proposed Project Strategy

If the Waiau Power Barge is only considered as a Hawaiian Electric project for replacement capacity, it could be included as a competitive proposal to an open RFP for new generation, as outlined in the Framework for Competitive Bidding. If the barge serves as a state-wide emergency and resiliency asset serving a government need, a waiver from the Framework may be justified. Furthermore, if the Navy agreed that the power barge would meet their energy security needs, the project would meet several criteria under which a waiver would justifiable. The remainder of this strategy assumes this case.

Based on Hawaiian Electric's unique and sole capability to deliver energy security to JBPHH through integrated generating station and grid operations, and Hawaiian Electric's existing Waiau Power Plant located on Pearl Harbor, the Navy would select Hawaiian Electric as their sole partner for an energy security project. Hawaiian Electric, with the support of the Navy, would request from the Public Utilities Commission a waiver from its Framework for Competitive Bidding, based on the Navy's stated requirement to work with the utility to meet military needs (and also potentially on the project's unique capability to move inter-island as a "power supply needed to respond to an emergency situation").

Hawaiian Electric would lease the project site for the life of the project and design, permit, finance, construct, own, and operate a new, 100MW or more RICE power barge. (N.B. the requirements for, and cost of, a lease of Pearl Harbor waters are not developed, but an preliminary estimate is $150k/year)

The Navy would fund project costs that solely support the project's ability to meet the Navy's specific energy security requirements. If the barge will be deployable to other islands, cost sharing arrangements for project costs that are required for this capability would be negotiated by stakeholders.

The power barge would normally be dispatched to meet grid-wide demands from all Hawaiian Electric customers.

Under conditions identified in the lease, Hawaiian Electric would provide energy security guarantees such that the Navy would gain significantly enhanced energy security for JBPHH. These guarantees by Hawaiian Electric would provide the Navy in-kind consideration in lieu of monetary rent payments for the life of the project. If deployable to other islands, the barge would only do so after Hawaiian Electric ensured that JBPHH's demand is being served by the grid.

In return for the enhanced energy security, the Navy would contribute to the project with land and water lease rights, and other contributions as deemed appropriate for the value of the energy security guarantees provided. The value of the Navy contributions to the project would reduce project costs, thereby saving our customers money compared to siting a similar project at a non-military location.

Existing PPAs

Since we filed our PSIPs in 2014, we have experienced changes in assumptions for some of our Independent Power Producers: AES Hawai'i, Kalaeloa Energy Partners (KPLP), Hamakua Energy Partners (HEP), Hu Honua, and Hawaiian Commercial & Sugar (HC&S). We have also updated our plans for modifying existing units to burn gas, and changed operations to comply with environmental requirements.

AES Hawai'i Generating Unit

The 2016 PSIP analysis assumes that our power purchase agreement (PPA) with AES Hawai'i will not be renewed when it expires on September 1, 2022. Our ability to integrate more renewable generation onto the grid in the coming decades will be improved without a large, inflexible single generator such as AES on the system. The unit provides relatively little ancillary services to the system. Under the current PPA, AES provides a large block of coal-fired generation that Hawaiian Electric must accept. Without this constraint, more renewable energy can more easily be integrated onto the system.

On January 22, 2016, we filed an application with the Commission seeking approval of Amendment No. 3 to our existing PPA with AES Hawai'i. If this amendment is approved by the Commission, AES would provide an additional 9 MW of firm, dispatchable capacity and associated energy from the existing power plant. As AES provides the lowest cost energy to the system, this addition helps lower customer bills in the near term. The amendment will not extend the term of the PPA, as the addition of higher levels of variable renewable energy demands a higher level of generation flexibility than can be accomplished with AES on the system.

Kalaeloa Energy Partners (KPLP)

The Kalaeloa Plant's combined cycle design has the operational flexibility required to support the needs of the renewable fleet. The existing PPA for the Kalaeloa Plant is restrictive; it does not allow the Companies to operate the plant with the flexibility that will be required in the future. These operating restrictions include limitations on startup times, ramp rates, and minimum load. In addition, the unit's fuel source is inflexible; we would like to have more fuel sources available to minimize cost to the customer. The ability to operate this plant to more closely align with design limits would enable the facility to better meet the support needs of the future renewable fleet.

Options to remove these restrictions are ongoing and could consider several alternatives. Should the PPA expire and KPLP cease to provide firm capacity, we might seek additional capacity by deferring future deactivation of units, increasing DR programs, optimizing maintenance schedules, reactivating currently deactivated units, or acquiring additional firm capacity.

The PSIP assumes the same operational flexibility of the KPLP plant after the end of the existing PPA. This assumption, however, could change after filing this PSIP Update Interim Status Report.

Hamakua Energy Partners (HEP)

On February 12, 2016, Hawaiian Electric and Hawaiʻi Electric Light have submitted an application requesting that the Commission issue an order by no later than November 1, 2016 approving the purchase of the 60 MW dual fuel combined cycle HEP plant and its related assets. The application describes the purchase terms and the benefits to our customers.

HEP is a reliable, flexible firm capacity resource that continues to be critical in meeting adequacy of supply and system security needs with reasonable energy costs.

Acquiring and continuing to operate HEP provides Hawaiʻi Electric Light customers an efficient and reliable source of electric power. Company ownership enables us to improve customer benefits. The PPA the Covered Source Permit constrains unit commitment to one start per unit per day. Under the PPA, a started unit cannot be taken offline unless it will not be needed later in the day. The economic dispatch is based upon the contractual heat rate, which results in a higher energy rate than the equipment heat rate.

Company acquisition would allow economic dispatch of the plant without the startup restrictions based on the true heat rate, and also remove the fixed contractual capacity charge. The impact removed charges will result in a $74,100,000 savings over the life of the plant (assuming operation to 2040). In addition, we anticipate economic and system reliability improvements by adding a steam bypass system (which HEP was unwilling to install at their expense). This addition will permit faster startup time in simple cycle, providing improve system benefits associated with increasing variable renewable energy, and reducing startup costs.

The HEP plant can be converted to burn clean, cheaper LNG, which supports the transition to 100% renewables. Ownership enables the Company to have direct control on the potential for this fuel conversion and equipment maintenance to better meet future system needs and our customers.

Adding the Hamakua Combined Cycle Plant to our fleet will also provide valuable operational and maintenance synergies. For example, the Keahole unit on Hawaiʻi Island and the two Maʻalaea units in Maui also run the same GE LM2500s in a combined cycle plant configuration.

Hu Honua

Hu Honua is the next planned renewable energy resource addition on the Hawaiʻi Electric Light system. However, Hu Honua has missed major project milestones under the terms of its power purchase agreement. As a contingency plan and in order to inform on resource options, the PSIP analysis does not assume Hu Honua as being available.

Hawaiʻi Electric Light, in response to Order No. 33516, will file a response by February 16, 2016 describing the status of Hawaiʻi Electric Light and Hu Honua's efforts in completing the milestone events set forth in Attachment B of the PPA dated May 3, 2012, as amended; and any other relevant information.

Hawaiʻi Island Geothermal Request for Proposal (RFP)

The only project bidder that met the minimum threshold requirements for selection to the Final Award Group in the Geothermal RFP has determined that developing the proposed geothermal project would not be economically and financially viable. All received bids were for projects located in East Hawaiʻi. Given this, Hawaiʻi Island geothermal is not a base assumption in the analysis.

Hawaiʻi Electric Light has always been and remains committed to the development of geothermal on the island of Hawaiʻi if it is in the best interest of its customers. While Hawaiʻi Electric Light is disappointed that the Geothermal RFP did not result in viable geothermal project, we remain hopeful that geothermal generation can be a viable option on Hawaiʻi Island in the future and can help Hawaiʻi meet its 100% renewable energy goal while lowering customer bills, reducing Hawaiʻi's dependence on fossil fuels, allowing for continued integration and management of variable renewable resources within the Hawaiʻi Electric Light system and maintaining reliability of service.

Hawaiian Commercial & Sugar (HC&S) Closure

The Maui Electric analysis assumes HC&S contributing 4 MW of firm capacity in 2016, and no generation in 2017 and beyond.

Maui Electric's current PPA with HC&S allows us to schedule up to 4 MW of firm capacity during certain months of the year. The PPA terms continued through December 31, 2017. On January 6, 2016, however, HC&S issued a Notice of Termination of Power Purchase Agreement, which specified that HC&S's contribution to the Maui Electric power grid would end on January 6, 2017.

Maui Electric will explore other grid-related impacts associated with the PPAs termination. Maui Electric will continue discussions with HC&S about potential energy partnership opportunities that may result from future HC&S operations, including a locally-sourced biofuel supply.

ENVIRONMENTAL CONSIDERATIONS

Updated MATS and NAAQS requirements directly affect Hawaiian Electric steam generating units.

Mercury and Air Toxics Standard (MATS) Compliance

The O‘ahu power grid currently generates approximately 1,700 MW of firm capacity. A variety of sources contribute to this generation capacity. The two largest generating stations are Kahe (635 MW) and Waiau (480 MW). Both plants comprise mostly steam generating units that currently fire low sulfur fuel oil (LSFO)— the fuel remaining after the lighter petroleum products (such as gasoline, diesel fuel, and jet fuel) are refined from crude oil.

In April 2016, these steam units are subject to the EPA’s new MATS requirements. The plants as a whole must comply with more stringent National Ambient Air Quality Standards (NAAQS) in 2024.

MATS requires Hawaiian Electric to control and measure particulate matter (PM) emissions as well as fuel moisture content as surrogates for reducing hazardous air pollutants (including heavy metals and acid gases) from its oil-fired steam generating units by April 2016. The EPA’s MATS originally required Hawaiian Electric to reduce emissions of hazardous air pollutants-HAPs (including heavy metals and acid gases) from its oil-fired steam generating units by April 2015.

On November 6, 2013, Hawaiian Electric obtained from the State Department of Health (DOH) a one-year extension[29] and now has until April 16, 2016, to comply with MATS.[30] To prepare for this new compliance date, Hawaiian Electric, in cooperation with NextEra Energy, conducted emissions testing for each steam unit on O‘ahu subject to MATS. Tests involved measuring PM emissions to confirm the effectiveness and repeatability of potential MATS solutions. Testing throughout 2014 and 2015 have allowed Hawaiian Electric to collect data to confirm the accuracy of the MATS solution chosen.

As announced in the Companies’ January 2016 Update of Fuels Master Plan (FMP), Hawaiian Electric’s preferred compliance solution is to fire a 70/30 blend of LSFO and low sulfur diesel (LSD) at Kahe 5 and Kahe 6, but to continue using 100% LSFO at Kahe 1–4 and Waiau 3–8. This is quite a departure from the original concern that all units

[29] The MATS compliance date is set forth in Title 40 of the Code of Federal Regulations (CFR), Part 63, Subpart UUUUU, National Standards for Hazardous Air Pollutants: Coal-and Oil-Fired Electric Utility Steam Generating Units.

[30] Only Hawaiian Electric’s units are subject to MATS. Hawaiian Electric will begin burning a MATS-compliant fuel in January 2016 in order to comply with the April 16, 2016 deadline.

would have to burn a more expensive 70/30 or 60/40 MATS fuel. (The January 2016 FMP update details Hawaiian Electric's MATS-compliant solutions.[31])

PM emissions from the existing steam units will be significantly lower when using natural gas derived from LNG as compared to LSFO or LSD. LNG will therefore be a MATS-compliant fuel. If LNG materializes, then LNG will likely be a primary fuel in the existing steam units, with the MATS-compliant 70/30 oil solutions as secondary, back-up fuels.

MATS Fuel Assumptions

The Companies determined fuel blends to meet the MATS particulate matter emission standard of 0.03 pound per MMBtu through a structured testing protocol. The 2014 PSIPs stated that "based on field test results to-date, Hawaiian Electric observes that blending the equivalent of approximately 40% to 50% diesel into the current low sulfur fuel oil provides compliance with the MATS PM standard." The 2014 PSIP assumed a blend of 60% LSFO and 40% LSD.

Continued MATS particulate matter testing (which optimized operating parameters and improved maintenance practices) determined that the compliance fuel blend would be:

- 100% LSFO for Kahe 1–4.
- A blend of 70% LSFO and 30% (LSD) for Kahe 5–6.
- 100% LSFO for Waiau 3–8.

The MATS rule has no impact on steam units under 25 MW. The Maui Electric and Hawai‘i Electric Light steam generating units are not affected by MATS.

National Ambient Air Quality Standards (NAAQS) Compliance

Our current plans to use LSFO for MATS compliance might become moot when the new rules for NAAQS become effective for existing units. Absent the use of LNG, burning 100% LSFO would be our best-case option for complying with the new NAAQS requirements. The worst-case option (that is, highest cost) would be a blend of 40% LSFO and 60% LSD. Our analysis uses this conservative 40/60 blend.

The Clean Air Act (CAA) requires the EPA to set NAAQS for pollutants considered harmful to public health and the environment. The six "criteria" pollutants are carbon monoxide (CO), lead, nitrogen dioxide (NO_2), ozone, PM, and sulfur dioxide (SO_2). The CAA also requires the EPA to review the NAAQS every five years and to revise it to reflect the latest scientific information on the impacts of air pollution on public health

[31] The January 30, 2016 FMP Update was filed as Attachment D to the quarterly report filed in Docket No. 2014-0217 on January 29, 2016.

and the environment. In 2010, EPA revised the NAAQS for SO_2, NO_2, and $PM_{2.5}$, making compliance more stringent.

Based on our preliminary analysis, the new SO_2 standard poses the greatest compliance challenge. Even though NAAQS requirements for existing units have extended from 2017 to 2024, we had to consider a variety of compliance options when strategizing our long-term fuel procurement assumptions and solutions for our Updated PSIPs and assumptions necessary to input into its revised PSIP.[32] Lowering SO_2 emissions to the required levels could be achieved by either switching to a lower sulfur fuel, or by installing air quality control equipment (backend controls). These backend controls, however, are estimated to represent approximately $900 million in capital expenditures, and as such, were not considered to be a viable solution. Thus, the most cost effective way to comply with future NAAQS requirements is to use a fuel that meets the requirements.

We believe the worst-case (that is, highest cost) is to use a 40/60 blend of LSFO and LSD. We hope that a smaller percentage of LSD (potentially even 0%) will meet compliance requirements. Using LNG that costs less than an oil-based compliance option would result in cost savings to customers. LNG has emerged as a viable option that will comply with air emission standards while also substantially lowering fuel costs. Adding LNG capability to existing generating stations is relatively straightforward.

If LNG is successfully delivered to Hawaiʻi and used in our designated generating units, we will reserve the oil-based option as a backup solution for complying with MATS and NAAQS should the supply and delivery of LNG be interrupted. Modifications proposed for Kahe 5 and Kahe 6 will allow dual firing of MATS or NAAQS compliant fuels along with LNG, which is critical for resiliency and security.

MODELING INPUT ASSUMPTIONS

Forecasts

The purpose of the load (or peak demand) and sales (energy) forecasts in a planning study is to provide the energy requirements (in GWh) and peak demands (in MW) that must be served by the Company during the planning study period. Forecasts of energy

32 The Fuels Master Plan (FMP) is filed semi-annually in Docket No. 2012-0217; the plan continually updates the Companies' fuel strategies and procurement timelines. The January 2013 FMP discusses NAAQS in detail, however once the EPA pushed back the NAAQS deadline, FMPs after January 2013 focused more on near-term MATS compliance, and not NAAQS. With the filing of this Application, NAAQS discussion is reemerging in fuel procurement planning.

requirements and peak demand must take into account economic trends and projections and changing end uses, including the emergence of new technologies.

This forecast is the beginning of an iterative process that will determine varying levels of customer adoption of DER and participation in DR programs to achieve system optimization.

Sales and Peak Demand Projections Methodology

The Company develops sales and peak demand forecasts on an annual basis and utilizes the latest information available at the time the forecast is prepared. The sales and peak forecast adopted in May 2015 was used as the starting point for the sales and peak demand analysis, as it was the most currently available forecast. The DG projections in the May 2015 forecast were then updated to reflect modifications to the existing Company tariffs identified in Decision and Order No. 33258 in Docket No. 2014-0192 received in October 2015. This order approved revised interconnection standards, the closing of the Net Energy Metering program and new options for customers aimed at continuing the growth of rooftop solar while ensuring safe and reliable service.

The methodology for deriving net peak demand and energy requirements to be served by the Company begins with the identification of key factors that affect load growth. These factors include the economic outlook, analysis of existing and proposed large customer loads, and impacts of customer-sited technologies such as energy efficiency measures and customer-sited distributed generation (DG-PV). Impacts from emerging technologies such as electric vehicles (EV) and storage are also evaluated given their significant potential impact on future demand for energy.

Energy Sales Forecast

In general, the underlying economy driven sales forecast (“underlying forecast”) is derived first by using econometric methods and historical sales data, excluding impacts from energy efficiency measures and DG. This methodology captures the impact of economic growth rates, which are typically the most influential factor when forecasting long-term changes in sales and peak demand. Estimates of impacts from energy efficiency measures, DG installed through the Company’s tariffed programs and electric vehicles (referred to as “layers”) are then incorporated to adjust the underlying forecast to arrive at a preliminary sales forecast. This forecast then is used to drive the DER optimization routine (Figure D-46).

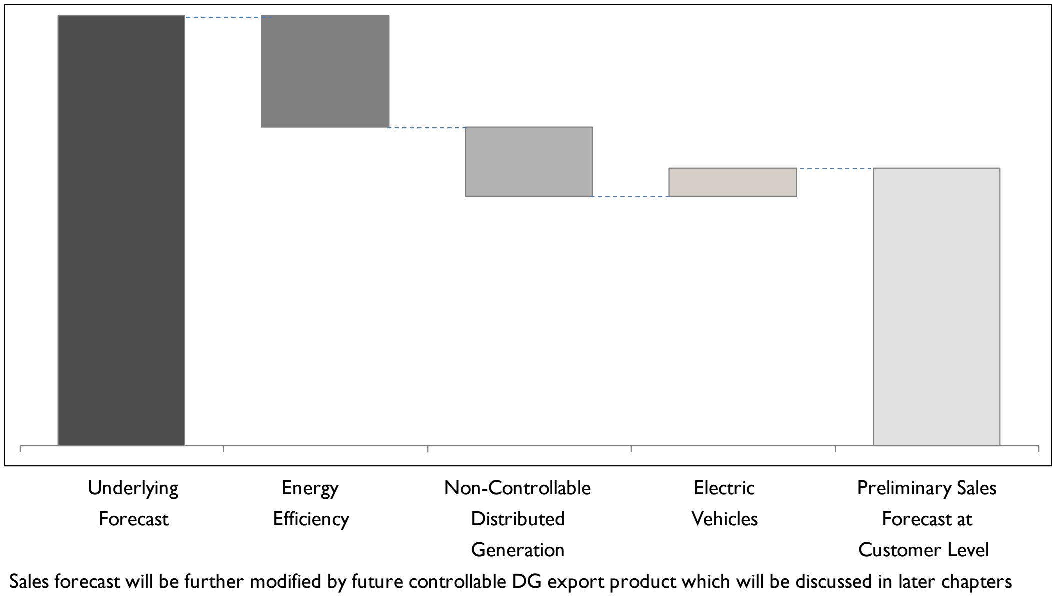

Figure D-46. Illustrative Waterfall Methodology for Developing Our Underlying Sales Forecast

The sales forecast to be served by each operating company through the study period expressed at the customer level is shown in Figure D-47 through Figure D-51. Data for the sales forecasts projections are detailed in Table A-27 through Table A-30 in Appendix A: Modeling Assumptions Data.

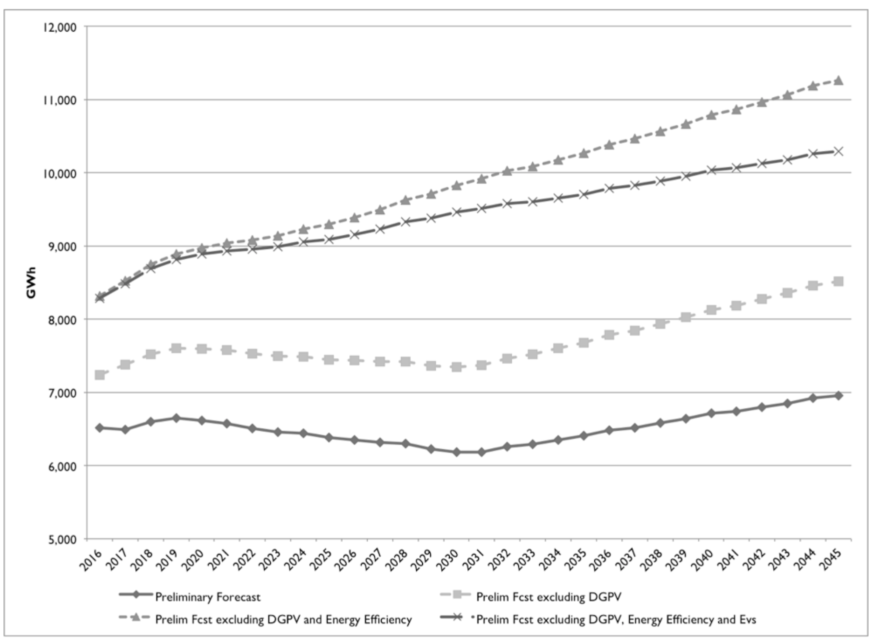

Figure D-47. O‘ahu Customer Level Sales Forecast

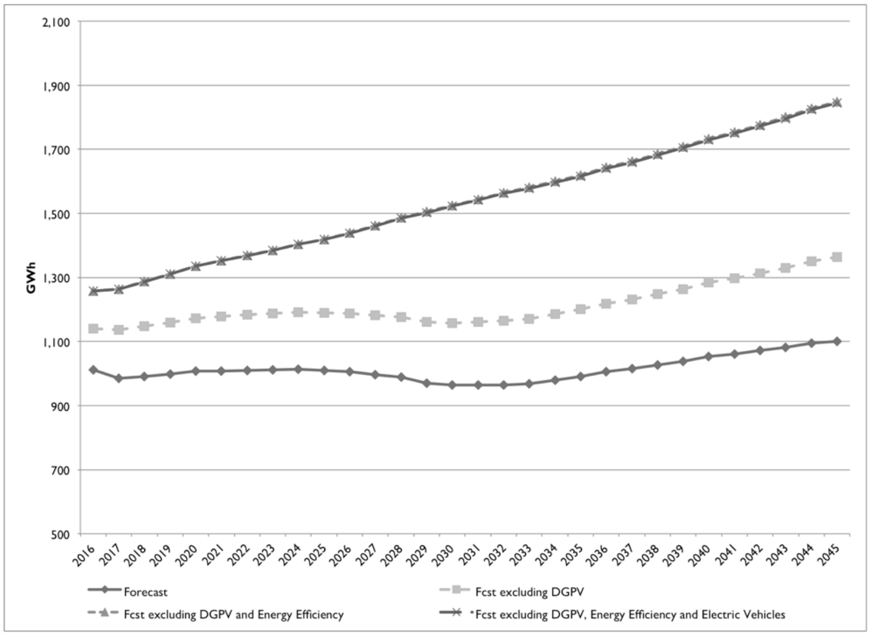

Figure D-48. Hawai'i Island Customer Level Sales Forecast

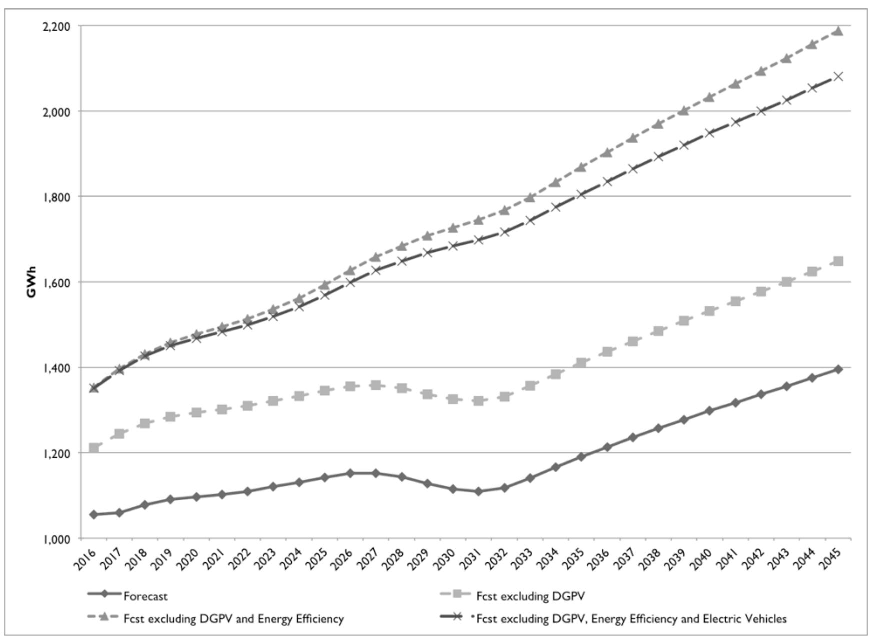

Figure D-49. Maui Island Customer Level Sales Forecast

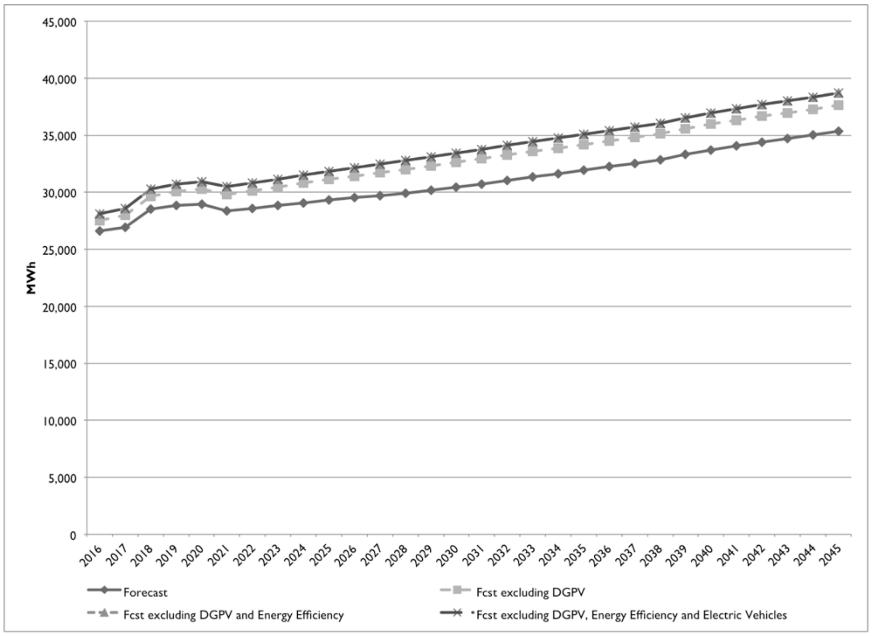

Figure D-50. Lana'i Customer Level Sales Forecast

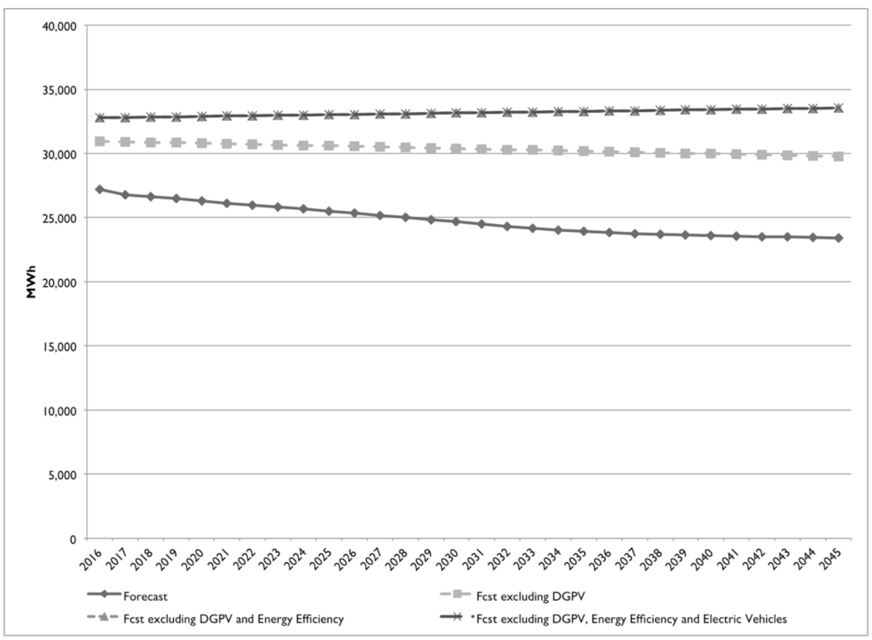

Figure D-51. Moloka'i Customer Level Sales Forecast

Underlying forecast. The underlying forecast incorporates projections for key drivers of the economy prepared by the University of Hawai'i Economic Research Organization (UHERO) in April 2015 such as job counts, personal income and resident population. Electricity price and weather variables are also included in the models.

Energy Efficiency. The preliminary projections for impacts associated with energy efficiency measures over the next five to ten years were assumed to be consistent with historical average annual impacts achieved by the Public Benefits Fund Administrator, Hawai‘i Energy. In addition to the impacts from Hawai‘i Energy's programs, changes to building and manufacturing codes and standards would be integrated into the marketplace over time contributing to market transformation. Collectively, these changes would support energy efficiency impacts growing at a faster pace in order to meet the longer term energy efficiency goal in 2030 (expressed in GWh). This pace is identified in the framework that governs the achievement of Energy Efficiency Portfolio Standards (EEPS) in the State of Hawai‘i as prescribed in Hawai‘i Revised Statutes § 269-96, and set by the Commission in Decision and Order No. 30089 in Docket No. 2010-0037. It was assumed the 30% sales reduction goal would continue beyond 2030. The preliminary projections did not consider participation in DR programs.

To determine the peak demand savings from energy efficiency, an average annual ratio between historical efficiency sales and peak impacts was applied to the projected annual energy impacts.

There is a significant uncertainty regarding the degree customers will engage in the adoption of energy efficiency measures, building practices and participation in DR programs. This will have a direct impact on projected sales and peak demand levels. If customer adoption is lower than projected, then demand for energy could exceed the forecasted levels and conversely, higher than projected would lower customer demand for energy. Over the 30-year planning period, participation may be higher or lower than the forecast depending on factors such as customer preferences, general economic conditions and availability of affordable technology. Although all future unknowns cannot be identified, the Company will work together with Hawai‘i Energy to develop alternative energy efficiency forecasts to better understand and address potential uncertainties.

Distributed Generation. The projections for impacts associated with distributed generation photovoltaic (DG-PV) systems installed under the Company's tariffed programs (legacy NEM, SIA, grid-supply to cap, self-supply and potential future grid-supply) were developed separately by program for residential and commercial customers and aggregated into an overall forecast for DG-PV systems. In the near term (through 2017) assumptions based on recent historical activity were made regarding the timing of system installations associated with the remaining applications in the legacy NEM queue. Near term SIA projections (through 2017) were based on known projects with anticipated installation dates in the two year window. Beyond 2017 the Company used a customer adoption model developed by Boston Consulting Group which forecasted future quantities of grid-supply up to the cap, self-supply, SIA and potential future grid-supply DG-PV systems. The model examines the relationship between economics and DG-PV adoption based on payback time, net present value (NPV) and internal rate of return (IRR) from the customer's perspective.

Figure D-52 through Figure D-54 depicts the preliminary DG-PV forecasts for O'ahu, Hawai'i Island, and Maui.

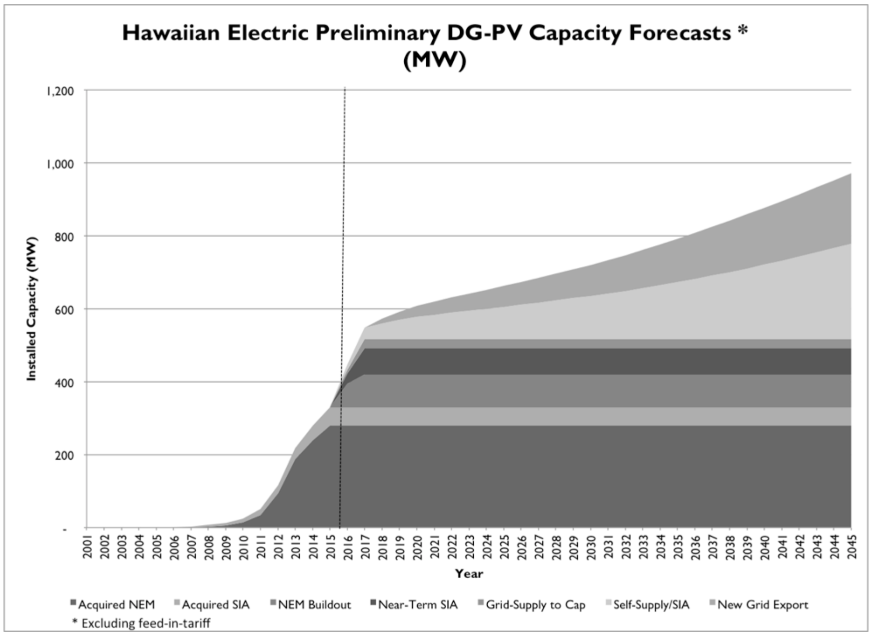

Figure D-52. O'ahu Preliminary DG-PV Capacity Forecasts

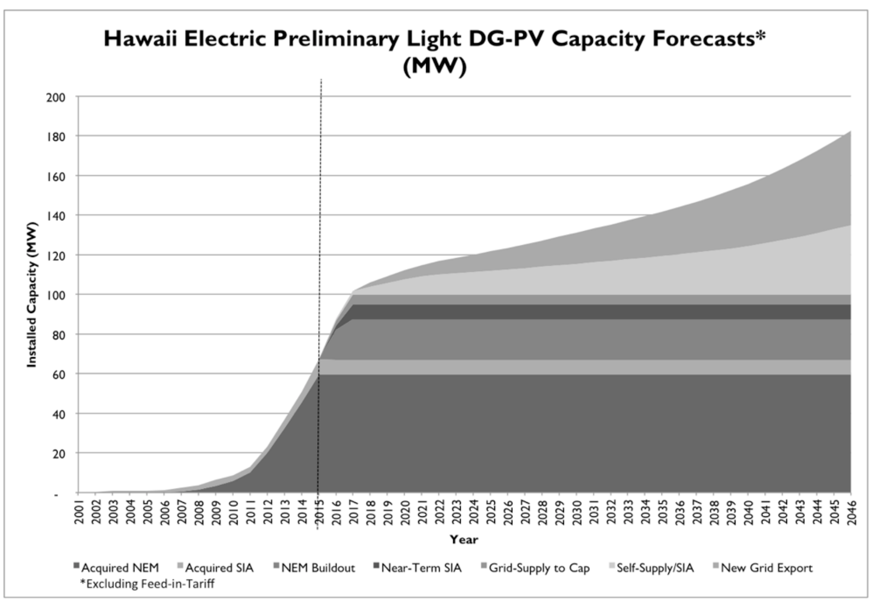

Figure D-53. Hawai'i Island Preliminary DG-PV Capacity Forecasts

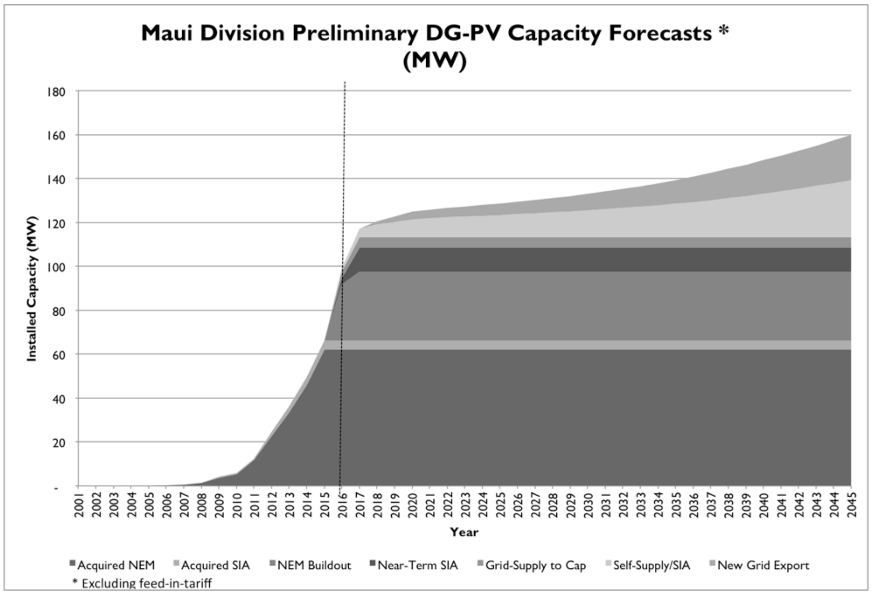

Figure D-54. Maui Island Preliminary DG-PV Capacity Forecasts

The customer adoption model was also used to forecast future DG-PV combined with the possibility of distributed energy storage systems.

Electric Vehicles. The development of the electric vehicles forecast was based on estimating the number of electric vehicles purchased per year using a historical average annual growth rate then multiplying by an estimate of the annual energy used per vehicle. The annual energy used per vehicle was based on the average miles driven per year as stated in the Hawai'i Data Book multiplied by the energy required per mile averaged over a 2015 Nissan Leaf, Chevy Volt, Chevy Spark and Tesla Model S.

Peak Demand Forecast

The peak demand forecast was derived using Itron's proprietary modeling software, MetrixLT. The software utilizes load profiles by rate schedule from class load studies conducted by the Company and the underlying sales forecast derived by rate schedule. The rate schedule load profiles adjusted for forecasted sales are aggregated to produce system profiles. The Company employed the highest system demands to calculate the underlying annual system. After determining the underlying peak forecast, the Company made adjustments that were outside of the underlying forecasts, for example impacts from energy efficiency measures. No adjustments were made to the preliminary underlying system peak forecast for DG-PV or electric vehicles as forecasted system peaks are expected to occur during the evening.

The underlying peak forecast for Lana'i and Moloka'i Divisions were derived by employing a sales load factor method which compares the annual sales in MWh against the peak load in MW multiplied by the number of hours during the year. For this preliminary forecast it was assumed the distributed storage systems and the effects of DR programs are not yet incorporated.

The preliminary peak demands of each operating company forecasted through the study period expressed at the net generation level are in Figure D-55 through Figure D-59. Data for the sales forecasts projections are detailed in Table A-32 through Table A-35.

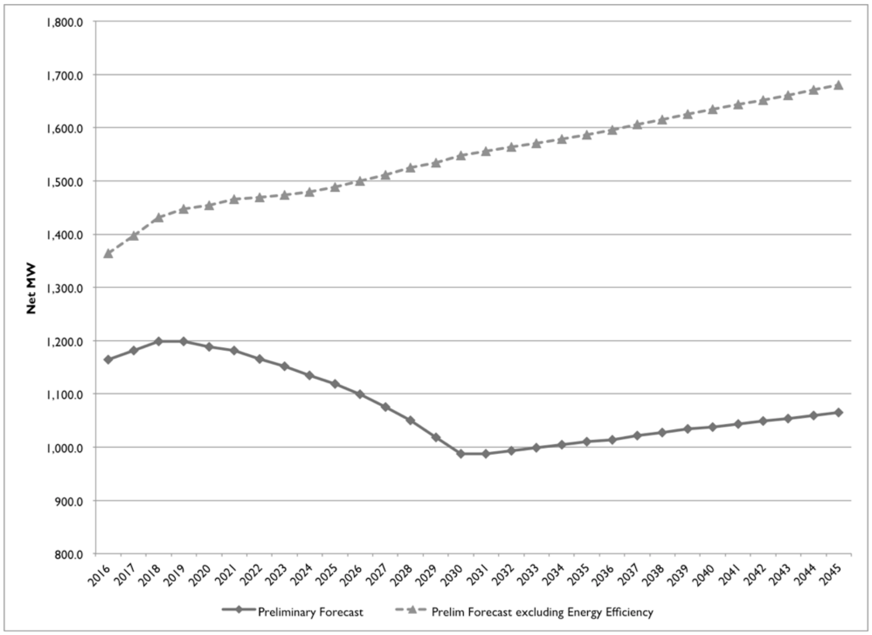

Figure D-55. O‘ahu Generation Level Peak Demand

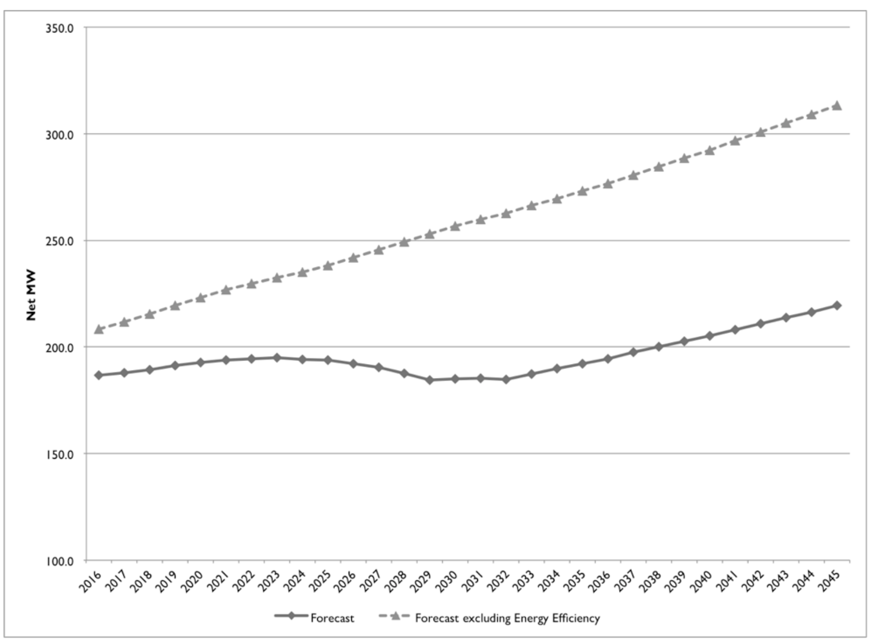

Figure D-56. Hawai‘i Island Generation Level Peak Demand

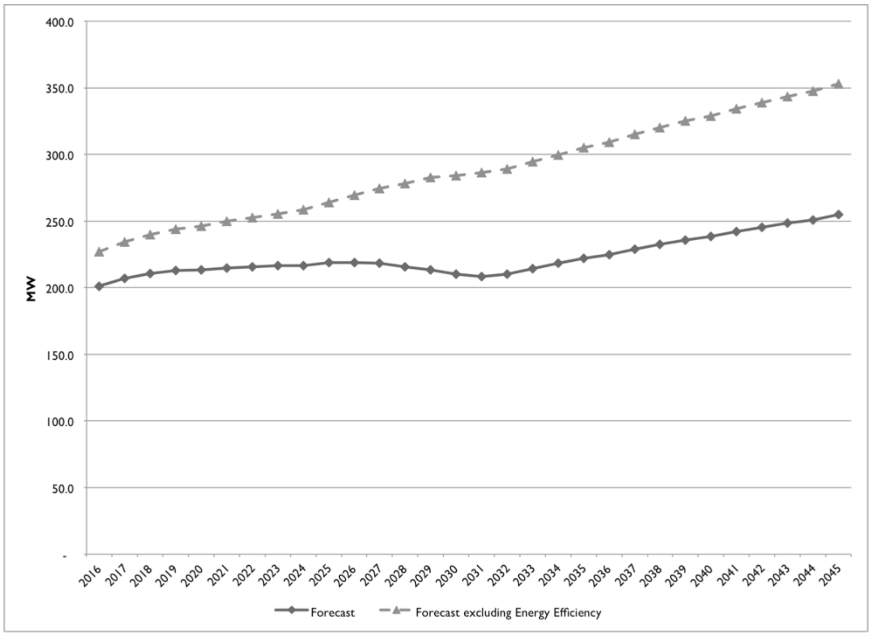

Figure D-57. Maui Island Generation Level Peak Demand

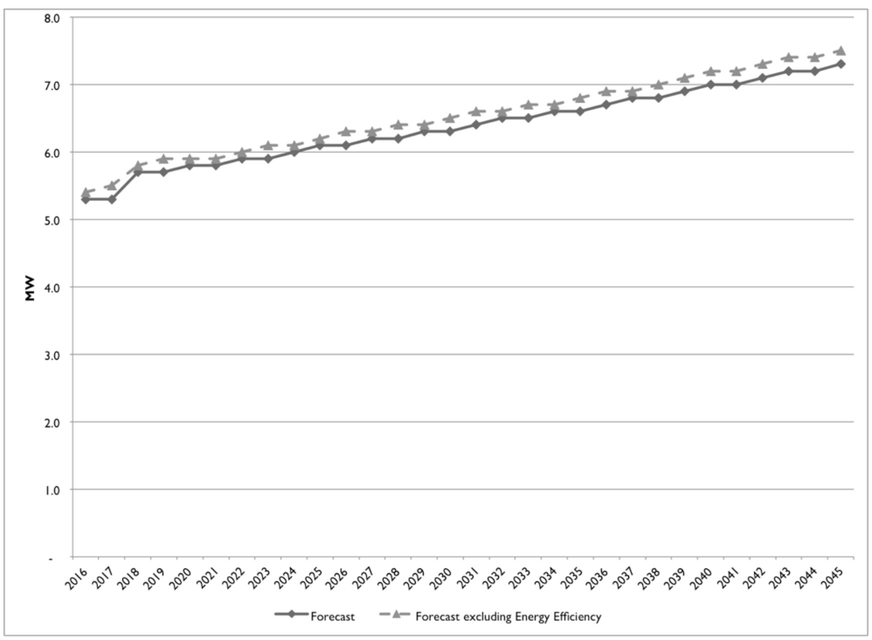

Figure D-58. Lana'i Generation Level Peak Demand

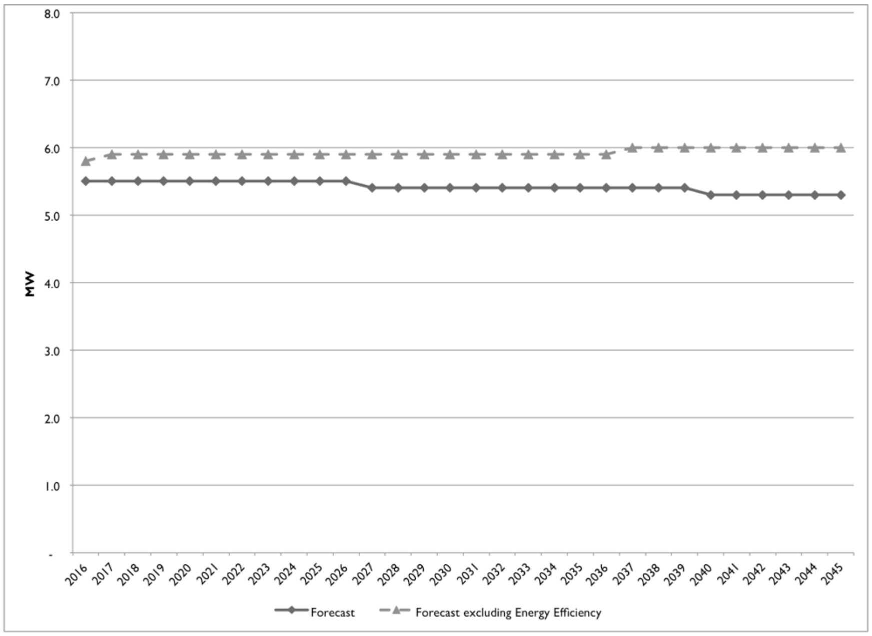

Figure D-59. Moloka'i Generation Level Peak Demand

Comparison to the August 2014 PSIP Forecast

The preliminary forecasts used in this filing are generally lower than the forecast used in the August 2014 PSIP filing for Hawaiian Electric and Hawai'i Electric Light for most of the PSIP planning range (Figure D-60 and Figure D-61). The primary factors contributing to the lower sales forecast in this filing are: 1) slower economic growth projection used to derive the underlying sales forecast and 2) the higher preliminary DG-PV potential. Although the national and local economy has been recovering since the great recession ended, UHERO lowered their economic outlook forecast to reflect the recovery taking longer and being less resilient than previously expected.

The preliminary forecast for Maui Electric used in this filing is similar to, but slightly lower than the forecast used in the August 2014 PSIP filing for the first several years of the PSIP planning range, then generally higher in the longer term (Figure D-62 through Figure D-64). While the twin effects of a weaker economic outlook and higher preliminary DG-PV potential affects underlying sales for Maui; this is partially mitigated by lower electricity prices in the near-term driving consumption and offsetting downward sales pressure.

A more optimistic real personal income per capita outlook for Maui specifically in 2025 and beyond, contributes to a higher underlying sales forecast in the long-term.

The preliminary forecast for Lana'i Division used in this filing is higher than the previous forecast used in the PSIP filing as newer information associated with the land owner's plans were incorporated (Figure D-63). The near term forecast reflects anticipated changes to the resort operations, and the long term impacts includes assumptions around an increase in the number of people on the island related to the expansion plans.

The preliminary forecast for Moloka'i Division used in this filing is lower than the forecast used in the PSIP filing (Figure D-64). The primary factor driving the lower sales forecast is impact associated with the higher preliminary DG-PV potential.

The preliminary DG-PV forecasts for all companies reflect continued customer interest in the near term including a faster pace of releasing the legacy NEM queue, the changes made to the Federal Investment Tax Credit beyond 2016, and interest in the new programs such as grid-supply and self-supply. The lower sales were partially offset by the effects of lower electricity prices driven by lower fuel oil prices and new construction projects identified between forecasts. The energy efficiency forecasts were also refreshed with additional historical years of performance by Hawai'i Energy and the assumption of achieving a 30% sales reduction in 2030 were applied to different sales forecast resulting in achieving different impact levels. The impacts from the energy efficiency refresh had varying results for each company. Hawaiian Electric's energy impacts were lower in the near term and higher in the long term when compared against the PSIP forecast. Hawai'i Electric Light's were higher in the near term and lower in the long term and Maui Division was lower for the entire planning range.

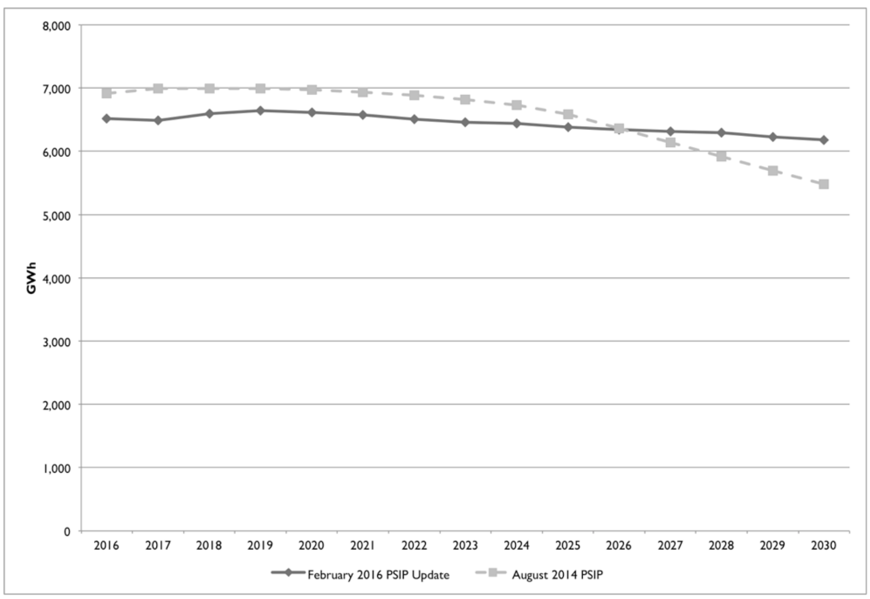

Figure D-60. O'ahu Sales Forecast Comparison

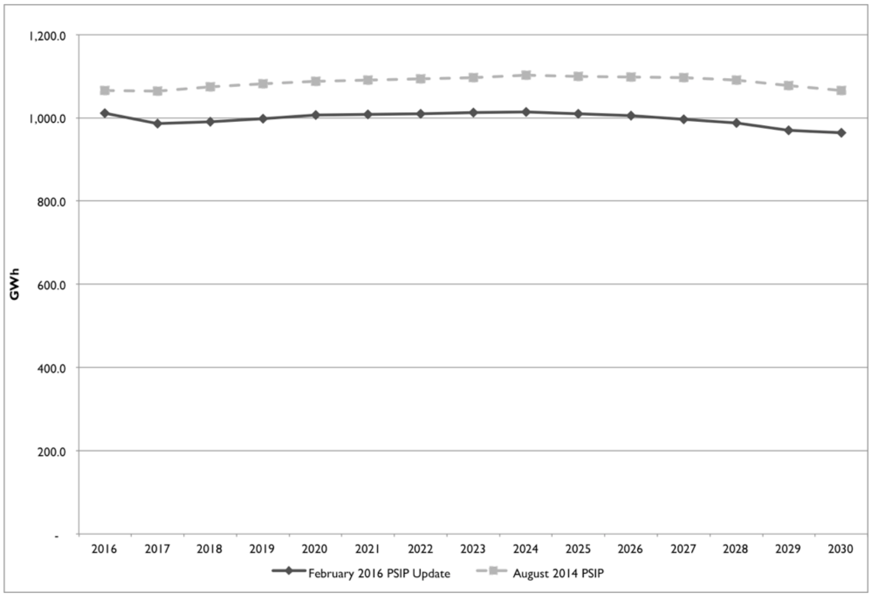

Figure D-61. Hawai'i Island Sales Forecast Comparison

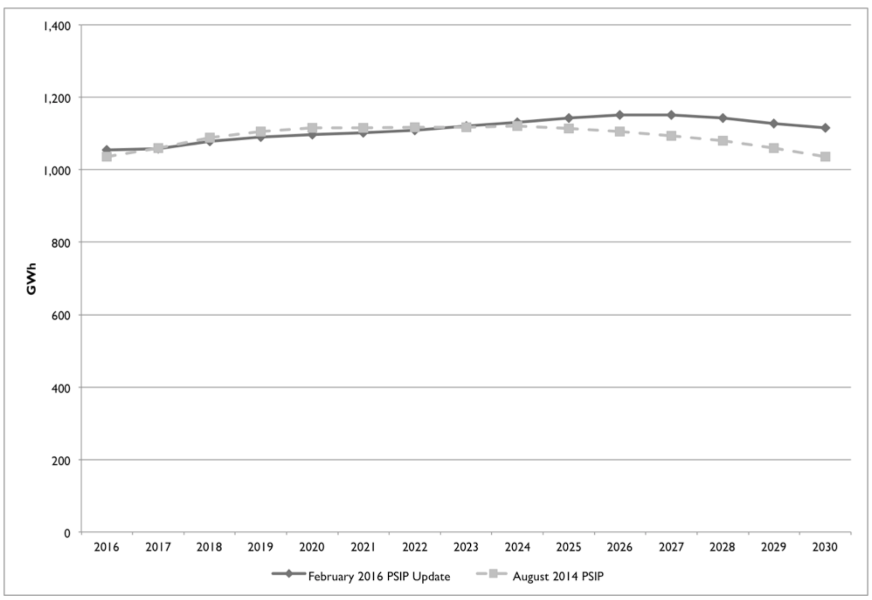

Figure D-62. Maui Island Sales Forecast Comparison

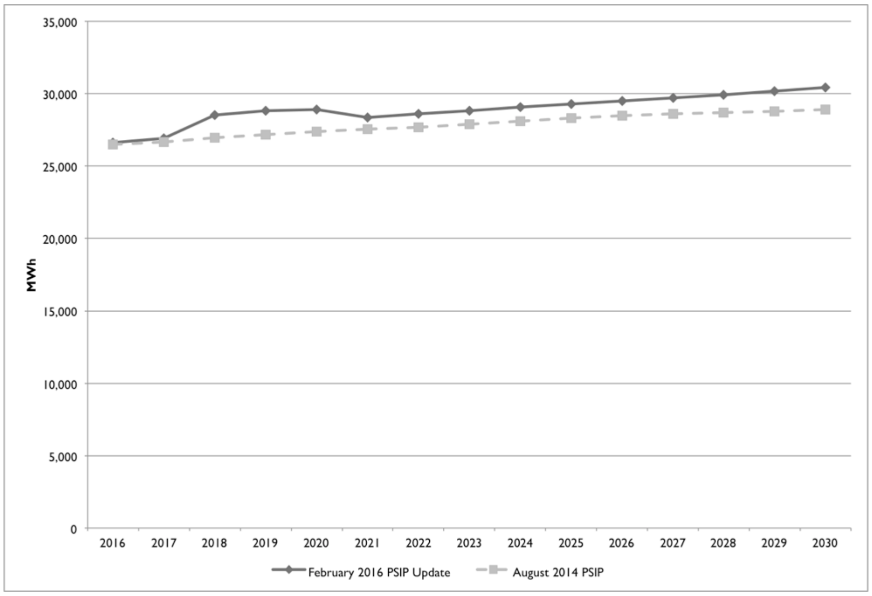

Figure D-63. Lana'i Sales Forecast Comparison

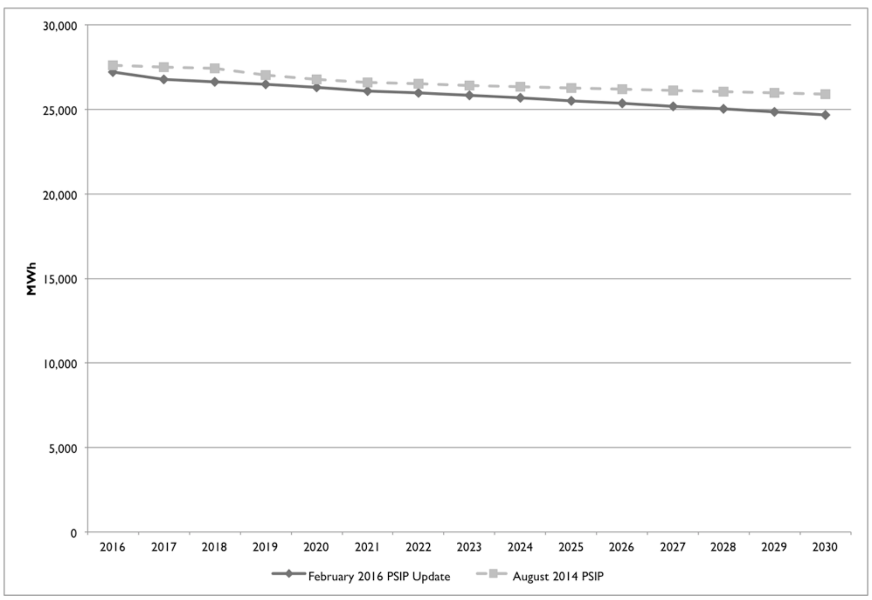

Figure D-64. Moloka'i Sales Forecast Comparison

See Table A-37 through Table A-41 in Appendix A for the detailed sales comparison between the preliminary sales forecast and PSIP sales forecast.

Note that the peak forecasts were developed using the method described in the prior page and the differences between the current preliminary forecasts and the PSIP forecast are a result of the differences in the sales forecasts.

UHERO's Economic Forecasts

UHERO's forecasts for non-farm jobs, personal income, and visitor arrivals were used in developing the sales forecasts. Figure D-65 through Figure D-67 compare the economic forecasts developed by UHERO in 2015 against the forecast developed in 2014, illustrating the less optimistic outlook between the two forecasts. See also Table A-42 through Table A-44 in Appendix A for a comparison between UHERO's April 2014 and April 2015 economic forecasts.

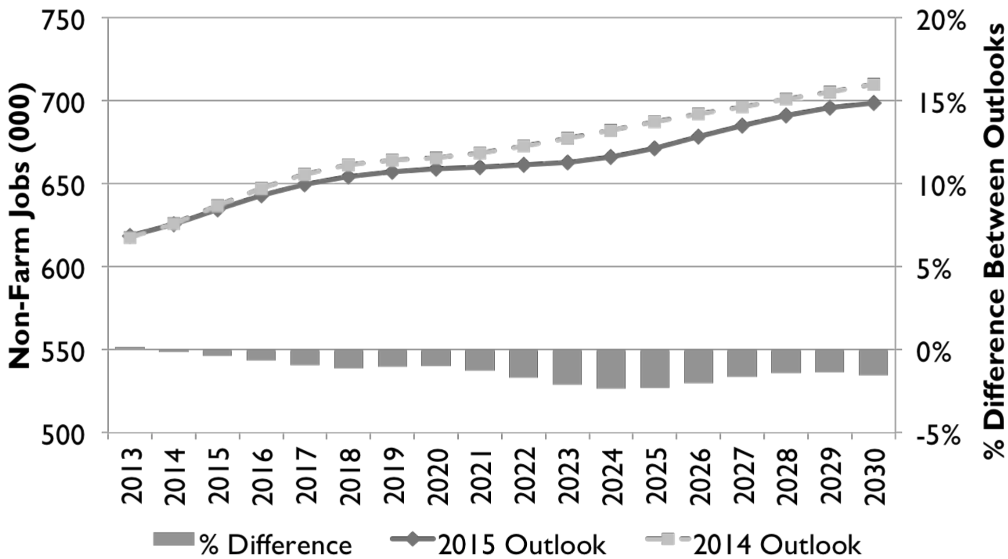

Figure D-65. Hawai'i Non-Farm Job Count Forecast Comparison

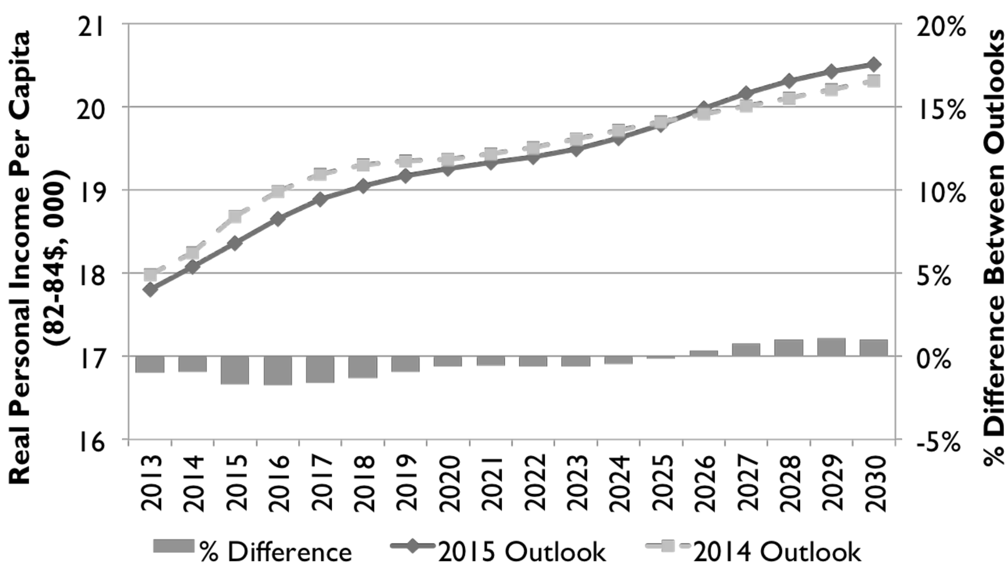

Figure D-66. Hawai'i Real Personal Income per Capita Forecast Comparison

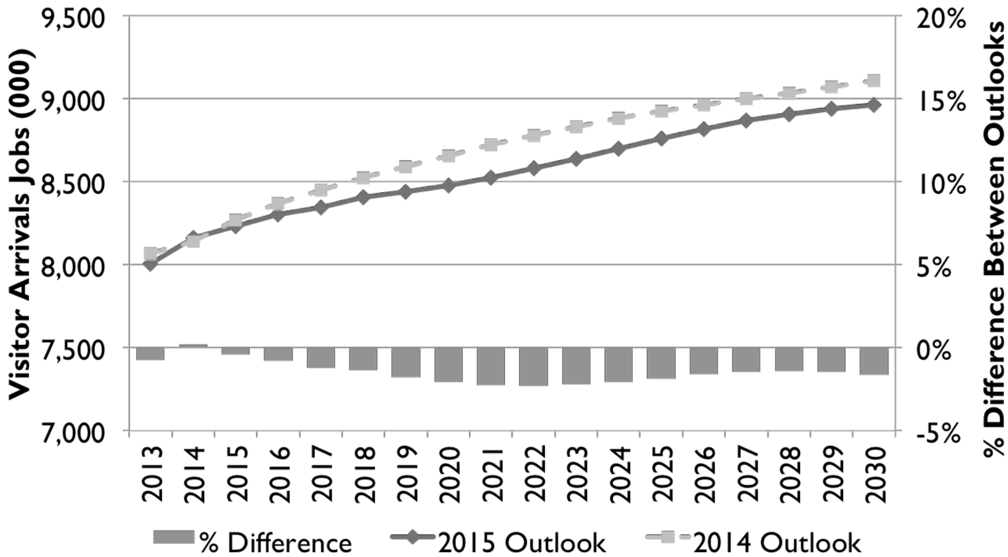

Figure D-67. Hawai'i Visitor Arrival Forecast Comparison

Load Profiles

Available generating resources must be able to meet a demand profile over a period of time that doesn't include customer-sited distributed generation. Our analysis used a demand profile in two ways:

- An annual hourly load profile (8,760 data points: 365 days at 24 hours a day).
- A sub-hourly load profile data, which model intra-hour issues associated with ramping of generating resources and energy storage in response to variable renewable generation.

Because of the proliferation of customer-sited distributed generation, the net load profile has changed dramatically over the past few years. Our analysis assumed a system gross load profile. The model includes the profile of customer-sited distributed generation, which results in the net load to be served.

Sub-Hourly Profile

Black & Veatch has developed sub-hourly profiles for variable generation that includes rooftop solar panels, and utility-scale solar and wind. These profiles form the backbone for evaluating the impacts of variable generation and the fleet's ability to meet demand.

Black & Veatch's model is based on historical changes in minute-to-minute generation by asset type and island. Using historical data, the model creates a probability distribution function based on time of day and current generation levels. The probability, then, is a distribution of all the possible changes in demand for an asset type. Combining this probability with random number generation results in the change in output for the next time step for that asset.

The model "fills in" the sub-hourly generation of each asset in between the hourly generation profiles provided by the Hawaiian Electric planning group. Black & Veatch's model ensures that energy production over each day with the sub-hourly profiles matches the production from the hourly model. This daily energy matching aligns total production with models that employ only hourly data.

The difference between the modeling data for sub-hourly versus hourly is dramatic. Figure D-68 depicts an example day of an hourly profile on the Hawaiian Electric grid and the output profile from the Black & Veatch model.

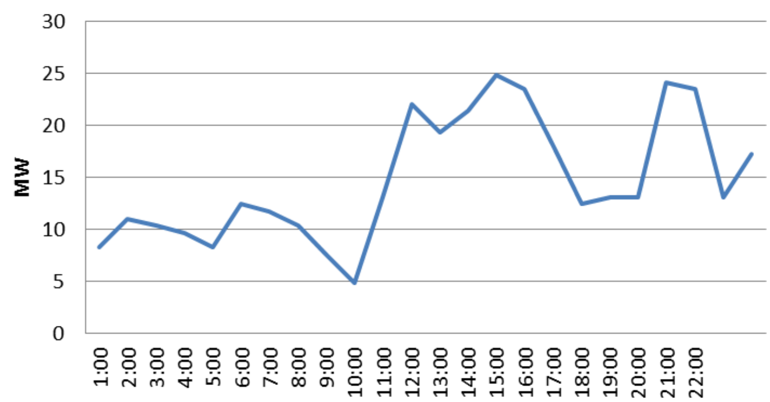

Figure D-68. Wind Unit Day Hourly Profile Example

Figure D-69 depicts an example day of an hourly profile on the Hawaiian Electric grid and the output profile from the Black & Veatch model.

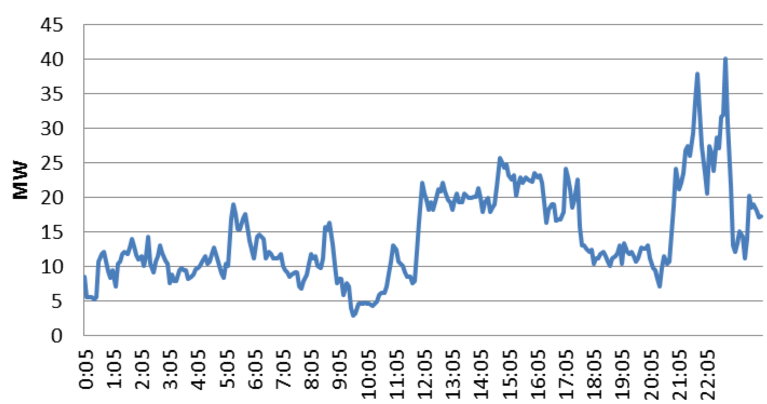

Figure D-69. Wind Unit Day Sub-Hourly Profile Example

Fuel Price Forecasts and Availability

LNG Price Forecasts

The delivered price of LNG to Hawai'i can be disaggregated into four parts: gas as a commodity, pipeline transport, liquefaction, and transportation and logistics.

Gas Commodity

Two different commodity pricing curves were used for the LNG price forecasts:

1. U.S. Energy Information Administration 2015 reference Henry Hub natural gas spot price forecast in nominal dollars.
2. CME Henry Hub Gas futures curve escalated at 4% from 2030 to 2040 in nominal dollars.

Henry Hub, a Louisiana natural gas distribution hub and pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX), is currently at a 15-year price low. The price is expected to increase gradually over the next decade as the shale gas market rebalances. The LNG price forecast is based on natural gas sourced from British Columbia. Historically and based on the future's market pricing, gas sourced from Alberta (AECO market) and British Columbia (Station 2 gathering point) has traded at a discount to the United States Henry Hub pricing.

For Hawaiian Electric's LNG pricing curves, a negative 26.5% basis was applied to create a Station 2 equivalent Henry Hub price. For example, a $2.00/MMBtu Henry Hub price would equate to a $1.47/MMBtu Station 2 price. A 4.5% adder was applied to the derived Station 2 price to account for shrinkage on the pipelines from the Station 2 gathering point to the liquefaction plant. (Refer to Appendix A for specific pricing.)

Pipeline Transport

We expect that natural gas for Hawai'i will be procured under a daily or monthly index, gathered at Station 2 and transported on the Spectra Energy Westcoast Transmission T-South pipeline. T-South is a looped (multiple pipeline) system that moves gas from Station 2 to the Huntingdon/Sumas (Sumas) trading pool. T-South firm capacity can be procured at a rolled-in tariff rate, meaning that if capital improvements are required to increase pipeline capacity, expansion costs are borne by all users on the pipeline. Charges to use the pipeline will be at a fixed tariff CAD/GJ rate, converted to $/MMBtu. As a mature depreciating pipeline system, the general trend is towards stable long-term rates. The current rate is approximately $0.32/MMBtu.

From the Sumas hub, gas will be distributed on the Fortis regulated Coastal Transmission System (CTS) to the existing FortisBC Energy Inc. (FEI) LNG facility on Tilsbury Island in Delta, British Columbia, Canada on the Fraser River. The CTS pipeline rate is regulated under the Rate Schedule 50 (RS50) tariff in units of CAD/GJ and converted to \$/MMBtu for the Hawaiian Electric contract. The FEI CTS system is designed to meet high winter peaking demand and is therefore under-utilized for a majority of the year. Therefore, if more flat non-peaking load is added, by Hawaiian Electric or other industrial demand, the general trend would be for rates to reduce. This is reflected in the RS50 rate floor which decreases as demand increases. The current tariff rate under RS50 is approximately \$0.42/MMBtu.

Renewable Portfolio Model Assumptions: O‘ahu-Only Case

O‘ahu Island Constraints

A renewable portfolio was modeled that includes DER, utility scale renewables, thermal generation operating on biofuel and a load shifting battery energy storage system (BESS) in order to ensure the maximum use of the variable renewable generation on O‘ahu. This case is desirable to evaluate because it limits the amount of utility scale renewables based on both the resource potential and the ability to integrate them on O‘ahu.

In order 33320, the Commission expressed concern that the constraints on resources by island in the 2014 PSIPs were "unsubstantiated."[33] We acknowledge that an accurate and realistic estimate of the incremental resource potential, particularly on O‘ahu, is very important in light of Hawaii Act 97 providing for the 100% RPS. To the extent that there are significant constraints on O‘ahu, the strategic need for off-island options (e.g. off-shore wind, inter-island cables, etc.) becomes greater.

In order to address the Commission's concern in this area, the Companies commissioned NREL to perform an analysis of the resource potential by island. However, during this initial analysis phase, the NREL results were not available. Accordingly, the Companies and the NextEra renewable development team reviewed two publically available studies that evaluated both the potential and the ability to integrate renewables on O‘ahu:

- Hawai‘i Solar Integration Study – Final Technical Report for O‘ahu – December 7, 2012.
- Hawaii Renewable Portfolio Standards Study prepared for Hawaii Natural Energy Institute by GE Energy Consulting, May 2015.

In the Companies' analysis, after the potential amounts of wind and solar on O‘ahu was developed, that information was compared against the available useable land on O‘ahu for utility scale solar PV.

[33] Order No. 33320, Concern 2.c. at 84.

The criteria for determining usable land for solar PV included the following:

a. Slope less than 6%.

b. Within one mile of a transmission interconnect.

c. Above the 40 feet elevation plain, ensuring placement out of the tsunami inundation zone.

d. Land categories B, C, D and E are available for solar construction, with B and C available with special use permits, as long as they do not occupy more than 10% of the acreage of the parcel or 20 acres, whichever is less.

e. Five acres of land per MW.

The additional solar PV of 400 MW uses 10% of the total line meeting this criteria, while the total solar PV of 715 MW uses approximately total solar PV modeled in this PSIP of 715 MW utilizes approximately 18% of this available land (Table D-82).

	Less than 6% Slope, within 1 mile of T&D				
MW	*% of b*	*% of c*	*% of d*	*% of e*	*% of Total*
50	2%	16%	32%	5%	1%
100	4%	31%	64%	9%	3%
150	6%	47%	96%	14%	4%
200	8%	63%	–	18%	5%
250	10%	79%	–	23%	6%
300	13%	94%	–	28%	8%
350	15%	–	–	32%	9%
400	17%	–	–	37%	10%
450	19%	–	–	42%	11%
500	21%	–	–	46%	13%
550	23%	–	–	51%	14%
600	25%	–	–	55%	15%
650	27%	–	–	60%	16%
700	29%	–	–	65%	18%
750	31%	–	–	69%	19%

Table D-82. Usable Land Siting for Utility-Scale PV on O‘ahu

Utilizing the results of the available third party reports, and the methodology described above, we determined that it was possible to install additional solar PV of 400 MW above the amounts in the 2014 PSIP (using 10% of the total land meeting this criteria), plus the 2014 PSIP amounts of solar PV for a total of 715 MW. As shown in Table D-79, 715 MW would use approximately 18% of the land available. We determined that 100 MW of additional wind resource is available on O'ahu.

Subsequent to our analysis above, and as we were preparing this document, the results of the NREL analysis were received.

Table D-83 shows the preliminary results of the NREL analysis regarding the potential for new wind and solar resource potential by island. These results indicate that while the neighbor islands have substantial "developable" resource potential, O'ahu is reaching its limits with respect to additional wind resources. With respect to utility-scale solar PV potential on O'ahu, there is still adequate resource potential, if it is possible to develop solar PV on lands with slopes greater than 3%. If a slope of more than 3% is a limitation on the development of utility-scale solar PV on O'ahu, then the remaining solar PV potential on O'ahu is zero. As noted, these results from NREL were received shortly before this filing was made and we have not had time to discuss the results with NREL. According, we reiterate that these results are preliminary.

Preliminary Results of NREL's Island Resource Potential Study				
Resource	*Exclusion Criteria*	*O'ahu*	*Hawai'i*	*Maui*
Utility Scale PV	Excludes capacity factor potential less than 20%, Excludes all areas with slope greater than 5%	621 MW	45,951 MW	1,666 MW
Utility Scale PV	Excludes capacity factor potential less than 20%, Excludes all areas with slope greater than 3%	0 MW	3,704 MW	0 MW
Utility-Scale Wind	Excludes all areas with wind speeds less than 6.5 meters / second at 80 meters high	174 MW	3,276 MW	698 MW

Table D-83. Preliminary Results of NREL's Island Resource Potential Study

O'ahu Renewable Portfolio

One method to achieve 100% RPS with an on-island solution is to burn renewable fuels in existing or modernized generation facilities. Other off-island methods including inter-island grid ties and integration of offshore wind generation will be considered in the Updated PSIPs submittal.

Cost impacts to be considered in the development of this on-island solution were:

- Cost of the utility scale renewables and load shifting bulk energy storage systems (BESS)
- Fuel cost for biofuel use in the thermal generation assets

Based on our internal analysis of resource potential (i.e. prior to receipt of the NREL study results), the portfolio of renewable resources in the initial O'ahu analyses assumed total variable renewable resources for the study period through 2045 that include

- 273 MW of utility-scale wind; and

- 615 MW of utility-scale solar PV.

For the Updated PSIPs, several alternative portfolios will be analyzed to ensure the most cost effective one is selected. The portfolio analyzed in this Interim PSIP submittal will be analyzed further to ensure resource constraints are properly considered, there is the optimum amount and types of energy storage resources to support the renewable portfolio and biofuel use is optimized. Off-island portfolio options will also be analyzed to determine the benefits of bringing renewable generation to O‘ahu from an offshore source through an inter-island grid tie. This grid-tie will enable more renewable generation to be brought into O‘ahu to support meeting generation needs, smoothing the variation inherent to intermittent renewable generation and improving system security on all of the islands that are connected.

Online Reserve Requirement for Renewable Fleet Support (O‘ahu)

Given the variable nature of renewables, there will be significant volatility in the amount of renewable generation contribution on a daily basis. The existing fleet is not currently equipped to respond quickly enough for the anticipated increase in the amount of variable renewable energy supply.

One method of supplementing the existing dispatchable fleet to address the volatility from the additional variable renewable energy sources would be to add large, utility-scale batteries to the system. The amount of support needed from the batteries, however, is significant and does not appear to be an optimal use of capital resources for these purposes. An alternative to adding a large and costly storage system would be to keep the existing thermal units on at minimum load as online reserve generation. While this option would reduce the amount of batteries that would be required, and thereby reduce the associated costs, any savings would be offset by the costs associated with running one or more units whose power would otherwise not be required to serve load. In that situation, keeping the thermal units on at minimum load would be akin to letting an automobile idle just to ensure its readiness at any time. In order to avoid the costs associated with maintaining online reserve generation, and simultaneously make room for the potential addition of more renewable resources, an alternative would be to replace the existing thermal units with a dispatchable fleet that can start and ramp up quickly.

The Companies performed an evaluation to compare the existing fleet to a modernized fleet and the respective abilities to respond to a large cloud cover event. Figure D-70 was developed based upon the results of a Wind Logics study that evaluated the projected 2045 renewable resources in order to understand the largest generation swings that could be expected.

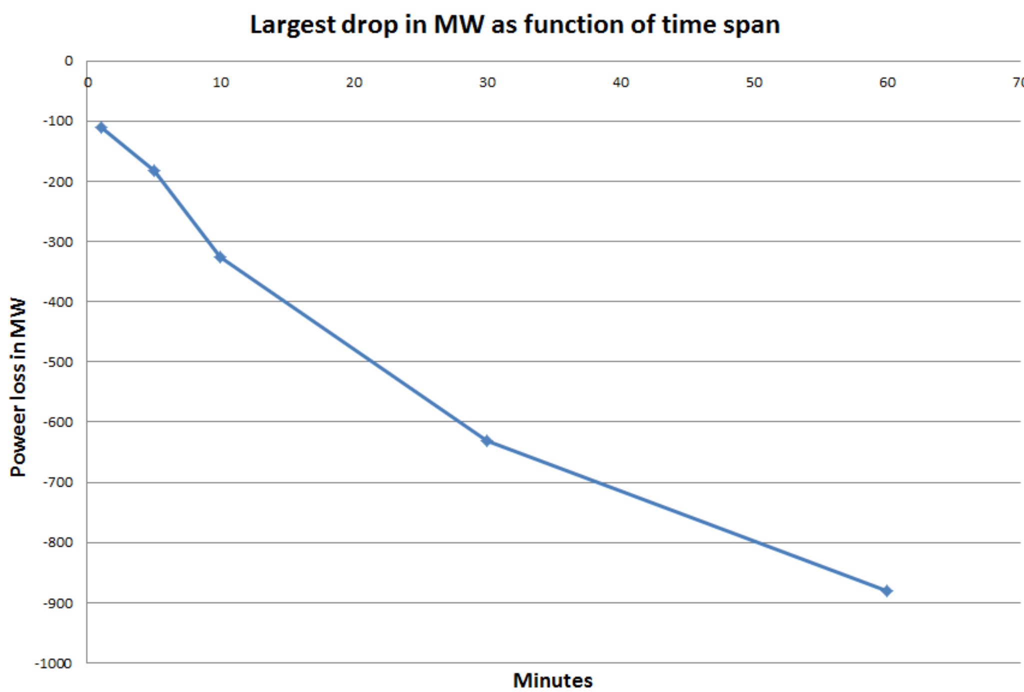

Figure D-70. Largest Drop in MW as a Function of Time Span

The graph above shows the largest expected drop over a one-year time period, in time increments. For example, the largest MW drop in a 30-minute time period. The results from this study were used to analyze the system response to a drop of 630 MW within a 30-minute time period. These events are best described as "large cloud cover events".

When analyzing the existing fleet, the Companies considered the units that were available to respond to the event. The size of the battery storage system (BESS) to address this type of event would need to be sized to handle the initial load response. However, as the BESS is called on to supply larger and larger amounts of generation for longer and longer time periods, the cost increases exponentially. A more cost effective solution would therefore be to replace the lost potential generation from a cloud cover event with resources that are fully dispatchable by the Companies.

Table D-84 summarizes the existing Hawaiian Electric fleet.

Unit	Type/Fuel	Capability		Year Commercial
		Gross MW	Net MW	
Kahe 1	Reheat Steam/LSFO	86	82.2	1963
Kahe 2	Reheat Steam/LSFO	86	82.2	1964
Kahe 3	Reheat Steam/LSFO	90	86.2	1970
Kahe 4	Reheat Steam/LSFO	89	85.3	1972
Kahe 5	Reheat Steam/LSFO	142	134.6	1974
Kahe 6	Reheat Steam/LSFO	142	133.8	1982
Waiau 7	Reheat Steam/LSFO	87	83.3	1966
Waiau 8	Reheat Steam/LSFO	90	86.2	1968
Total Baseload/Load Following Capability		812	773.8	Average Age
Waiau 3	Non-Reheat Steam/LSFO	49	47	1947
Waiau 4	Non-Reheat Steam/LSFO	49	46.5	1950
Waiau 5	Non-Reheat Steam/LSFO	57	54.5	1955
Waiau 6	Non-Reheat Steam/LSFO	56	53.7	1961
Total Cycling Capability		211	201.7	Average Age
Waiau 9	Simple Cycle CT	53	52.9	1973
Waiau 10	Simple Cycle CT	50	49.9	1973
CIP CT-1	Simple Cycle CT	113	112.2	2009
Total Peaking Capability		216		

Table D-84. O'ahu Fleet Specifications

After factoring in the starting time, ramping capability and minimum operating load of each unit, the Companies determined that all of the peaking units, the IPP unit at Kalaeloa, and the baseload units at Kahe 3, 4, 5, and 6 would be required to adequately respond to this cloud cover event. Since the Kahe units need between four and six hours to start up, those units would need to be on line in order to respond quickly enough to the event.

TIME (MINUTES)	K3	K4	K5	K6	W9	W10	CIP	KPLP	Schofield	Dod
0	5	5	25	45	0	0	0	65	0	0
15	35	35	55	105	17	17	0	65	50	127
30	57	57	91	142	47	44	113	102.5	50	127
45	65	65	103	142	47	44	113	140	50	127
60	73	73	116	142	47	44	113	177.5	50	127
75	81	81	130	142	47	44	113	208	50	127
90	90	89	142	142	47	44	113	208	50	127
105	90	89	142	142	47	44	113	208	50	127

Total Generation Changes	With K7
Initial Time	*Initial Time*
0	0.0
15	361.0
30	685.5
45	751.0
60	817.5
75	878.0
90	907.0

Table D-85. Response Time of Existing Fleet to 630 MW Renewable Resource Loss Event

The Companies performed a similar review for a modernized fleet, which would replace Kahe units 1, 2 and 3 with the 3 x 1 combined cycle unit (Kahe Combined Cycle). According to our studies, the Kahe Combined Cycle unit, with its fast start up time and quick ramping capability, would be able respond to this large cloud cover event without having to be online like the slower base loaded units. Table D-86 reflects the start time, in minutes, for the various units.

TIME (MINUTES)			K7				W9	W10	CIP	KPLP	Schofield	Dod
0			0				0	0	0	65	0	0
15			215				17	17	0	65	50	127
30			345				47	44	113	102.5	50	127
45			349				47	44	113	140	50	127
60			383				47	44	113	177.5	50	127
75			383				47	44	113	208	50	127
90			383				47	44	113	208	50	127
105			383				47	44	113	208	50	127

Total Generation Changes	With K7
Initial Time	*Initial Time*
0	65.0
15	426.0
30	763.5
45	805.0
60	876.5
75	907.0
90	907.0

Table D-86. Response Time of Modernized Fleet to 630 MW Renewable Resource Loss Event

The above analysis demonstrates that at least four of the currently utilized base load steam units would be required to be online at their minimum output plus a downward regulating margin in order to adequately respond to large cloud cover events. As the renewable fleet grows in size, however, the need for the steam units would decrease, and the economic dispatch model would lower their capacity factors to zero. If they were not needed to respond to these large cloud cover events, they could be left in cold standby using zero fuel, or possibly even be retired. As demonstrated above, these base load units must be used as online reserve because of their slow startup times if they are going to be relied upon to respond to large system events. The cost for keeping the online reserve equates to the cost of fuel to keep these units on at minimum load during all daylight hours that the large cloud cover event could occur. The calculated cost of this extra fuel is demonstrated in Figure D-71.

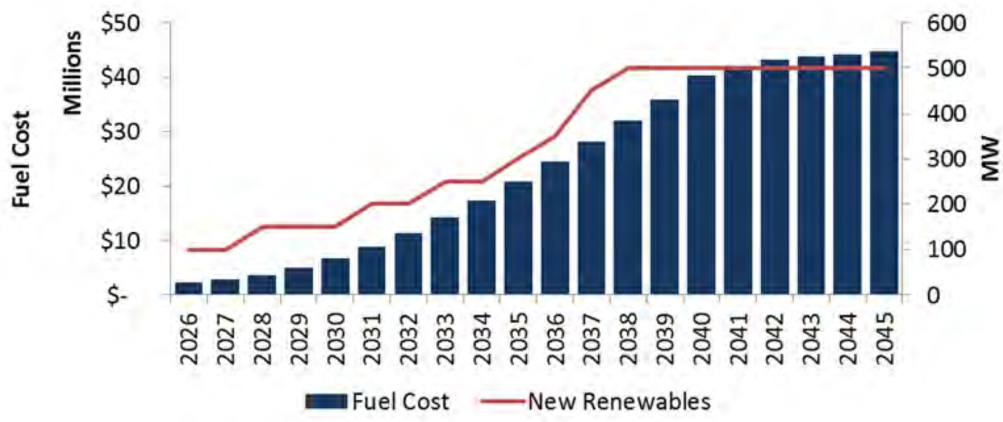

Figure D-71. Extra Fuel Cost

The modernization of the fleet will enhance its ability to support the renewable fleet of the future by enabling the renewables to support the demand and leaving the dispatchable units offline until they are needed.

Distributed Energy Resources Cost Assumptions

DER resource capital cost assumptions were developed utilizing the same methodology described above for utility-scale resources, and utilizing many of the same sources. For the purposes of the PSIP DER analysis, we concentrated on rooftop solar PV, residential lithium-ion BESS and behind-the-meter commercial customer class BESS. In particular, for each of these technologies, we utilized IHS Energy's projections of distributed solar and energy storage costs, applied Hawai'i locational adjustments using RSMeans data, and added 4% for Hawai'i General Excise Taxes. For solar PV in particular, we validated this data against anecdotal data points obtained through a conversation with a solar PV integrator active in the Hawai'i market.[34]

[34] Company consultant HDBaker & Company's private conversation with a private company that provides turnkey solar PV solutions in Hawai'i.

The available data for residential systems from IHS included only the storage medium, and not the balance of plant components, under the assumption that the distributed storage would be installed in conjunction with a solar PV system that incorporates the inverter and other balance of plant items. We believe that there are opportunities for stand-alone distributed energy storage. Accordingly, we added balance of plant cost estimates to develop stand-alone storage costs.

The projections of capital costs for distributed solar PV and customer-owned BESS energy storage systems are included in the tables in Appendix A.

Inter-Island Cable Assumptions

Our 2016 PSIP analysis will consider the feasibility of inter-island cables. Because of the distances involved between the islands, interconnections between the islands will be accomplished by using High Voltage Direct Current (HVDC) technology, including converter stations on either end of a submarine cable. Submarine HVDC systems have been successfully deployed around the world, and the market for HVDC systems is expected to dramatically increase in the future.[35]

There are relatively few vendors of HVDC technology, however the vendors that are active in this market are global players, with large balance sheets and the ability to support this technology. HVDC systems exhibit a high level of reliability and are highly controllable, providing flexibility in terms of providing grid services.

Capital cost assumptions for a 200 MW and 400 MW cable system between Maui and O'ahu were developed by NextEra in consultation with HVDC vendors. HVDC projects are typically developed with the vendor providing turnkey engineering-procurement-construction (EPC) serves with guaranteed prices (subject to sliding cost categories related to commodity prices), guaranteed schedules, and guaranteed performance.

[35] http://www.marketsandmarkets.com/Market-Reports/hvdc-grid-market-1225.html.

EXISTING UNIT REQUIREMENTS AND DESCRIPTIONS

Hawaiian Electric Existing Generation

Hawaiian Electric recognizes certain challenges with integrating high levels of variable renewable energy into the current generation fleet. The existing steam generating fleet has certain disadvantages compared to a modern generation fleet.

- Slower ramp rates
- Longer start up times
- Higher maintenance cost associated with cycling/turndown
- Less efficiency

The Hawaiian Electric owned existing generation has served our customers well over many decades in a traditional electrical system. As the electric system evolves and includes higher penetrations of variable energy the existing fleet will not be as efficient as modern generation in effectively managing system stability in the presence of higher levels of variable generation but does have the advantage of limiting or reducing the cost of developing replacement generation.

Unit	Type/Fuel	Capability		Year Commercial	Age	Type of Operation
		Gross MW	Net MW			
Kahe 1	Reheat Steam/LSFO	86	82.2	1963	53	Baseload/Load Following
Kahe 2	Reheat Steam/LSFO	86	82.2	1964	52	Baseload/Load Following
Kahe 3	Reheat Steam/LSFO	90	86.2	1970	46	Baseload/Load Following
Kahe 4	Reheat Steam/LSFO	89	85.3	1972	44	Baseload/Load Following
Kahe 5	Reheat Steam/LSFO	142	134.6	1974	42	Baseload/Load Following
Kahe 6	Reheat Steam/LSFO	142	133.8	1982	35	Baseload/Load Following
Waiau 7	Reheat Steam/LSFO	87	83.3	1966	50	Baseload/Load Following
Waiau 8	Reheat Steam/LSFO	90	86.2	1968	48	Baseload/Load Following
Total Baseload/Load Following Capability		812	773.8	Average Age	46	
Waiau 3	Non-Reheat Steam/LSFO	49	47	1947	69	On-Off Cycling
Waiau 4	Non-Reheat Steam/LSFO	49	46.5	1950	66	On-Off Cycling
Waiau 5	Non-Reheat Steam/LSFO	57	54.5	1955	61	On-Off Cycling
Waiau 6	Non-Reheat Steam/LSFO	56	53.7	1961	55	On-Off Cycling
Total Cycling Capability		211	201.7	Average Age	63	
Waiau 9	Simple Cycle CT	53	52.9	1973	43	Peaking
Waiau 10	Simple Cycle CT	50	49.9	1973	43	Peaking
CIP CT-1	Simple Cycle CT	113	112.2	2009	7	Peaking
Total Peaking Capability		216				

Table D-87. Hawaiian Electric Current Dispatchable Generation

The "Baseloaded / Load Following" units average an age of 46 years while the on-off cycling units average 63 years of age. The combined average age of all steam units is 52 years. The existing generation fleet does well in serving stable consistent loads that are predictable. Hawaiian Electric also maintains two units (Honolulu 8 and 9) in a deactivated state. The units are not available to serve the system load without undergoing a reactivation process with would take months.

The existing generation fleet will need to meet the following future requirements.

- Improved ramp rate needs
- Improved turn down or on-off cycling
- Voltage Support
- Regulation

Ramp Rate

The variable nature of wind and solar require that the existing generation fleet react as the wind and solar change output. This function will be necessary until replacement generation or other technologies are serving the system.

Traditionally the existing baseload/load following units could provide a total ramping capability of 20.2 MW per minute. Combined with the cycling units, the steam units provide a total ramp rate of 33.6 MW per minute.

In order to improve the ability of the existing steam generating fleet to serve the system needs, Hawaiian Electric has been working to improve the ramp rates of the existing units.

Unit	Current Normal Ramp Rate (MW/min)	Proposed "Future" Normal Ramp Rate (MW/min) (3)
Kahe 1	2.3	4.0
Kahe 2	2.3	4.0
Kahe 3	2.3	5.0
Kahe 4	2.3	5.0
Kahe 5	2.5	4.0
Kahe 6	2.5	4.0
Waiau 7	3.0	4.0
Waiau 8	3.0	4.0
Total Load Following Ramp rate	20.2	34.0
Waiau 3	0.9	0.9
Waiau 4	0.5	0.5
Waiau 5	3.0	3.0
Waiau 6	3.0	3.0
Total Steam Unit Ramp Rate	27.6	41.4

Table D-88. Ramp Rates of Current Hawaiian Electric Generation

The improved ramp rates have been tested over the years at all Hawaiian Electric units. The implementation issues revolve primarily around adjusting control system functions to allow for automatic operation at higher ramp rates.

Turn Down and On-Off Cycling

The existing units have traditional minimum loads based on being able to respond to system disturbances and achieve full load anytime necessary.

However, as renewable penetration increases, it will be advantageous for existing steam units to improve turn down (reduce minimum load) or cycle online and offline. The general concept is that every MW reduced from thermal generation equals a MW more cost effective renewable energy integrated on the system.

Reducing minimum load has some advantages over on-off cycling. When online and at minimum loads, the units still provide necessary services to the system:

- Inertia
- Voltage Regulation
- Frequency Regulation
- Short circuit current
- Some ramping capability
- Some ability to respond to system disturbance

Compared to on-off cycling, low load operation allows for:

- Quicker return to full load capability
- Lower long term maintenance cost

Hawaiian Electric has tested and confirmed that low load and cycling goals set forth in the original PSIP are achievable. Currently, system load dispatchers have the ability to reduce three units to the new 5MW load when necessary to integrate additional renewable energy. The other units are expected to be ready for low load operations by 3rd quarter 2016.

Unit	Traditional Min Load (MWg)	New Minimum Load (MWn)	Restoration time from new min to full load capable (hours)	Cycling time from hot shutdown to full load capable
Kahe 1	25	5	1.5	3.5
Kahe 2	25	5	1.5	3.5
Kahe 3	25	5	1.5	3.5
Kahe 4	25	5	1.5	3.5
Kahe 5	45	25	1.5	3.5
Kahe 6	45	N/A	1.5	3.5
Waiau 7	25	5	1.5	3.5
Waiau 8	25	5	1.5	3.5

Table D-89. Hawaiian Electric Generation Unit Low Load and Cycling Targets

Minimum load reductions are accomplished by implementing hybrid variable pressure control operations. In order to maintain critical operating parameters in specification the units' throttle pressure is reduced when generating load drops below 30 MW

(Kahe 1–4, Waiau 7/8). The pressure is reduced linearly from 1,800 psig at 30 MW to 900 psig at 10 MW. When load is below 10 MW pressure remains at 900 psig.

This offers certain advantages over cycling the units off line:

- Reduces thermal stress to the turbine rotor and casing.
- Generation is reduced to a minimum to take more renewable energy.
- Provides system inertia.
- Provides short circuit current in the event of a system fault.
- Provides MVAR capacity and voltage support.
- Time to full load capability is less when compared to a unit startup.

Figure D-72 shows the ability of a unit to reach full load from its old minimum compared to the 5 MW minimum

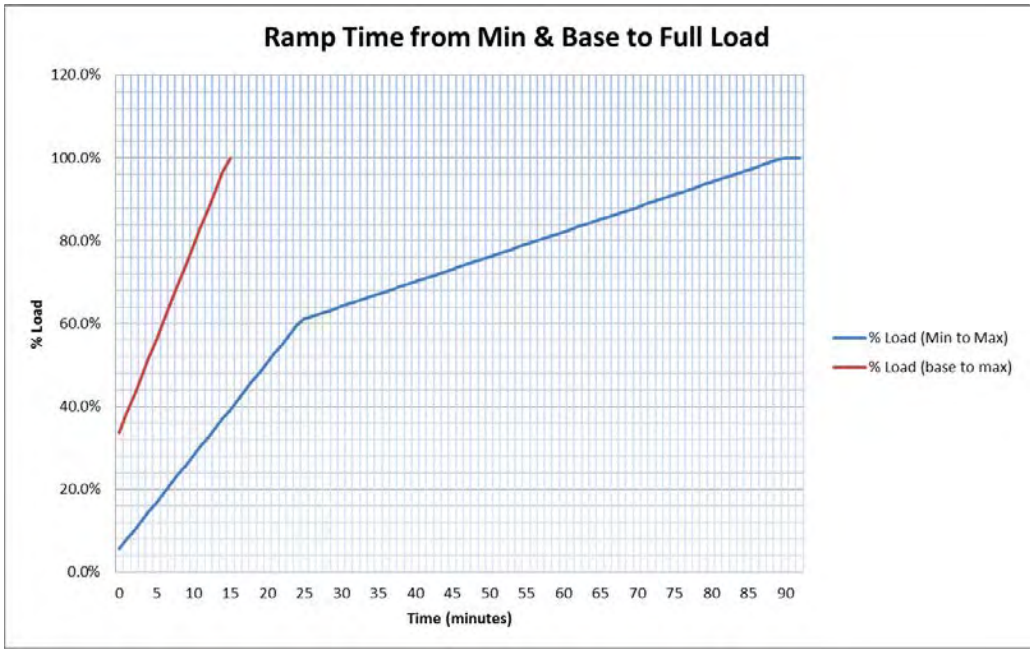

Figure D-72. Ramp Time from Minimum and Base Loads to Full Load: Hawaiian Electric

Generation Fleet Summary

Hawaiian Electric has expanded the capabilities of the existing generating units to support the changing electric system. However, these modifications to existing operations require tradeoffs. Reducing unit minimum loads allow for increased renewable generation on the system, but the ramp rates of the units will be reduced.

The existing units operating at low load and/or cycling will also have increased maintenance cost associated with greater and more frequent thermal cycles. Many components are analyzed and designed to last a specific number of cycles. At the average

age of 52 the units have already experienced many thermal cycles. Low load operation and/or cycling will be successful but at a cost. There will be increased maintenance and breakdowns as a result.

Hawaiian Electric understands the impacts to the units from increased thermal cycles. Hawaiian Electric is optimizing procedures and reviewing practices and options to minimize cost and maximize reliability with low load and cycling operations. Hawaiian Electric continues to review options to reduce or minimize cycling related damage. Being an island system, it will be important to effectively manage the impacts of cycling and low load operation.

Figure D-73 is from the National Renewable Energy Laboratory(NREL) of the U.S. Department of Energy report titled Cost of "Cycling Power Plants" dated 2012 demonstrates higher forced outage rates resulting from cycling operation. The report also concluded that cost associated with cycling and increased load following events would drive future maintenance cost higher.

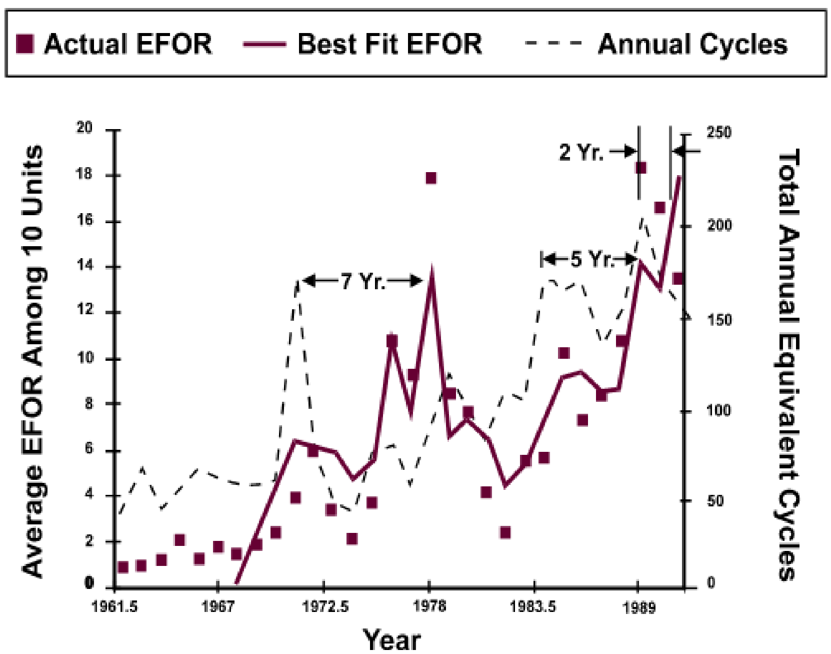

Figure D-73. Forced Outage Rates from Cycling: U.S. Averages

In addition to maintenance and reliability issues, the units will be less efficient. Efficiencies associated with startup and low load operation are lower than normal operations.

With an average age of over 52 year the existing steam units will need continued capital investments in order to continue to provide reliable service.

Analysis was conducted to demonstrate what investment would be necessary in order to run the existing units out to 2045.

The analysis shows that a capital investment of $935M to keep the units running to 2045. Investments would include:

- Replacement of major boiler pressure components
- Replacement of major turbine components
- Controls replacements
- Excitation replacements
- Replacement of old motors/pumps
- Replacement of critical valves
- Replacement of critical balance of plant components

The development of the project work list that would be required to keeping the units running to 2045 was based on a review of condition assessment, component maintenance history, and review of industry experiences. The budgetary costs were created based on reviewing similar projects and using industry standards.

In the years to come our peaking and cycling units will continue to fulfill those roles. Our baseloaded/load following units will be assuming new roles in supporting the system. During periods of high renewable generation (that is, high solar days) some of our reheat units will need to be cycled offline while others will be at new low loads.

The existing steam generating fleet will serve our customers in an increasing dynamic way for the years that follow. Hawaiian Electric will maximize the flexibility of the existing units to support transition to 100% renewable while considering potentially more cost effective and beneficial solutions.

Maui Electric Existing Generation

The existing dispatchable generation fleet on Maui includes:

- Quick/Fast start internal combustion engines (ICE) that providing emergency replacement power and peaking generation, and are higher cost than the larger resources.
- Combined cycle (CC) units, comprised of (two combustion turbines (CTs), two heat recovery steam generators (HRSG) and one steam turbine (ST)) that provide with high efficiency and relatively low cost, which provide cycling capability with a 1–2 hour start time, and have fast ramping capability. response.
- Older conventional steam units with limited cycling and load ramping capability that are schedule for retirement by 2024 because of permitting.

- These generating assets, combined with DR resources and DER, provide the flexibility necessary to integrate more intermittent renewable resources to meet 100% RPS requirements.

The Maui based dispatchable generating fleet is comprised of:

Unit	Type/Fuel	Capability Net MW	Year Commercial	Age	Type of Operation
Ma'alaea 14 to 16 Combined Cycle	2 – GE LM2500 CT with ABB ST /LSD (future LNG)	58	1992, 1992–1993	24, 23, 23	Baseload, Load Following
Ma'alaea 17 to 19 Combined Cycle	2 – GE LM2500 CT with MHI ST /LSD (future LNG)	58	1998 / 2000 / 2006	18/16 /10	Load Following/ Cycling
Total fast start, high capacity factor generation		116	Average Age	19	
Kahului 1	Non-Reheat Steam/IFO	5	1948	68	Reserve Shutdown
Kahului 2	Non-Reheat Steam/IFO	5	1949	67	Reserve Shutdown
Kahului 3	Non-Reheat Steam/IFO	11.5	1954	62	Baseload, Load Following
Kahului 4	Non-Reheat Steam/IFO	12.5	1964	52	Baseload, Load Following
Total cycling generation		34	Average Age	62	
Ma'alaea 1 to 3, X1, X2	GE EMD 20-645 ICE/LSD	5 @ 2.5	1971 – 1972 (X1/2 1987)	44, 45 (29)	Peaking
Ma'alaea 4 to 9	Cooper/Colt PC2-16/LSD	6 @ 5.6	1973-1978	38-43	Peaking
Ma'alaea 10 to 13	Mitsubishi /MAN 18V52/55A /LSD	4 @ 12.5	1979-1989	27–37	Peaking
Total Peaking Capability		96	Average Age	38	

Table D-90. Maui Electric Generating Units

Key (Types of Fuel): LSD – low sulfur diesel, IFO – intermediate sulfur fuel oil

Requirements for the Existing Dispatchable Generation

The existing generation on Maui provides operational flexibility to support the integration of more intermittent renewable energy resources to meet 100% RPS requirements. These assets have the following attributes:

- Low minimum operating load and/or cycling capability
- Quick-start capability
- Load following and ramping capability
- Black start capability

Combined Cycle Generation Assets

The combine cycle (CC) units support the build out variable renewables resources needed to achieve the 100% RPS goal by 2045. The combined cycle units consist of Ma‘alaea units M14/15/16 is a combined cycle unit consisting of two 21MW GE LM2500 combustion turbines, two natural circulation heat recovery steam generators and one 16MW ABB steam turbine. Ma‘alaea units M17/18/19is a combined cycle unit consisting of two 21MW GE LM2500 combustion turbines, two once through steam generators, and one 16MW Mitsubishi steam turbine.

These units support the system in several ways.

Support of Renewables. They provide flexible generation and economic bulk supply of energy demand.

- The M17/18/19 units are designed for cycling and supporting the ramping needs of the system. The units are limited by permit constraints to two starts per day. From the time a start is initiated the combustion turbines can be online in 25 minutes.
- The M14/16/17 units are being modified to better support low load operation. The combustion turbine can be online in 25 minutes.
- The M17/18/19 units can be cycled offline as necessary, with a 1 to 2 hour startup and three hour minimum down time.
- The units are capable of relatively fast ramping (2 MW per minute) and a minimum dispatch limit of 25%, driven by the covered source permit and 60% based on minimum steam flow through the once through steam generator.

Support of High Run Hour Generation

- The combined cycle units with a heat rate between 8,330 Btu/kWh – 8,525 Btu/kWh provide generation at high efficiencies making them well suited for bulk customer service needs that will be required until the required variable/firm renewables are built out.
- Because of this high efficiency, they are well suited to consume biodiesel after 2045 to support the 100% RPS target and minimizing the impact on customer bills

Cycling and Startup Costs. while the LM2500 combustion turbines do not incur a startup cost, the heat recovery steam generator and the steam turbine are impact by cycling. This cost is included in the production cost modeling.

- The LM2500 combustion turbines which are part of the Ma‘alaea CC unit have bypass systems which allows for faster starts with minimal startup cost impact.

Long Term Reliability and Maintenance. The CC units were evaluated for continued operation to 2045. An estimated capital expenditure of $113.5M was deemed necessary to support long term operations. The capital expenditures represent capital investment over what is normally included in scheduled overhaul cycles. The expenditures were calculated based on units running to 2045 and were based on a review of condition assessment, component maintenance history, and review of industry experiences. The budgetary costs were created based on reviewing similar projects and using industry standards. The identified investment generally include:

- Replacement heat recover steam generator pressure components
- Refurbishment of generators stators and rotors
- Excitation system upgrades
- Transformer and electrical system upgrades
- Replacement of major pumps/motors
- Upgrade to obsolete control systems

Quick/Fast Start Peaking Generation Assets

The quick/fast start peaking generation units support the build out variable renewables resources needed to achieve the 100% RPS goal by 2045.

The peaking units consist of:

- The Maʻalaea units M1, M2, M3, X1, and X2 are 20-EMD-645 ICE units built in the 1970s and 1980s.
- The Maʻalaea units M4, M5, M6, and M7 are Cooper PC2-16 ICE units constructed in the mid-1970s with an individual max load of 5.6 MW. Units M8 and M9 are Colt-PC2-16 diesel engines constructed in the late 1970s with an individual max load of 5.6 MW.
- The Maʻalaea units M10, M11, M12, and M13 are Mitsubishi Heavy Industry ICE units manufactured by MAN of Germany, model 18V52/55A constructed between 1979 and 1989 with an individual maximum capacity of 12 MW.

The Internal Combustion Engines (ICE) provide 96 MW of quick/fast start capability.

Support of Renewables and Load Loss. The various types of ICE units support the variable renewable generation differently.

- The GE EMD ICE units (2.5 MW units) are quick start and can be at full load in less than 10 minutes. These units will support renewable generation because they are offline reserve generation that can be deployed in response to cloud cover or wind events resulting in un-forecasted losses of variable generation.
- The Cooper PC2-16 units (5.6 MW units) can come online 15 minutes after a start signal is given. The units take an additional 50 minutes to reach full load. Current constraints limit dictate that the units need to be started sequentially rather than simultaneously. They serve the system best when used for compensating for

forecasted loss of variable generation and recovery following an event to supplement other sources generation.

- The MHI 18V52/55A ICE units (12.5 MW units) can come online 17 minutes after a start command is given and be at full load in 117 minutes. The serve the system best being available for forecasted lack of variable generation and supporting peak loads.

Cycling and Start-Up Costs. The ICE units have very low startup costs. They can be used to provide generation when only a small increment is needed, in lieu of starting a larger unit and operating them at an inefficient load-point. The ICE units are well suited for quick starting and numerous starts.

Long Term Reliability and Maintenance. Though some of these units are older, their modular design allows for continuous repair and overhaul extending their life through 2045 as long as parts are available. These types of units normally do not require any additional capital expenditures to extend their life to 2045.

- The GE EMD ICE units which were also used for diesel locomotive engines have a large user base resulting in long term availability of parts to maintain the engines.
- The Cooper PC2-16 ICE units also has large user base.
- The MHI ICE units are expected to be serviceable with replacement parts for many years to come as both Mitsubishi Heavy Industries and MAN continue to produce engines (different model) and maintain the engineering and facilities to produce parts for these engines.

Support of System Stability. While they supply load replacement very quickly, the ICE do not provide load flexibility and therefore do not support all type of system stability needs.

- The GE EMD ICE units (2.5 MW units) cannot be incrementally controlled through the SCADA/EMS system and are not used for regulation.

Maui Island Conventional Steam Generation Assets

Kahului Power Plant has four steam units. Kahului 1 and Kahului 2 are currently in a reserve shutdown status. Kahului 3 and Kahului 4 are baseloaded and currently operate at low loads while also providing a significant amount of online system regulating reserve. All steam units at Kahului will be retired by 2024 for environmental reasons.

With the retirement of the Kahului plan. There will be a need for replacement generation to continue to support the variable renewable resources and the system demand.

Lana‘i Generation Assets

The Lana‘i system is small in terms of size. Currently the island’s generation needs are met via six 1.0MW EMD diesel engines and two 2.2MW Caterpillar 3608 diesel engines.

In addition, there is a Caterpillar C32-1100 combined heat and power unit (CHP) on Lana‘i that provides 800 kW of power to the system and heat to support Manele Bay hotel loads.

As with the Maui units, the EMDs are expected to be serviceable well into the future as parts will remain available because of the large customer base.

The EMD units (Miki Basin 1–6) are capable of starting in less than 10 minutes. The units are well suited for responding to un-forecasted changes in variable generation.

The Caterpillar engines are more efficient than the EMDs are well suited for meeting system peaks and forecasted changes in variable generation. The Caterpillar 3608 engines can start and be online in 17 minutes and at full load in 22 minutes.

The size of Lana‘i's system with the flexibility of the current generation mix help support the transition to 100% renewables. The units will be able to compensate for changes in generation as well as supplement energy storage use.

Moloka‘i Generation Assets

The Moloka‘i system is small in terms of size. The generation fleet is currently made up of:

- Two 1.25 MW Caterpillar 3516 diesel engines
- Four 1.0 MW Cummings KTA50 diesel engines
- Three 2.2 MW Caterpillar 3608 diesel engines
- One 2.0 MW Solar Centaur T4001 combustion turbine

The engines on Moloka‘i have a large user base and expected to be serviceable with parts for well into the future.

The Caterpillar 3608 engines are more efficient than the other engines and are well suited for meeting system peaks and forecasted changes in variable generation. The Caterpillar engines can start and be online in 17 minutes and at full load in 22 minutes. This makes them ideal for efficiently supporting forecasted needs.

The flexibility of the generation fleet supports the transition to 100% renewable energy by providing quick starting and quick ramping to compensate for losses of forecasted and un-forecasted variable generation as well as supporting peak loads. The units are well equipped to support the transition to 100% renewable by providing grid services such as frequency and voltage control, meeting changes in generation need, and can be used to supplement energy storage as necessary.

Hawai‘i Electric Light Generation Assets

Hawai‘i Electric Light dispatchable generation fleet has included both utility-owned and independent power producer assets. The existing dispatchable generation fleet on Hawai‘i Island includes:

- Quick/Fast start generation including simple cycle combustion turbines (SCCT) and internal combustion engines (ICE) that providing emergency replacement power and peaking generation, and are higher cost than the larger resources. The simple cycle combustion turbines can be used as black start resources.
- Combined cycle (CC) units, comprised of (two combustion turbines (CTs), two heat recovery steam generators (HRSG) and one steam turbine (ST) with high efficiency and relatively low cost. These assets provide cycling capability with a 1–2 hour start time, and have fast ramping capability.
- Older conventional steam units have offline cycling capability, but longer start-up times and less ramping capability when compared to the combined cycle units.
- Geothermal IPP provides firm energy.

These generating assets, combined with DR resources and DER, provide the flexibility necessary to integrate more intermittent renewable resources to meet 100% RPS requirements.

The Hawaiian Electric Light dispatchable generating fleet is comprised of:

Unit	Type/Fuel	Capability Net MW	Year Commercial	Age	Type of Operation
Keahole Combined Cycle	2 – GE LM2500 CT with ST /LSD (future LNG)	56.3	2004/2009	12/6	Load Following/ Cycling/Frequency Regulation
HEP Combined Cycle	2 – GE LM2500 CT with ST /LSD (future LNG)	60.0	2000	15	Load Following/ Cycling
Total fast start, high capacity factor generation		116.3	Average Age	10	
Hill 5	Non-Reheat Steam/IFO	14.1	1965	51	Cycling
Hill 6	Non-Reheat Steam/IFO	20.2	1974	42	Cycling
Puna 1	Non-Reheat Steam/IFO	15.7	1970	46	Cycling
Total cycling generation		50.0	Average Age	46	
Kanoelehua CT1	GE Frame 5 SCCT/LSD	11.5	1962	54	Peaking
Keahole CT2	ABB GT-35 SCCT/LSD	13.8	1989	27	Peaking
Puna CT3	GE LM2500 SCCT/LSD	21.0	1992	24	Peaking
Kanoelehua	Fairbanks Morse ICELSD	2.0	1962	54	Peaking
Kanoelehua	GE EMD 20-645 ICE/LSD	3 @ 2.5	1972 - 1973	43	Peaking
Keahole	GE EMD 20-645 ICE/LSD	3 @ 2.5	1972	44	Peaking
Waimea	GE EMD 20-645 ICE/LSD	3 @ 2.5	1970-1972	45	Peaking
Mobile	Cummins ICE/LSD	4 @ 1.25	1984 -1988	30	Peaking
Total Peaking Capability		75.8	Average Age	40	

Table D-91. Hawai'i Electric Light Fossil Generating Units

Key (Types of Fuel): LSD – low sulfur diesel, IFO – intermediate sulfur fuel oil

Requirements for the Existing Dispatchable Generation

The existing generation on Hawai'i Island provides operational flexibility to support the integration of more variable renewable energy resources to meet the 100% RPS requirement. These assets have the following attributes:

- Low minimum operating load and/or cycling capability
- Quick-start capability
- Load following and ramping capability
- Black start capability

In addition, Hawai‘i Electric Light has potential firm renewable energy resources (biomass, geothermal) to help meet 100% RPS requirements.

Combined Cycle Generation Assets

The combine cycle (CC) units support increasing variable renewables resources incorporated to achieve the 100% RPS goal by 2045.

Support of Renewables. They provide flexible generation and economic bulk supply of energy demand.

- The units can be cycled offline as necessary, with a 1 to 2 hour startup and three hour minimum down time.
- The units are capable of relatively fast ramping (4 MW per minute) and a minimum dispatch limit of 30%–40%, driven by the covered source permit and minimum steam flow through the heat recovery steam turbine. Potential may exist to increase these ramp rates.

Support of High Run Hour Generation

- The combined cycle units are the most efficient conventional plants on the system, well suited for cost effective service of the bulk customer energy needs that will continue to be required until dependable replacement renewable resources are available to serve these needs.
- Because of this high efficiency, they are the most cost-effective resources for future fuel-switching to biodiesel to support the 2045 100% RPS target and minimizing the impact on customer bills.

Cycling and Startup Costs. while the LM2500 combustion turbines do not incur a startup cost, the heat recovery steam generator and the steam turbine may increase because of offline cycling.

- The LM2500 combustion turbines which are part of the Keahole CC unit have steam bypass systems which allows for faster starts than would be possible without the bypass. It also allows for faster startup in simple-cycle mode for emergency replacement power (22 minutes).
- The LM2500 combustion turbines which are part of the HEP CC unit do not presently have steam bypass systems but this will be pursued, to add flexibility will increase the support of future renewables as well as lower total cost and faster available replacement power.

Long Term Reliability and Maintenance. The CC units were evaluated for continued operation to 2045. An estimated capital expenditure of $113.5M was deemed necessary to support long term operations. The capital expenditures represent capital investment over what is normally included in scheduled overhaul cycles. The expenditures were calculated based on units running to 2045 and were based on a review of condition assessment, component maintenance history, and review of industry experiences. The budgetary costs were created based on reviewing similar projects and using industry standards. The identified investment generally include:

- Replacement heat recovery steam generator pressure components
- Refurbishment of generators stators and rotors
- Excitation system upgrades
- Transformer and electrical system upgrades
- Replacement of major pumps/motors
- Upgrade to obsolete control systems

Quick/Fast Start Peaking Generation Assets

The quick/fast start peaking generation units support the renewable resources needed to achieve the 100% RPS goal by 2045.

The Internal Combustion Engines (ICE) provides 27.5MW of quick start capability all available in less than 3 minutes.

Support of Renewables and Load Loss. These smaller resources quickly allow the system to meet lead requirements from:

- Loss of generating units or transmission lines.
- Variability in wind and solar resources because of changes in weather.
- Emergency peaking needs.

Costs. The ICE units have very low startup costs. They can be used to provide generation when only a small increment is needed, in lieu of starting a larger unit and operating them at an inefficient load-point. The ICE units are well suited for quick starting and numerous starts.

Long Term Reliability and Maintenance. Though some of these units are older, their modular design allows for continuous repair and overhaul extending their life through 2045 as long as parts are available. These types of units normally do not require any additional capital expenditures to extend their life to 2045.

- The GE EMD ICE units which were also used for diesel locomotive engines have a large user base resulting in long term availability of parts to maintain the engines.
- The Fairbanks Morse ICE unit has a similar large user base.

The simple cycle combustion turbines (SCCT) provide 46.3MW of peaking capability. The simple cycle turbines are used for emergency replacement reserves and peaking energy.

Support of Renewables and Loss of Load. The simple cycle combustion turbines have fast start capability (5–22 minutes) which is not as quick as the ICE units but faster than combined cycle and steam unit startup.

Costs. The cost varies between the different types of SCCT units.

- The GT-35 and Frame 5 have a high heat rate, and accordingly, high production costs. These units have the shortest startup times of the gas-turbines, in less than 10 minutes. They do incur a maintenance cost for each start, but because of the high production costs do not incur many starts per year. They are operated primarily for emergency replacement power and short-term energy needs.
- The GE LM2500 does not incur a significant maintenance cost for starts. These can be started as needed to support the system needs. These units are relatively efficient; second only to the combined cycle operation for the fleet. These units therefore are used for short-term energy needs, in lieu of starting a combined cycle or steam unit for a short term need, in addition to emergency replacement power.

Long Term Reliability and Maintenance. These combustion turbine units are 24 to 54 years old. Their modular design allows for continuous repair and overhaul extending their life through 2045 as long as parts are available. With limited operation hours, these types of units normally do not require any additional capital expenditures to extend their life to 2045.

- Though 54 years old, the GE Frame 5 SCCT have a large user base resulting in long term availability of parts to maintain this turbine. This type of turbine is still being manufactured today which allows for potential upgrades.
- The GE LM2500 SCCT is 24 years old. It also has a large user base and is still being manufactured today. This type of combustion turbine is shared with the combine cycle unit at Ma‘alaea, Keahole, and HEP.
- The ABB CT35 SCCT is 27 years old and has much smaller user base. Maintaining this combustion turbine may prove more difficult in the next 20 to 30 years. The assumption is that it will be maintained until 2045.
- All the simple cycle combustion turbines have the capability to operate in isochronous control (zero-droop or swing unit) for frequency control and stability during major system disturbances and restoration.
- CT2 is located in Keahole, which allows it to support the minimum generation requirement for West Hawai‘i generation for voltage and transmission system constraints.

Conventional Steam Generation Assets

The conventional steam provide many benefits. Hill 5 and Hill 6 provide 14.1 and 20.2 MW of steam generated electricity. The Hill 5 and Hill 6 plants are 51 and 42 years old respectively. The Puna Steam Generating plant has been operating for seasonal cycling operated during low generating capacity margins. It may shortly operate on a schedule for the peak periods, as the present availability of low-cost fuel has made the unit cost-competitive for operation compared with combined cycle assets.

Support of Renewables. Because the small size of these steam units, they provide greater dispatch flexibility than larger steam units.

- The units can be cycled offline with a minimum 3 hour start time for warm start. With present equipment and controls, these units require extensive manual operation during startup and startup time may be shortened if equipment is modified.
- The units have a lower minimum dispatch limit than combined cycle units, but a smaller dispatch range.
- These conventional steam units have a sustained ramp rate of 2-3 MW per minute. While presently satisfactory, this may not be sufficient for future higher penetrations of variable solar and wind, requiring supplement from other ramping resources.
- Provides firm capacity.
- The steam units are significantly less efficient than the combined cycle units.
- Because of this low efficiency, they would no longer be cost-effective using biodiesel after 2045 to support the 100% RPS target

Cycling and Startup Costs. The equipment of the entire conventional steam plant is impact by cycling. This cost is included in the production cost modeling

Long Term Reliability and Maintenance. An evaluation was done to calculate the capital investment necessary for the three (3) conventional steam units to support the Hawai‘i Electric Light system until 2045. It is expected that an investment of $49M will be necessary for reliable operation. The expenditures were calculated based on units running to 2045 and were based on a review of condition assessment, component maintenance history, and review of industry experiences. The budgetary costs were created based on reviewing similar projects and using industry standards. Generally the capital investments include work over and beyond what is normally done during the overhaul cycle and includes:

- Replacement of major boiler pressure components
- Replacement of major turbine components
- Refurbishment of generator stator and rotor
- Replacement of excitation systems

- Transformer and electrical system replacements
- Replacement of major pumps/motors
- Replacement of critical piping and valve
- Upgrade to obsolete control systems

Operations of the Conventional Steam Generation Assets

The selection of which large units will operate to serve the majority of demand is

- Made on the basis of meeting the minimum system security requirements,
- Considering the available resources capable of meeting those requirements, and the
- Overall production cost. The combination that can provide acceptable system security at the lowest cost will be used.

For system security and reliability, system security analysis has identified that at present the system can generally operate with acceptable reliability with a minimum of four of the existing larger units online. These units can be any combination of one of

- The three steam units, and/or
- The LM2500 units, in simple or combined cycle. A plant operating in combined cycle counts as two units to the minimum four unit requirement.
- At least one of the units must be located at Keahole because of voltage and transmission security constraints.

AVAILABLE RESOURCE OPTIONS AND THEIR COSTS

For the 2016 updated PSIP analyses, we have taken a "clean sheet" approach in developing new resource options. In developing this new set of assumptions, the Company was mindful of the Commission's concerns[36] expressed in Order 33320, summarized as follows:

- The Commission expressed concern that the 2014 PSIPs relied "heavily" on "… renewable resources with relatively high costs and unproven resources with uncertain feasibility."[37]
- The Commission was concerned that "… the amounts and types of renewable resources that are considered in the PSIP analyses appear to be inappropriately limited. Generally, the Hawaiian Electric Companies' criteria for exclusion of resource technologies from consideration in the economic analyses based on the state of commercial readiness appear over-restrictive."[38]
- The Commission also stated that, "… the technology cost assumptions utilized by the Hawaiian Electric Companies in the PSIPs also appear conservative" and "…do not appear to accurately reflect current cost trends …"[39]

Specific PSIP Assumptions Related to New Utility-Scale Resources

The specific assumptions regarding new utility-scale generating resources are contained in Appendix A. One of the key differences from our 2014 PSIP assumptions is the use of multiple sources of forward curves for the capital cost of new generating technologies and new energy storage technologies. Figure D-74 is a graph showing the projections of per unit capital costs (expressed in $/KW) in constant 2016 $. The data portrayed are the underlying constant $ projections that underlie the nominal dollar assumptions utilized

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[36] Order No. 33320, Concerns 2.a., 2.b, and 2.c. at 66–86.

[37] *Ibid.* at 80.

[38] The Commission correctly points out in Order No. 33320 at 83 that technologies with a CRI Level 4 are in full-scale commercial use and have "publicly verifiable data on technical and financial performance." However, the full description of CRI Level 4 as provided in Table H-1 of the 2014 Hawaiian Electric Company PSIP, also included criteria related to the ability of these technologies to be financed. In particular, CRI Level 4 technologies"… may still require subsidies…" That description of CRI Level 4 also stated that there is"…interest from debt and equity sources…" although CRI Level 4 technologies may"… still [require] government support." The Companies cut off the technologies to be considered in the 2014 PSIPs based on the ability of the technology to receive financing without the need for subsidies, and to avoid relying heavily on technologies which have "high costs and uncertain feasibility". As noted in the PSIPs at page H-1,"…this planning assumption is for the PSIP analyses only, and does not affect our intent to thoughtfully consider specific projects that include emerging technologies. In other words, we welcome generating technologies not considered in the PSIPs that are proposed in responses to future request for proposals (RFP) for any of our power systems." We reiterate that intent here.

[39] *Op. cit.*, at 85.

in the updated 2016 PSIP analysis. The constant dollar projection is a useful way to portray the expected future cost trends of various electric power generation technologies.

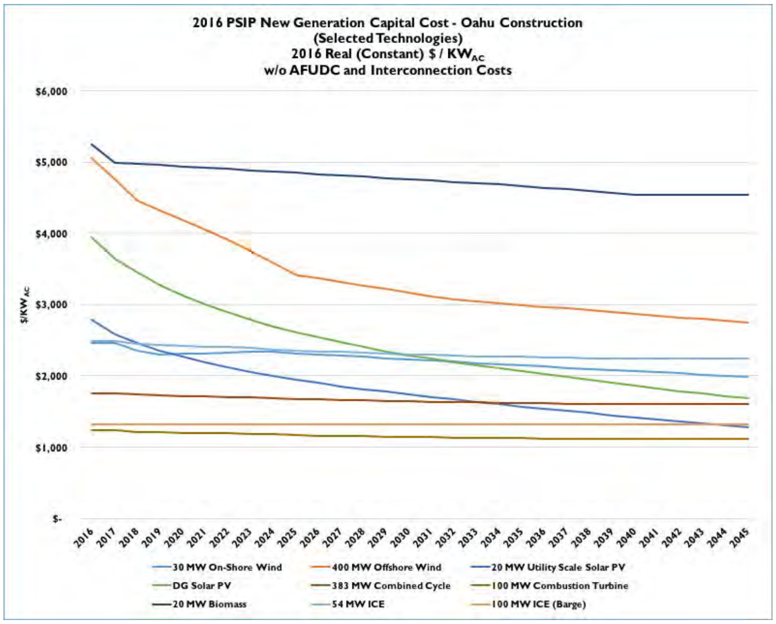

Figure D-74. 2016 PSIP Utility-Scale Generating Resource Capital Costs—O‘ahu

Sources of Data to Develop New Utility-Scale Generating Resource Assumptions for PSIP

As noted above, in response to the Commission concerns, the Company has undertaken a complete re-work of the resource technologies and cost assumptions to be utilized in the 2016 PSIP updates. At the time of this interim filing, work continues to refine these assumptions.

The re-working of the new resource assumptions started with a review of current literature and data sources including:

- National Renewable Energy Laboratories' (NREL) *2015 Annual Technology Baseline* spreadsheet (July 2015)[40]
- *Lazard Levelized Cost of Energy Analysis – Version 9.0* (November 2015)[41]
- Energy Information Administration's *Updated Capital Cost Estimates for Utility-Scale Electricity Generating Plants* (April 2013)[42] (used primarily as guidance for regional cost adjustments)

[40] The NREL ATB spreadsheet is available at: http://www.nrel.gov/analysis/data_tech_baseline.html.

[41] The Lazard analysis is available at: https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf.

[42] The EIA report is available at: http://www.eia.gov/forecasts/capitalcost/.

- Electric Power Research Institute (EPRI) *Technology Assessment Guide* (2013-2015 data sets), a proprietary[43] data based of power technology costs and performance
- Various proprietary reports published IHS Energy in 2015 regarding cost trends related to solar PV, wind, and energy storage technologies
- *Gas Turbine World 2014-15 Handbook*, a publication for purchase (the cost is approximately US $200) that provides power plant prices, price trends, and performance data for combustion turbines and combined cycle plants
- RSMeans data. RSMeans publishes proprietary indices regarding materials, labor and productivity for more than 900 cities in the US and Canada, including Honolulu, Hawai‘i and Hilo, Hawai‘i
- NextEra Energy, Inc.’s (NextEra) internal estimating capabilities with respect to simple-cycle combustion turbines, combined-cycle power stations, and small internal combustion units
- Vendor indicative quotes provided to NextEra (in the case of HVDC inter-island cables)
- Company’s internal data and estimates for the cost of Internal Combustion Engine units, including the actual budgeted costs for the Schofield Generating Station (as proposed in the Company’s application in Docket 2014-0113 and reduced to reflect favorable movement in foreign exchange rates), and a vendor quote for the 100 MW ICE “power barge” proposed for installation of O‘ahu
- Company’s internal estimates of system interconnection costs for resources of various sizes (this includes only the cost of connecting to the grid; these estimates exclude any costs associated with system upgrades that might be required to accommodate a specific project)

In addition to the sources listed above, the Companies actively solicited input from the Parties in Docket 2014-0183 regarding new resource options.

- In the November 25, 2015 PSIP work plan filing, the Companies expressly solicited input from the parties to Docket 2014-0183 regarding specific resource costs and constraints;

[43] “Proprietary” means that the materials, analysis, and data are trademarked, privately-owned, private, patented, or otherwise exclusive to the party which produced the information. Generally, any party willing to pay for a license right to use the information may obtain it. To the extent the Company employs such resources, it is bound by the terms of the license or right agreement. This is a common commercial practice across a number of industries.

- Both before and during a Company-sponsored roundtable discussion with parties on December 17, 2015, the Company reiterated its request for input regarding specific resources that should be considered in the PSIPs.
- At the January 7, 2016 Commission-sponsored Technical Conference, the Company once again solicited input regarding new resource options.

As a result of these requests, two parties did approach us with specific information regarding projects that they are sponsoring. The information provided by these parties was compared to other independent data sources and validated. Thus, certain of the resource capital cost assumptions are reflective of input from those parties.

In Order No. 33320, the Commission itself "… encouraged (the Parties) to offer specific recommendations or analyses that will assist in the development of the Hawaiian Electric Companies' supplemented, amended and updated PSIPs." In the Parties' respective January 15, 2016 responses to the Commission's encouragement, several parties offered their opinions and suggestions regarding resource types that they would like to be considered. However, were unable to find any specific numerical / objective data in the comments of the Parties that could be used for inputs to the Companies' PSIP modeling efforts. Notwithstanding the lack of useable modeling data from the Parties' January 15, 2016 filings, most of the resource types suggested by the Parties are being considered and addressed by the Companies in this PSIP update effort. In addition, and as noted above, the Companies were approached by certain parties who offered specific input that was incorporated.

Utility-Scale Generating Resource Assumptions Development Process

The process of developing the resource assumptions involved several different efforts. These efforts were synthesized into a common set of assumptions for use in the 2016 PSIP update analysis. These different efforts included:

- The Companies conducted its own research and review of the various data sources, with an emphasis on utilizing the most current data sources possible. The NREL ATB database was one such current source. A significant advantage of the NREL ATB data source is that it provides a publicly available source of the forward curves for capital expenditures and operations and maintenance expenses for several different power generation technologies. This data was combined with the U.S. Department of Energy Information Administration's (EIA) 2013 *Updated Capital Cost Estimates for Utility-Scale Electricity Generating Plants* information regarding locational adjustments (by technology) and specifically for Honolulu, Hawai'i, to adjust the NREL ATB data for Hawai'i. Further adjustments were made to the cost data to adjust to 2016 $ as the base year for the 2016 PSIP update. A 1.8% inflation / escalation rate was utilized to adjust to 2016 $. In addition, all cost information was converted from real (constant $) to nominal (as-spent) dollars using the same 1.8% inflation and escalation rate. Nominal dollars are used in the PSIP economic analysis to evaluate various cases in the PSIP analysis. The Company's own analysis and conclusions incorporated input from certain Parties to this proceeding in response to the Company's open invitation for input at described above.

- NextEra Energy, Inc. (NextEra) provided consulting services to the Company in the new resource assumption development effort. NextEra has extensive experience as a developer, owner and operator of wind power, solar PV projects, solar CSP projects, gas-fired generation stations, and bulk energy storage projects. With respect to onshore wind, solar PV and energy storage, NextEra utilized the services of IHS Energy's proprietary research reports to develop initial cost assumptions for certain resources. IHS reported information for development of renewable resources and energy storage specifically for California. Further IHS also provided forward curves for various resources. The California reference was adjusted to a Hawaiʻi value based on the RSMeans' city indices for materials, labor and productivity. Importantly, NextEra *then* compared the results of the Hawaiʻi-adjusted data to its own experience in the development and operation of some of the technologies considered, including projects in Hawaiʻi .[44] The result is a set of cost values for the various technologies that reflect independent evaluations *and* actual experience. All prices were adjusted for Hawaiʻi by applying a 4% adder for Hawaiʻi General Excise Taxes.

In addition to the parallel efforts by the Company and NextEra, NREL was retained as a consultant to provide an independent and objective review of the assumptions synthesized through the processes previously described. The NREL report was received just as this filing was being finalized and will be included as part of the Updated PSIPs.

Notwithstanding the foregoing sentence, we would respectfully inform the Commission and the Parties that changes to these assumptions could occur after this filing. Our goal is to develop a set of new resource assumptions that is as objective as possible. We will promptly notify the Commission and the parties of any changes made to the resource assumptions.

[44] On February 4, 2014, *Pacific Business News* published an article entitled "NextEra Provides Cost Estimates for Hawaiian Electric's New Energy Plans." The author of this article did not contact the Company prior to publishing the article. We believe the article is potentially misleading as it suggests that NextEra provided numbers that were utilized by the Company in its analysis without any vetting or independent review by the Company. As described herein, the process of arriving at the new resource assumptions was a collaborative process involving the independent data sources, and collaboration by the Company, NextEra and NREL. In addition, the Companies utilized an outside consultant to manage the compilation of resource assumptions and to assure consistency and objectivity around these assumptions.

Technologies Available for PSIP Optimization Analyses for Interim Filing Purposes

As noted above, the Commission recognized that actionable plans cannot be built on the hope that "unproven" resources as of today will become available at costs that make them feasible in the future. At the same time, the Commission has asserted that the choice of technologies used in the 2014 PSIPs were "overly restrictive." Respectfully, we found the guidance provided in these two areas to be conflicting.

In order to resolve this conflicting guidance, we went back to the Commission's statements regarding the purposes of the PSIPs. Specifically, in Order No. 33320, the Commission stated that one of the purposes of the PSIPs is to "… address the need for applications for approval of individual capital projects, programs, contracts and RFP's to be considered with the benefit of the context provided by well-vetted, sufficiently analyzed comprehensive system plans."[45] In determining our approach to the new resource assumptions, we placed substantial weight on this statement by the Commission, which has been interpreted to mean that the PSIPs are to serve as the basis for actionable, near-term decisions. In particular, the PSIPs should identify specific decisions that must be made in the near term (for example, 2–3 years) by the Commission regarding approvals for RFPs to solicit resources to meet capacity needs, applications for capital expenditures related to power supply and energy storage projects, and applications for PPA approvals.

We do not believe that it is in the best interest of our customers to ask them to underwrite the risks associated with technologies that are not commercially available today. This is particularly true with respect to the Commission's direction, and the Company's full intention, to provide a detailed near-term roadmap. One of the goals of our Preferred Plan will be to provide the optionality and flexibility over the *long-term* to accommodate technology and cost improvements in existing technologies, and to accommodate the commercialization of transformational technologies that might become available in the future. We strongly believe that this is a prudent and reasonable philosophy that is in the best interest of customers. It is also in the best interest of achieving the state's renewable energy policy goals to avoid large bets on unproven technologies, the failure of which could actually impede or delay achievement of 100% RPS.

Notwithstanding the forgoing, we reiterate and expand here on our position stated in the 2014 PSIP filings: the initial choice of technologies for consideration is a planning assumption *and is in no way intended to limit or discourage proposals for other technologies.* However, such proposals must have the following attributes:

- Sound engineering design concepts;

[45] Order No. 33320 at p 39.

- Commercial availability of the technology from a reputable vendor who will stand behind the performance and servicing of the technology (including all balance of plant items) over its useful life;
- Demonstrated financial feasibility of the project employing the technology, including its benefits to ratepayers, taking into account the system needs (as stated in a competitive bidding process approved by the Commission, or as stated in a waiver from the competitive bidding framework approved by the Commission) and the costs of integration.
- The ability of the project sponsor to demonstrate the financial wherewithal and technical capabilities to successfully finance, construct and operate the project employing the technology.

Giving weight to the need for near-term actionable guidance and further giving weight to the need to avoid building near-term plans that rely "heavily" on unproven technologies, the initial PSIP new resource analysis choices were limited to the following:

Solar Photovoltaic (PV). Solar PV technology is a mature technology. Current forecasts for this technology are characterized by continuing modest decline in capital costs and incremental improvements to the technology. There are multiple utility-scale solar PV projects installed in Hawaiʻi. There is significant experience in the Hawaiʻi market with solar PV technology by the Company, multiple project developers, and capital providers.

The PSIP assumptions reference fixed tilt systems (as opposed to single-axis and multi-axis tracking systems). The PSIPs utilize capacity factors and output profiles for utility-scale solar are based on historical experience with existing utility-scale solar PV systems. Costs for solar PV systems are typically expressed in $ per watt of the total output of the PV system panels, which is direct current power. The ratios of DC output to (usable) AC output in utility-scale solar PV projects typically ranges from 1.1 to 1 to 1.5 to 1. For purposes of this PSIP, the reference plant modeled assumes a 1.5 to 1 DC to AC ratio. This is also based on NextEra's experience with development of multiple utility-scale solar PV systems.

Onshore Wind Power. Similar to solar PV, onshore wind projects employ mature technology. Wind power trends are characterized by modest decreases in per unit capital cost (in real terms), modest performance increases, and substantial improvements in the size of single wind turbines that are available in the commercial market. There is over 200 MW of wind capacity installed and operating in the Companies' service areas, almost all of it owned by independent power producers. There is significant experience in the Hawaiʻi market with solar PV technology by the Company, multiple project developers, and capital providers.

Wind projects exhibit significant economies of scale, because of the intensive mobilization effort (for example, heavy cranes, equipment to move towers and turbines from port to the site location). The cost assumptions used in the PSIPs reflect these economies of scale.

Combustion Turbines (CT). Modern combustion turbines are the "workhorse" of electric utility systems around the world. Essentially jet engines coupled to a generator, CTs can be designed to utilize a variety of fuels including fuel oil, naphtha, and natural gas. CTs are characterized by relatively low capital costs, modest efficiency (heat rates on the order of 10,500 BTU per kWh), high reliability, and relatively short lead times for installation. CTs are a mature technology with projected flat capital cost (in real terms) and continued small incremental performance improvements over time.

Smaller CTs typically are less efficient than larger machines (heat rates as high as 18,000 Btu/kWh for small "microturbines." CTs have significant operating flexibility with fast-start capability, fast ramping, and a high level of variability when spinning. CTs are typically used in peaking applications, where capacity is required to meet short duration peak demands. Typical annual capacity factors for CTs are less than 20%, sometimes significantly less. CTs can play an important role in the integration of variable renewables by providing capacity and energy at times when the variable renewable resources may be limited by cloud cover and/or poor wind conditions.

There are several very large, well-capitalized international vendors who provide CTs in a variety of sizes. Each of these vendors has extensive supply chains for parts and service. There capabilities are supplemented by numerous specialized O&M service firms and after-market parts suppliers. There is a vast amount of experience on the part of utilities (including the Hawaiian Electric Companies and NextEra), IPP project developers, and providers of capital with CTs.

Combined-Cycle. Combined-cycle power plants are a mature technology that employ CTs, but add a heat recovery steam generator (HRSG) that takes the exhaust heat from one or more CTs, "recover" the thermal energy that that would otherwise go to waste, and make steam. The steam is then used to turn a steam turbine coupled to a generator. There are various configurations of combined cycle plants. A single CT, coupled to a HRSG and steam turbine-generator set, is referred to as a "1 x 1" combined cycle plant. Similarly, 2 CTs, coupled with the HRSG and steam turbine-generator set is referred to as a "2 x 1" combined cycle plant. The Hawaiian Electric Companies own and operate several 2 x 1 combined cycle plants.

Combined-cycle plants typically exhibit the greatest efficiency technically possible with thermal generation. Heat rates for modern combined-cycle plants operating at a high capacity factor can be as low as 8,000 Btu/kWh. The reliability of combined-cycle plants is high. They tend to be utilized in base load and intermediate (that is, cycling) applications. This too is considered to be a mature technology, with incremental decreases to flat projected capital cost, and incremental performance improvements over time. Like CTs, combined-cycle power plants are utilized by utilities and IPPs around the world. There is a well established and mature supply chain. Financing is readily available in the capital markets for combined-cycle power plants that are owned by utilities or owned by IPPs with firm off-take contracts with a credit-worthy customer.

The PSIPs propose combined-cycle options for O‘ahu in a 152 MW 1 x 1 configuration and a 383 MW 3 x 1 configuration (the latter being proposed for a modernization program at the Kahe power plant).

Internal Combustion Engine (ICE). ICE generation couples an internal combustion engine with a generator. Modern ICE engine-generators are in widespread use throughout the world. They are the dominant technology employed in distributed generation applications; however, they are routinely found in utility-scale applications as well. The Companies are currently building a 6-unit x 8.4 MW (for a total of 50 MW) ICE generation station at the Schofield Barracks Army Base on O‘ahu. That project is scheduled to enter commercial operation in 2017. The Schofield Generating Station will provide additional operating flexibility to help manage increasing penetrations of variable renewable resources, including customer-owned solar PV. It is also being designed to allow Schofield Barracks to operate as a micro gird (that is, in an "islanded" mode) providing energy security for the base.

ICE generation has relatively high efficiencies (heat rates of approximately 10,000 Btu/kWh) across a wide operating range (25% to 100% of full load), and rapid start-up and shutdown capabilities. ICE generation is a mature technology. Cost and performance trends into the future are relatively flat. There is a robust and competitive market for ICE consisting of several major global vendors and a handful of other players.

Biomass. The Companies continue to explore opportunities for utilization of locally produced energy crops for their possible contribution to renewable power generation. Various parties in Hawai‘i continue to research and develop test crops' commercial potential including but not limited to cellulosic feedstock such as bana grass or energy cane and oil seed crops like jatropha, sunflower, and pongamia.

Crops for biofuel that could be used in thermal power generation as a substitute for or blend with fossil fuels include cellulosic crops or crop waste for biomass-to-gas-to liquid technologies that are not at commercial scale, and oil seed crops for feedstock for traditional biodiesel. A&B has expressed interest in pongamia trees that produce oil seed for biodiesel and can grow on less-than-optimal lands while serving as shade for other interspersed crops.

Biofuel is advantageous in its capability to substitute for liquid fuel in a number of existing generating units and is easily transported via truck containers and barges. Typically, both biogas and biomass for power generation are economically feasible only when the feedstock is in close proximity to the power generation facility. Cellulosic crops and crop waste can serve as feedstock for anaerobic digesters to produce biogas, which are commercially proven in installations around the world. The Companies' use of biogas for power would require conversion of existing generation to fire gas or new gas-fired generation. Biomass derived from energy crops, crop waste, or tree waste can be dried and pelletized to use in generating units that may otherwise burn coal. Cost-effective biomass or biogas generation using purpose-grown crops remains to be proven but holds promise.

The January 7, 2016 announcement by Alexander and Baldwin, Inc. (A&B) to cease production of sugar by Hawaiian Commercial Sugar and Company (HC&S) on Maui and transfer to a diversified agricultural model presents opportunities for further exploration of energy crops on portions of their 36,000 acres to determine if the economics and bioenergy technologies can be proven.

For purposes of the 2016 PSIP update, the capital costs for biomass plants was derived from the NREL ATB (with adjustment factors for Hawai'i), and an assumption that biomass fuel would cost $20/MMBtu.[46]

As of the date of the PSIP interim filing, the biomass assumptions are being re-examined. The basis for the variable costs (variable O&M and fuel costs) as reported in the assumptions sheets distributed to the parties on February 2, 2016 were found to incorrectly include certain capital costs, which result in a double-counting of a portion of the capital costs. Thus, the February 2 assumptions set for a biomass plant over-state the total cost. This is being corrected and the updated PSIPs will reflect analyses based on the revised assumptions.

Geothermal. Geothermal power generation relies on underground heat sources. Typically, water is injected into a well drilled into an underground pocket with high temperatures to create steam which is then channeled up to the earth's surface and used to turn a steam turbine-generator set to generate electricity. Hawai'i Electric Light currently purchases electrical capacity and energy from the Puna Geothermal Venture 38 MW geothermal power plant located on the island of Hawai'i. Geothermal is a proven technology and has been considered a new resource option for the 2016 updated PSIPs for Maui and Hawai'i Island. However, development of new geothermal generation in Hawai'i will require extensive resource development and permitting processes. For

[46] See: Anaergia Services, LLC, Maui Energy Park, LLC, and Maui Resource Recovery Facility, LLC's Opening Brief. Docket 2015-0324. At page 12, Anaergia states that their proposed fuel price is in the range of $18.75 / MMBtu to $22.31 / MMBtu.

Maui, and new Hawai‘i Island resource locations, additional field research (that is, test wells) is required to prove the geothermal resource potential. Accordingly, the 2016 updated PSIP will consider geothermal potential resources available in the later years of the PSIP analysis.

Other Generation Technologies

Offshore Wind. There are currently two proposed offshore wind projects being proposed for O‘ahu. The first consists of 400 MW on the NW side of the Island and the second is for 400 MW on the SSE side of the Island. Because of the significant water depths at the proposed Hawai‘i sites (±1000 meters), offshore wind installations in Hawai‘i will most likely employ large wind turbines installed on floating platforms and sited in deep water (± 1000 meters).

Floating wind turbine technology is less mature than fixed-bottom technology; the first floating turbine was installed in 2009 and four additional machines have been installed in subsequent years. Because these projects are single turbine, proof-of-concept installations, they have been more expensive than fixed-bottom projects (on a $/kW basis). These projects are not able to achieve economies of scale and have elevated budgets for research and development. Floating technologies are, however, becoming increasingly mature and the first commercial applications are expected to occur by 2020 (Smith et al. 2015).

The economics of floating technologies are different from fixed-bottom technologies. Some elements, such as electric infrastructure, will be more expensive because undersea power cables must be able to withstand dynamic loading within the water column, whereas power cables for fixed turbines can be laid out directly on the seabed. Further, in the Hawaiian Electric system, interconnection of a 400 MW offshore wind project and its effect on system security needs will need to be carefully evaluated. The design of this interconnection cable system will be extremely important since a failure of the cable system will severely impact system security since the loss of 400 MW of wind generation is considerably larger than the size of the current largest land based contingency.

There is the potential for capital costs to be lower than fixed platform structure because the entire turbine-substructure unit can be assembled in port and towed to the project site. However, in Hawai‘i these cost reductions will be possible only if appropriate facilities (for example, ship-building type facilities) and heavy construction equipment are available. Because the weight of floating platforms is relatively insensitive to turbine size, the economics generally are substantially improved for projects that use large (for example, 8+ MW) wind turbines.

In summary, there is considerable uncertainty about the future cost of floating technology given its pre-commercial status and the intention for it to be deployed in the Hawai‘i environment. A preliminary analysis conducted by NREL and the U.S. Department of Energy suggests that a reference floating offshore wind facility installed in 2020 could have an Installed Capital Cost of approximately $4,500 per kW. However, data supplied by NREL also shows that $4,500 per KW is the lowest price ever achieved at least for the data sets of offshore wind projects included in the NREL analysis (see Figure D-3).[47] Development risk factors could affect the cost of offshore wind projects in Hawai‘i. Notwithstanding these uncertainties, we have used the NREL figure of $4,500 per KW in our assumptions set, but we caution that there is considerable uncertainty in this figure.

Heeding the Commission’s direction to avoid utilizing “unproven resources with uncertain feasibility” as the centerpiece of a renewable strategy for our systems, at this time, we do not consider floating platform offshore wind in very deep water a technology that should be included as a priority resource for consideration in the 2016 updated PSIP plans. However, the Commission has asked the Company to re-evaluate the feasibility of an inter-island cable (a commercially available and relatively mature technology) in the 2016 PSIP update. Because offshore wind and inter-island cables both offer potentially competing solutions for helping O‘ahu reach 100% RPS, we will evaluate offshore wind in our cable evaluations, to be completed subsequent to this filing, and included in the April 1, 2016 updated PSIPs. As noted multiple times in the 2014 PSIPs, and as noted herein, we will seriously consider specific project proposals that meet our system needs and that meet a number of technical, commercial, and financial criteria.

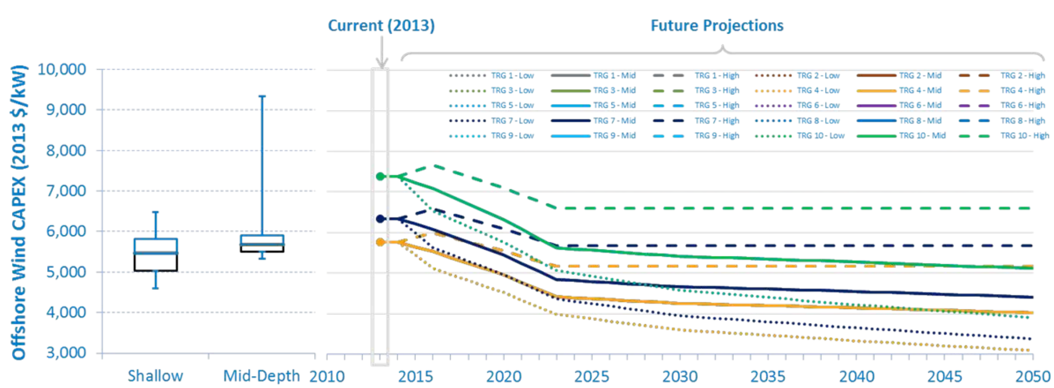

Figure D-75. Offshore Wind Capital Costs – Actual and Projected (Source: NREL)

[47] http://www.nrel.gov/docs/fy15osti/64077.pdf at 38.

Concentrated Solar Power (CSP). CSP is a rapidly advancing technology on the cusp of becoming commercially available. However, the installed base of global CSP capacity is still only approximately 1,200 MW.[48]

Concentrated solar power utilizes thermal radiation from the sun. The thermal solar energy is typically transferred to a working fluid and the heat is in turn used to make steam. That steam is used in a steam turbine coupled to an electric generator. In some CSP applications, the thermal energy can be stored, spreading the output of the CSP facility over a longer number of hours per day, resulting in higher capacity factors than can be achieved with solar PV technology. CSP requires direct sunlight to function efficiently; cloud cover significantly degrades performance (in contrast to solar PV which does not exhibit as much performance degradation on cloudy days relative to CSP). As a result, most of the operating CSP plants are located in deserts in places such as California, Spain, and the Middle East.

CSP is has a relatively expensive capital cost. With the maturity of solar PV and the rapidly improving performance and steep forecasted capital cost price declines of battery energy storage systems (BESS), the technical and economic viability of CSP relative to a solar plus BESS applications may be relatively limited to areas with consistent solar thermal radiation.

Solar PV + Storage Combination (aka Nighttime Solar). While not a separate resource technology, it is worth mentioning that a combination of utility-scale solar PV and BESS systems can create a "dispatchable" renewable resource. Particularly with the performance and cost improvements of BESS technologies, this combination of technologies may be a useful tool for achieving RPS goals. Kauai Island Utility Cooperative (KIUC) has recently announced its intent to develop a project with 17 MW of solar PV combined with a 13 MW/ 52 MWh (4 hour duration) BESS system.[49] The promise of this project is that will allow KIUC to store solar energy during the distributed-solar PV driven "valley" of the daily demand curve, and then provide that energy later in the day and evening to serve the daily peak demand. The Companies anticipate that future solicitations for new resources may result in proposals for this combination of technologies.

Waste-to-Energy. Like biomass plants, waste-to-energy (WTE) systems are dominated by two basic technologies: systems that involve direct combustion of the waste, with the resulting heat being used in a boiler to make steam that then drives a steam turbine-generator set, and gasification systems in which the waste is broken down into a low-BTU gas that is then typically used to fuel an ICE generator.

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48 http://www.energy.gov/articles/year-concentrating-solar-power-five-new-plants-power-america-clean-energy.

49 http://cleantechnica.com/2015/09/22/now-solar-power-meet-evening-peak-load-hawaii/.

WTE facilities tend to be very site specific in terms of design, because of the need to size the plant for the volume of the waste stream, and the need to utilize technology that is appropriate for the makeup of the waste stream. For this reason, reliable capital cost and operating data for WTE plants has been difficult to find. None of the data sources identified above cover or routinely provide analysis for a "typical" WTE plant.

The relatively smaller sizes (given the volume of waste streams) of WTE plants that would be deployed on Maui, Lana'i, Moloka'i, and Hawai'i Island also make reliable cost data difficult to come by; a literature search of smaller WTE plants reveals potential capital costs for WTE plants ranging from around $4,000 per KW to $11,000 per kilowatt. WTE plants exhibit economies of scale meaning that very small plants will likely have a high per unit capital cost compared to larger WTE plants. From the WTE owner's perspective, the economics of a WTE plant are not only a function of the sales of electricity, but are also a function of the "tipping fees" received from the source of the waste, and in some cases, from the value of recycled materials pulled from the waste stream before it enters the WTE plant itself. Thus, even with a given capital cost, there is the potential for a great deal of variability in determining a projected price for electricity from a WTE plant.

From an operational perspective, the typical WTE system is not able to substantially vary its output, because of the relative narrow efficient operating range (especially direct combustion WTE plants) and the requirement to continuously process the constant flow of waste.

The Hawaiian Electric system takes power from HPOWER, a 68.5 MW waste-to-energy facility located in the Campbell Industrial Park and owned by the City and County of Honolulu. HPOWER process up to 3,000 tons per day of municipal solid waste.[50] HPOWER is a steam plant.

In recent years, several proposals have been floated by the County of Hawai'i and the County of Maui for waste-to-energy plants. The last two mayoral administrations in the County of Hawai'i both proposed waste-to-energy facilities, but both plans were abandoned. Several private developers have also proposed WTE facilities on Hawai'i Island. In the County of Hawai'i, there have been some questions regarding whether the waste stream is adequate for supporting a WTE plant.[51] There is a pending proposal from the County of Maui and a private developer to provide gas derived from municipal waste landfills to fuel existing Maui Electric power plants. The Companies will continue to work with the communities on WTE proposals that can help with municipal solid waste disposal issues, and provide benefits to electricity customers.

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[50] http://www.covanta.com/facilities/facility-by-location/honolulu.aspx.

[51] http://bigislandnow.com/2014/04/22/big-island-rubbish-enough-to-go-around/.

Ocean Thermal Energy Conversion (OTEC). Hawai‘i is a pioneer in OTEC research, having demonstrated the first successful OTEC project on Hawai‘i Island in the 1970s. Despite the technological promise of OTEC for large-scale electricity generation, no full-scale OTEC plant has yet to be built anywhere in the world. Since the conclusion of the 2014 PSIP process, OTEC International (OTECI), which had proposed a 100 MW OTEC project to serve O‘ahu, announced that it was withdrawing from the Hawai‘i market.[52] Should this technology become mature to the point that it is commercially viable and demonstrates the ability to be financed without substantial subsidies, future power supply plans may include OTEC as a resource option.

Wave and Tidal Power. Successful demonstration tidal and wave power projects have been implemented in several locations, including Hawai‘i. We currently partner with the U.S. Navy (and others) in a small scale pilot. Small utility-scale wave power projects have been installed in Europe. Implementing large-scale tidal and wave installations has thus far been hampered by a lack of understanding of the associated siting and permitting challenges in multiple jurisdictions. Wave and tidal power projects may face similar interconnection challenges to offshore wind (as described above).

Should this technology become mature to the point that it is commercially viable and demonstrates the ability to be financed without substantial subsidies, future power supply plans may include wave and tidal power as a resource option.

Figure D-76. Pelamix Wave Energy Converter at the European Marine Energy Test Centre (EMEC) 2008

[52] http://www.utilitydive.com/news/heco-developer-shelve-100-mw-ocean-thermal-energy-project-off-hawaii/401000/.

Microgrids. The U.S. Department of Energy defines a microgrid as:

> " … a group of interconnected loads and distributed energy resources (DER) with clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid (and can) connect and disconnect from the grid to enable it to operate in both grid connected or island mode."[53]

A typical microgrid consists of distributed generation (for example, internal combustion engines, combined heat and power systems, solar PV, distributed wind), energy storage systems, and demand management systems that in effect create a balancing area within a defined set of loads. As indicated in the DOE microgrid definition, microgrids can operate interconnected with the larger utility system, or they can operate in an islanded mode. Islanded operation is particularly of interest to customers who require a very high level of reliability and energy security. The Schofield Generating Station, which is under construction, is designed to allow islanded operation of the Schofield Barracks Army Base (that is, the system functions as an islanded microgrid).

Microgrids require control systems that balance load with generation on a real time basis. In combination with utility time-based rate programs (such as time-of-use rates, dynamic pricing, and critical peak pricing) and demand-response programs, sophisticated microgrid control systems allow microgrids to "call" power from the grid when it is economically advantageous to do so, and "put" power to the grid in response to DR program price signals.

The Company believes that microgrids can play a useful role in providing additional flexibility to the grid. Customer with critical loads who can justify the costs of providing higher reliability are likely to play a role in providing services to the grid. Proposals for microgrids that aggregate multiple customer loads, raise numerous issues (such as cost allocation, rate design, and stranded costs) issues that are beyond the scope of the 2016 PSIP update. The Company will evaluate proposals for microgrids on a case by case basis.

Constraints on New Utility-Scale Resources

In Order No. 33320, the Commission expressed concern that the constraints on resources by island were "unsubstantiated."[54] We acknowledge that an accurate and realistic estimate of the incremental resource potential, particularly on O‘ahu, is very important in light of Hawai‘i Act 97 providing for the 100% RPS. To the extent that there are significant constraints on O‘ahu, the strategic need for off-island options (for example, offshore wind and inter-island cables) becomes greater.

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[53] https://building-microgrid.lbl.gov/microgrid-definitions.

[54] Order No. 33320, Concern 2.c. at 84.

In order to address this important question, the Companies retained NREL to perform an analysis of the "developable" potential on O'ahu, Maui and Hawai'i Island. The NREL analysis is utilizing 4 km resolution solar insolation and wind resource potential maps for each island that have been developed by NREL. "Exclusion" factors (that is, types of areas where development of wind or solar cannot be constructed) are then applied. These exclusion factors include:

- Topography (for example, mountains, lakes) not conducive to development
- Heavily populated areas
- Park lands and wet lands
- Designated "Important Agricultural Land"
- Proximity to existing transmission facilities

The results of the NREL analysis, received on Friday, February 12, 2016, expand on this.

Table 4-7 shows the preliminary results of the NREL analysis regarding the potential for new wind and solar resource potential by island—the total resource potential including existing resources. These results indicate that while the neighbor islands have substantial "developable" resource potential, O'ahu is reaching its limits with respect to additional wind resources. With respect to utility-scale solar PV potential on O'ahu, there is still adequate resource potential, if it is possible to develop solar PV on lands with slopes greater than 3%. If a slope of more than 3% is a limitation on the development of utility-scale solar PV on O'ahu, then the remaining solar PV potential on O'ahu is zero.

Preliminary Results of NREL's Island Resource Potential Study				
Resource	*Exclusion Criteria*	*O'ahu*	*Hawai'i*	*Maui*
Utility-Scale PV	Excludes capacity factor potential less than 20%, Excludes all areas with slope greater than 5%	2,007 MW	45,951 MW	1,666 MW
Utility-Scale PV	Excludes capacity factor potential less than 20%, Excludes all areas with slope greater than 3%	0 MW	3,704 MW	0 MW
Utility-Scale Wind	Excludes all areas with wind speeds less than 6.5 meters / second at 80 meters high	174 MW	3,276 MW	698 MW

Table D-92. Preliminary Results of NREL's Island Resource Potential Study

Utility-Scale Resource Options by Island Available for the 2016 PSIP Analysis

Table D-4 summarizes the PSIP utility-scale resource options that are available to the planning teams for development of long-term power resource plans. These assumptions are preliminary and could change based on further analysis.

Resource Type	PSIP Assumed Project Block Sizes by Technology			
	O'ahu	Maui	Moloka'i and Lana'i	Hawai'i Island
Solar PV	20 MW	1 MW, 5 MW, 10 MW, 20 MW	1 MW	1 MW, 5 MW, 10 MW, 20 MW
Onshore Wind	30 MW	10 MW, 20 MW, 30 MW	Research Pending	10 MW, 20 MW, 30 MW
Combustion Turbines	100 MW	20.5 MW	n/a*	20.5 MW
Combined-Cycle	152 MW 1 x 1, 383 MW 3 x 1	n/a	n/a	n/a
Internal Combustion Engines	27 MW (3 x 9 MW), 54 MW (6 x 9 MW), 100 MW (6 x 16.8 MW)	9 MW	1 MW	9 MW
Geothermal	n/a	20 MW†	n/a	20 MW
Biomass	20 MW	20 MW	1 MW	20 MW
Resource Technologies For Possible Evaluation in Sensitivities				
Waste-to-Energy	n/a	10 MW	1 MW	10 MW
Offshore Wind	400 MW	n/a	n/a	n/a
Off-Island Wind + Cable	200 MW, 400 MW	n/a	n/a	n/a
Solar CSP w/10 hours storage	100 MW	n/a	n/a	n/a

* A small CT was not considered for Moloka'i and Lana'i as their efficiencies are far less than those of an ICE unit of the same size.

† The geothermal option availability for Maui is limited to post 2030 in the 2016 PSIP update analysis.

Table D-93. Preliminary New Utility-Scale Resource Options Available in the 2016 PSIP Analyses

Comments on Table D-93:

- At the time of this filing, we are researching viable small wind technologies which might cost effectively compete with other technologies. The deployment of a single larger turbine of the type included for the other systems would be prohibitively expensive to install and maintain because of the mobilization and special equipment required. This cost would typically be spread over a wind installation with many turbines. In the case of Moloka'i and Lana'i this cost would have to be spread over a single turbine.
- The ability to properly evaluate waste-to-energy facilities in the 2016 PSIP update is contingent upon the ability to acquire reliable data regarding Hawai'i-specific cost and performance characteristics of a WTE plant at or close the sizes shown above. The Companies welcome input from the parties in the development of the assumptions for WTE.

Risks and Uncertainties Associated with Resource Acquisition

The Commission has asked the Companies to address the risks and uncertainties associated with acquiring new resources.[55] In general, the development of utility-scale energy infrastructure, whether by the utility, an independent power producer, or otherwise, involves the management of a number of risk factors. These risk factors, if not managed well, can have an adverse impact on the ability of the State to achieve the 100% RPS goal.

[55] Order No. 33320 at 41.

Technology Risk. The technology must be commercially proven, particularly if the project utilizing the technology is expected to provide a significant portion of the power to the system it is serving. Commercially proven technologies are characterized by a well capitalized and experienced vendor who can offer a performance warranty on the technology. Large projects also require an experienced and well capitalized construction firm who will provide and stand behind contractual assurances that the project will be completed within the budget and a specific schedule, and importantly, guarantee the performance of the overall project. The technology must be backed by a supply chain of parts and services necessary to operate the plant. In other words, the technology must meet the criteria mentioned by the Commission in Order 33320; it must *not* be "unproven" and must *not* have "uncertain feasibility." As identified above, solar PV, onshore wind, internal combustion engines, combustion turbines, combined-cycle, geothermal and biomass technologies generally meet these commercial requirements. It is incumbent upon the developer of projects using the technologies to utilize vendors.

Permitting and Siting Risk. Depending on the project type and location, a typical project might involve consultation with dozens of state and federal agencies, preparation and dissemination of notices, preparation of numerous impact reports and studies, and navigation through a maze of state and federal agency permitting processes. Many of the permits are subject to contested hearing processes and all permits are subject to appeals by those who oppose a particular project. This complexity in permitting requires extremely well qualified parties with experience developing new infrastructure, and parties who understand the unique social and cultural dynamic of Hawai‘i. Hawai‘i’s recent history with large infrastructure projects has been one characterized by community opposition and legal challenges.

In some cases, permits that have been issued have been revoked because of procedural errors on the part of permitting agencies, after the developers have spent significant time, effort and money working in good faith with the communities and permitting agencies to obtain those permits.[56] This atmosphere of uncertainty leads to less competition for new projects from highly qualified parties (with resulting higher costs for the projects and greater risk on non-completion) and a higher cost of capital for projects that can be done. This is a significant risk for achievement of Hawai‘i’s 100% RPS goals, because under any case for achieving 100% RPS, significant new infrastructure is needed, requiring significant amounts of capital to be raised in capital markets, and requiring highly qualified developers with experience in completing complex projects within schedule and budget constraints.

[56] "Hawaii Supreme Court Revokes Construction Permit For Thirty Meter Telescope On Mauna Kea." *Forbes*. December 3, 2015. http://www.forbes.com/sites/alexknapp/2015/12/03/hawaii-supreme-court-revokes-construction-permit-for-thirty-meter-telescope-on-mauna-kea/#550cc2223094.

Construction Risk. Construction risk is typically managed by the project developer, but such risks can be significant. Unforeseen site conditions, discovery of endangered species and or previously unknown archeological finds, labor strikes and lockouts, and material and labor shortages are all factors that can affect the cost and schedule of construction. Extended delays in construction can result in cost uncertainty as commodity prices and interest rates fluctuate. These risks are manageable, but again, large infrastructure construction risks require sophisticated construction project management skills and experience.

Financing Risk. Large infrastructure projects require significant amounts of capital. The incremental capital to develop these projects must be raised in capital markets. Most projects utilize a combination of equity and debt. The willingness of both debt and equity providers to supply the capital to build new infrastructure projects, and the price of the capital (that is, equity returns required and debt interest rates) depends on a number of factors. First, capital providers look at the merits of the project itself. Second, they look at the regulatory and political risks associated with the project and the relative certainty of the regulatory and political environment and whether that environment is conducive to a return of, and a return on the capital provided. Third they look at the financial strength of the off taker of the project output (in the case of major energy infrastructure, this is the local utility company). And finally, they look at the ability of the project developer to manage the risks identified above. To the extent that these risks are present in the environment in which the project is to be constructed, fewer capital providers will be available to compete for providing this capital, and the result will be a higher cost of capital, which is in turn borne by customers.

UTILITY-SCALE ENERGY STORAGE RESOURCE ASSUMPTIONS

Energy Storage Applications

The 2014 PSIPs included "Appendix J: Energy Storage for Grid Applications" which discussed energy storage technologies in detail, including the various technologies and applications. The information presented in that the 2014 PSIP Appendix J remains relevant, so we refer the reader there for a detailed background discussion of the basics of energy storage and emerging technology types.

In the 2016 updated PSIPs, we developed detailed assumptions around several applications, using several technologies. The applications, uses, duty cycles, technologies and sizes of energy storage systems are summarized in Table D-5.

Application	Description of Use	Duration	Storage Duty Cycles	Depth of Discharge	PSIP Technologies	Sizes Available to Planners
Inertia	Provide ride-through of momentary system disruptions; avoid system contingency	Seconds	5,000 per year	Deep (up to100%)	Flywheels	Flywheel 10 MW
Contingency	Instantaneously (< 7 cycles) serve load when a system contingency (generation trip or sudden transmission fault) occurs; frequency response	Up to 30 minutes	≈ 10 per year	Deep (up to100%)	Lithium Ion BESS	BESS: 1, 5, 10, 20, 50, 100 MW
Regulation	Smooth fluctuations in system load; smooth fluctuations in output of variable renewables; frequency response	Up to 30 minutes	≈ 15,000 per year	Shallow (20% to 50%)	Lithium Ion Battery Energy Storage Systems (BESS). Pumped Storage Hydroelectric (PSH)	BESS: 1, 5, 10, 20, 50, 100 MW PSH: 30, 50 MW
Load Shifting	Store excess variable renewable generation for use at a later time; circuit level support to accommodate DER; non-transmission alternative	1 – 8 Hours	Daily	Deep (up to100%)	Lithium Ion BESS PSH Hydrogen Energy Storage CSP with Storage	BESS: 1, 5, 10, 20, 50, 100 MW BESS: 2 MW for grid support PSH: 30, 50 MW Hydrogen: not commercial CSP: 100 MW

Table D-94. 2016 Updated PSIP Energy Storage Applications, Sizes, Technologies

In practice, a single energy storage installation can be used for other than its primary purpose. A load shifting battery can also provide regulation service if required. A contingency battery could in theory provide some load shifting. For example, a 20 MW, 30-minute hour battery (that is, 10 MWh) could provide 10 hours of load shifting storage if the output of the battery system is limited to 1 MW (1 MW * 10 hours = 10 MWh). For batteries, the key is to closely manage the charge and discharge cycling of the battery in order to as to maintain its useful life based on the application for which it was designed.

As noted in Table D-5, pumped storage hydroelectric can provide services other than load shifting, although it is unlikely that pumped storage would be built solely to meet applications other than load shifting.

Cost Assumptions Related to Energy Storage

The specific capital cost assumptions for energy storage resources are presented in Appendix A. Figure D-5 depicts the underlying constant 2016 $ assumptions for the capital costs associated with selected sizes, technologies and applications for energy storage systems assumed in the 2016 updated PSIP.

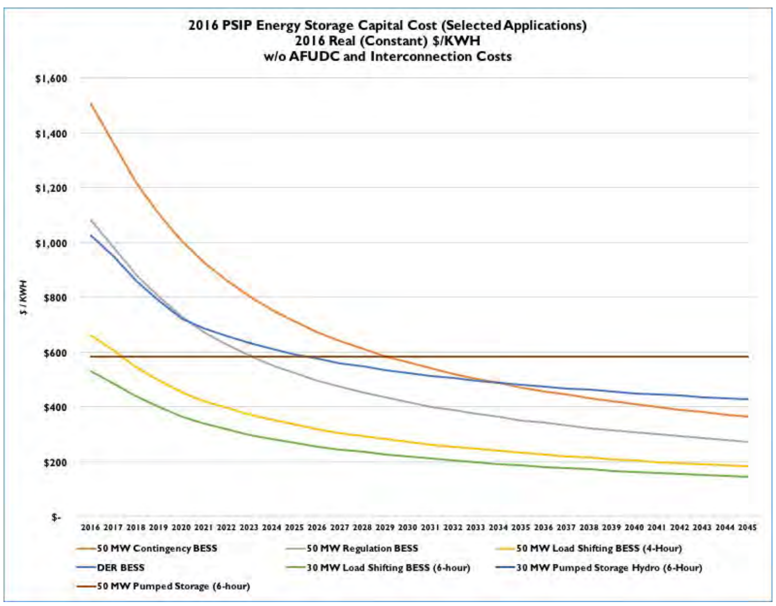

Figure D-77. 2016 PSIP Energy Storage Capital Costs –Selected Applications

The methodology for determining the capital and operating costs assumptions for energy storage systems was largely the same as described above for new utility-scale generating facilities. The primary source of data for current prices and forward curves was IHS Energy consultants. Prices were adjusted for Hawai'i using RSMeans city indices. Prices were adjusted upwards by 4% to account for Hawai'i general excise taxes.

Adjustments to BESS prices and costs were made based on the different applications described above. The application affects the "duty cycle" of the BESS, which in turn drives certain design parameters including the spacing of cells for the dissipation of heat (longer duration storages requires more spacing, resulting in larger footprints) and air conditioning requirements. From an O&M perspective, more frequent and deeper discharge of BESS requires replacement of battery cells more often in order to maintain output.[57]

Commercial Status of Energy Storage Technologies

Various sizes of energy storage systems are commercially available ranging from 1–2 kilowatts of output to hundreds of megawatts, and in output durations of as much as six hours or longer.

For the 2016 PSIPs we considered three specific types of energy storage technologies: lithium-ion battery energy storage systems (BESS), flywheel energy storage systems, and pumped storage hydroelectric (PSH). We also include discussions of solar CSP

Lithium Ion BESS. Lithium-ion energy storage technologies have rapidly advanced to the point that they are commercially available for utility-scale and distributed energy applications. These advances have been led by the development of advanced lithium-ion batteries for use in consumer electronics and automotive applications. According to a recent report from the Electric Power Research Institute (EPRI), batter energy storage "…is emerging as a potential technology solution for the utility industry because of a confluence of industry drivers related to both energy storage technology advancement as well as transformations in the electric power enterprise."[58]

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[57] Some vendors oversize the battery form the start, so that as the batteries degrade over time, the project's output declines to the customer's specified output requirements. Others provide warranty wraps where they replace cells as they degrade so that the desire output is maintained.

[58] Electric Power Research Institute Inc. *Energy Storage Valuation Analysis: 2015: Objectives, Methodologies, Summary Results, and Research Directions*, Technical Update 3002006068, January 2016.

The EPRI report identifies several trends within the energy storage industry:

- Technological advances in energy storage with active cycling capabilities, combined with longer useful asset lives.
- Declining costs and performance improvements in lithium-ion battery technologies.
- A pipeline of innovative research and development related to more advanced storage technologies, which could lead to lower costs and longer durations of energy storage.

Even with their current commercial status, the expectations are for lithium ion battery performance to improve, and for costs to continue to drop. Utility-scale lithium ion batteries installations can easily be scaled in size, have relatively short lead times for procurement and installation, and have ultimate flexibility in terms of locating them where there is available real estate and/or existing utility plant sites. Lithium ion BESS can be configured for a number of different applications at various voltage levels, have relatively short lead times for engineering and installation, and have significant flexibility in terms of siting and permitting because they can be installed in a variety of settings (for example, power plant sites, substations). This flexibility makes lithium ion BESS an excellent candidate for providing non-transmission alternatives in constrained areas. The typical efficiency of lithium-ion batteries is 80%–90%, depending on the application.

Disposal of lithium ion batteries presents a challenge to the energy storage industry. The use of lithium ion batteries is largely being driven today by automotive and consumer electronic applications. A great deal of effort is being put into developing proper disposal and recycling methods for lithium ion batteries.[59]

In Docket their comments filed on January 15, 2016 in Docket 2014-0183, Paniolo Power states: "…while larger battery systems are starting to be built, batteries used for long duration, utility-scale applications must still be considered in the development phase… Battery technologies for long duration storage should be considered still under development as they are simultaneously attempting to improve the chemical compositions, storage capacity, operating life, disposal issues, and costs of batteries."[60]
Respectfully, we do not agree with Paniolo Power's characterization of long duration BESS storage. Lithium-ion battery technology has made substantial advances in cost and performance. Several vendors have reached a level of maturity and capitalization that they can offer performance guarantees on utility-scale lithium-ion battery systems. As previously noted, KIUC has contracted with a developer to purchase power from a solar PV project that incorporates a 4-hour lithium ion BESS system. We believe this is indicative of their lithium-ion BESS maturity as long duration energy storage option.

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[59] See for example: http://energy.gov/sites/prod/files/2015/06/f23/es229_gaines_2015_o.pdf.

[60] Docket 2014-0183, Comments of Paniolo Power, January 15, 2016, pp 23–24.

Flywheel Storage Devices

Flywheel storage devices will be evaluated against battery storage systems for total cost; that evaluation will be included in our Updated PSIPs.

A flywheel is a rotating mechanical device consisting of a rotor attached to a motor and generator that spins at high speeds, used to store and discharge rotational energy. When absorbing energy, the flywheel's motor acts like a load and draws power from the grid to accelerate the rotor to higher speed. When discharging, the motor switches into generator mode; the inertial energy of the rotor drives the generator, creating electricity that is injected back into the grid as the rotor slows down. The flywheel has both a minimum and maximum design speed. The actual speed of the flywheel is an indication of the "state of charge" of the system, with the minimum speed representing a fully discharged flywheel and the maximum speed representing a fully charged state.

The mechanical inertia of a flywheel system makes is ideal for serving as a contingency resource in an island power system, where a contingency event can result in significant frequency decay in a highly compressed timeframe. In an island power system, the frequency decay can occur in a faster timeframe than online spinning generators can respond. Contingency reserves are the specific application for flywheels, which make them a candidate for inclusion as a PSIP storage resource option.

Flywheel energy storage technologies have been commercially available for at least 10 years, primarily serving niche applications such providing ride-through capabilities during transfer of power from primary power sources to backup power sources (for example, emergency standby generator applications) in facilities requiring high levels of reliability (for example, data centers). At the present time there are more than 400 flywheels in utility-scale commercial operation. Flywheel operating hours exceed 7 million.[61]

Beacon Power is currently the only flywheel manufacturer that provides commercial utility-scale systems operating in the U.S. market. Other flywheel manufacturers (such as Amber Kinetics) are working towards bringing their systems to market.

The rotor of a Beacon Power flywheel system spins between 8,000 rpm and 16,000 rpm. At 16,000 rpm, a single Smart Energy 25 flywheel can deliver 30 kWh of extractable energy at a power level up to 265 kW for 5 minutes or as low as 170 kW for 10 minutes (See Figure D-6).

[61] http://beaconpower.com/operating-plants/.

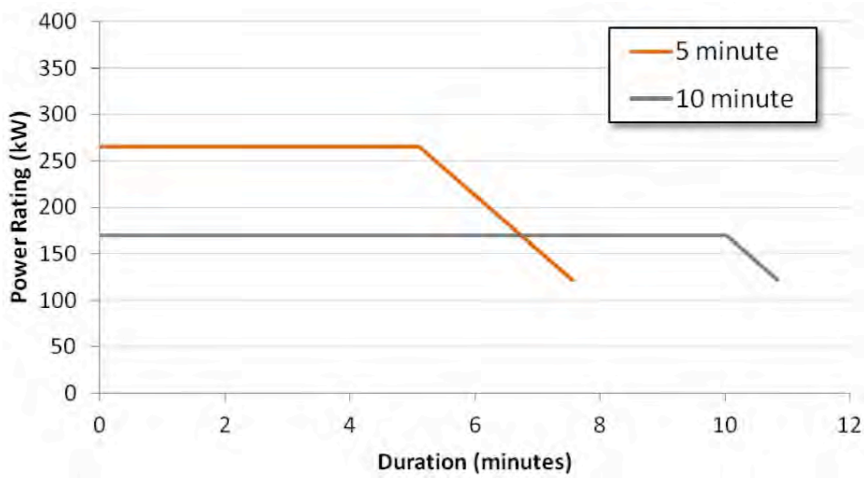

Figure D-78. Flywheel Extractable Energy Rates and Duration

The cyclic life capability of energy storage-based systems is of critical importance for performing frequency regulation. Beacon's flywheel is designed for a minimum 20-year life, with virtually no maintenance required for the mechanical portion of the flywheel system over its lifetime.

Beacon's experience to date in ISO New England involves 6,000 or more effective full charge and discharge cycles per year. The flywheel system is capable of over 175,000 full charge and discharge cycles at a constant full power charge and discharge rate, with zero degradation in energy storage capacity over time. For frequency regulation applications, flywheel mechanical efficiency is over 97 percent, and total system round-trip charge and discharge efficiency is 85 percent. Figure D-7 compares a flywheel's cycle life to that of a lithium-ion battery, showing a flywheel's superior capacity.

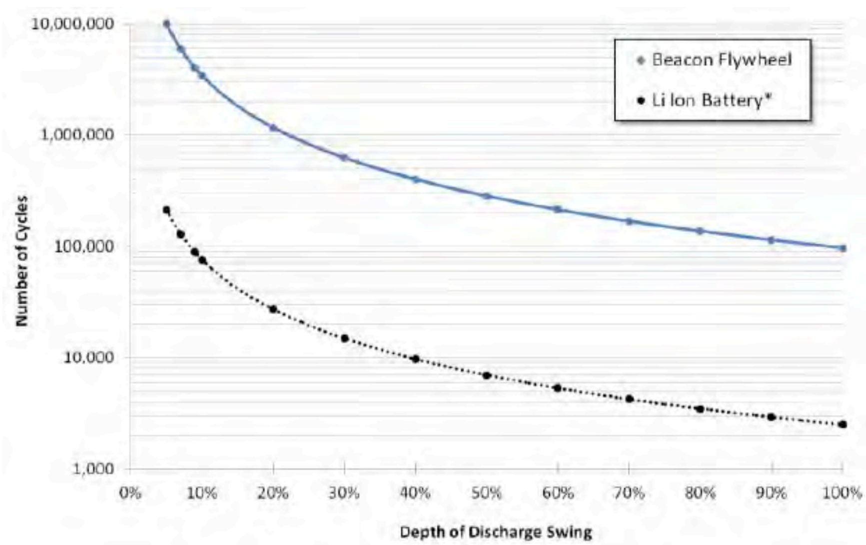

Figure D-79. Flywheel Cycle Life versus Lithium-Ion Battery

Pumped Storage Hydroelectric (PSH). PSH will be evaluated against battery storage systems for total cost; that evaluation will be included in our updated PSIPs.

Pumped storage hydroelectric energy storage is a mature and proven technology accounting for 99% of the energy storage capacity currently online. Pumped-storage hydroelectricity (PSH) stores energy in the form of gravitational potential energy of water, pumped from a lower elevation reservoir to a higher elevation. At times of low electrical demand or when there is excess renewable energy production, electricity is used to pump water into the higher reservoir. Later, to supply this energy back into the system, water is released back into the lower reservoir through a turbine, generating electricity. Reversible turbine/generator assemblies act as pump and turbine. Sufficient height difference between two natural bodies of water or artificial reservoirs is needed to make the system work. The typical design round-trip efficiency of PSH is 79-80%. Figure D-8 shows the typical layout of a PSH project.

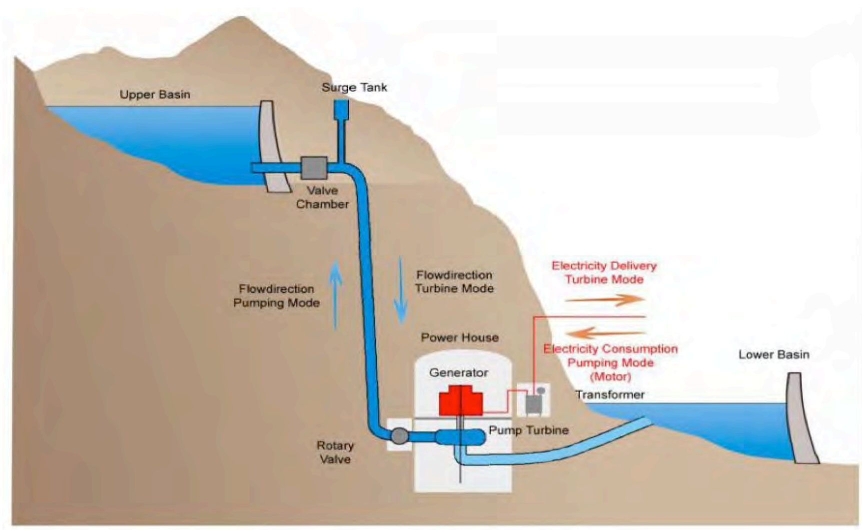

Figure D-80. Typical Pumped Storage Plant Arrangement[62]

[62] Source: Alstom Power.

Pumped storage is the most widely used form of storage for large electrical grids. There is more than 120,000 MW of PSH installed around the world.[63] One list of PSH projects reveals that the preponderance PSH projects in the world are very large, exceeding in many cases 1000 MW per installation.[64]

PSH is very site specific, relatively expensive, and has long lead times for permitting and construction. According to the U.S. Department of Energy:

> Pumped storage is a long-proven storage technology, however, the facilities are very expensive to build, may have controversial environmental impacts, have extensive permitting procedures, and require sites with specific topologic and/or geologic characteristics. As estimated in a report commissioned by EIA, the overnight cost to construct a pumped hydroelectric plant is about $5,600/kW…[65]

Especially in Hawai'i PSH sites may potentially be located in areas of outstanding natural beauty, areas of archeological or cultural significance, and/or areas that are environmentally sensitive.

Over the years, there have been a number of PSH projects proposed and studied in Hawai'i. As shown in Table D-95, the results of these studies shows a wide distribution of the per unit capital cost data, reflecting the site specific nature of PSH (and in the case of many of the projects in the table, old assumptions that must be re-verified).

[63] "Packing Some Power," The *Economist.* May 3, 2012, http://www.economist.com/node/21548495?frsc=dg%7Ca (citing EPRI as their source).

[64] https://en.wikipedia.org/wiki/List_of_pumped-storage_hydroelectric_power_stations. (This list is not complete. We are aware of projects not included in this list, and some smaller than the ones listed by this source).

[65] http://www.eia.gov/todayinenergy/detail.cfm?id=6910.

Table D-95 summarizes some of the projects studied.

Island	Study Year	Site Designation	Size (MW)	Hours of Storage	Estimated Capital Cost (Nominal $)	Estimated Capital Cost per KW (Nominal $)
O'ahu	No data	Kapaa Quarry	No data	No data	No data	No data
	No data	Ku Tree Reservoir	No data	No data	No data	No data
	No data	Nuuanu Reservoir	No data	No data	No data	No data
	1994	Koko Crater	160	7.5	$161 million	$1,006
	1994	Kaau Crater	250	8.0	$256 million	$1,024
	2004	Kunia	150	8.0	$189 million	$1,260
	2007	Mokuleia	50	12.0	$197 million	$3,940
	2008	Hawaiian Cement	7 - 74	8.0	No data	No data
	2014	Palehua	200	6.0	$650 million	$3,250
Hawai'i	1995	Puu Waawaa	30	6.0	$71 million	$2.367
	1995	Puu Anahulu	30	6.0	$71 million	$2,367
	1995	Puu Enuhe	30	6.0	$61 million	$2,033
	2004	Hawi	10	5.0	$39 million	$3,900
	2004	Waimea	2.3	12.0	$17 million	$7,391
	2006	Kaupulehu / Kukio	50	5.0	$239 million	$4,780
	2016	Mauna Kea 15a	56.4	5.0	$228 million	$4,046
	2016	Mauna Kea 5	22.9	5.0	$105 million	$4,583
	2016	Mauna Kea 15a + 8c	97.0	5.0	$422 million	$4,352
	2016	Kohala 12	18.1	5.0	$89 million	$5,426
	2016	Kohala 8	39.6	5.0	$239 million	$6,036
Maui	1995	Maalaea	30	6.0	$83 million	$2,767
	1995	Honokowai	30	6.0	$77 million	$2,567
	1995	Kahoma	30	6.0	$104 million	$3,467
	2006	Puu Makua	50	12.0	$169 million	$3,380
	2007	Lahina West (PMC)	14.7	5.0	$62 million	$4,218
	2007	Lahina West (KDC)	6.9	3.6	$39 million	$5,652
	2007	Makawao	31.2	5.0	$220 million	$7,051
	2008	Kihei	50	9.0	$315 million	$6,300
Moloka'i	2007	East Molokai # 1	3	5.0	$15 million	$5,000
	2007	East Molokai # 2	1	5.0	$7 million	$7,000
	2007	West Molokai	8.6	5.0	$57 million	$6.628

Table D-95 Historical Studies of Pumped Storage Hydroelectric Projects In Hawai'i

In developing our capital cost assumptions for PSH, we could find only a few instances where comparable size PSH plants (that is, those significantly less than 100 MW) have actually been constructed. The several smaller project data points we found were for proposed, not constructed, PSH projects.

Notwithstanding the lack of capital cost data for projects in the size ranges proposed for Hawai‘i, we acknowledge the proposals and views by others in Hawai‘i that PSH needs to be evaluated. Based on very limited data, we are using a capital cost estimate or PSH projects in the 30–50 MW size range of $3,500 per KW in 2016 $. We believe this is optimistic as there are many unknowns associated with the development of a utility-scale PSH project in Hawai‘i. The forecasted trend for PSH capital cost is flat in real terms, reflecting a mature technology.[66] This estimate is considerably below the EIA estimate cited above. We therefore caution that this figure has a great deal of uncertainty in it, relative to our estimates of other storage technology and generation capital cost assumptions.

We also believe that PSH projects would face substantial permitting challenges in Hawai‘i. The need for development of reservoirs where none current exist is in particular a major risk factor in light of archeological and cultural concerns that must be addressed in Hawai‘i. The lengthy permitting and construction lead times for PSH introduces additional risk since the commitments for PSH investments must be made far in advance of their commercial operation dates. However, a substantial benefit of PSH, once it is installed, is that it has a useful life of 50 years or more.

We will evaluate PSH in the 2016 updated PSIPs against other storage technologies. However, at this time, as previously mentioned, we believe that lithium-ion battery storage is the reference technology that we should be using for energy storage assumptions in the 2016 PSIPs. If developers present the Company with PSH proposals that meet specific needs in our systems, that are backed by experienced parties who can manage the development risks, and that can be shown to provide benefits to our customers that exceed the benefits of other storage technology providers, we will consider PSH storage in future solicitations for storage resources.

[66] *E-storage: Shifting From Cost to Value Wind and Solar Applications*. World Energy Council. 2016. Table 6a:”Assumptions underpinning development of specific cumulated investment costs to 2030”.

Hydrogen Energy Storage. According to NREL: "… hydrogen can play an important role in transforming our energy future if hydrogen storage technologies are improved."[67]

Hydrogen is a versatile energy storage carrier, with high energy density, a that holds significant promise for use in stationary, portable and transport applications. Hydrogen could be used to "de-carbonize" applications that rely on natural gas. In electricity applications, hydrogen can be produced through electrolysis with "excess" variable renewable energy (for example, energy available for production by wind and solar resources at times when the net system demand for electricity is low). Hydrogen can be stored under pressure is storage vessels, or underground caverns. The stored hydrogen is then used in fuel cells for production of electricity, thus providing a means of load shifting in systems with high penetrations of variable renewable resources.[68]

While Europe has a relatively robust commercial supply chain for hydrogen production and storage for industrial uses,[69] hydrogen storage technology for electricity is still in the research and development phase. In the United States demonstration projects have been constructed that integrate wind turbines and solar PV with electrolyzer systems to produce hydrogen. A significant challenge towards commercialization of hydrogen energy storage for electricity applications is the ability to scale the systems to larger sizes.[70]

We believe that hydrogen energy storage systems hold great promise. However, at this time the availability of commercial hydrogen energy storage systems is limited. We will continue to monitor developments in this technology, and as appropriate, include hydrogen energy storage in future power supply plan updates. In the meantime, we believe lithium-ion BESS provides a useful "price to beat" reference for emerging technologies such as hydrogen storage for electricity applications.

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[67] http://www.nrel.gov/hydrogen/proj_storage.html.

[68] *Program on Technology Innovation: Hydrogen Energy Systems Development in Europe*, Technical Update 3002007274. Electric Power Research Institute, January 2016.

[69] *Ibid.*

[70] http://www.renewableenergyworld.com/articles/2014/07/hydrogen-energy-storage-a-new-solution-to-the-renewable-energy-intermittency-problem.html.

E. System Security

FACTORS OF SYSTEM SECURITY

System security (or Operating Reliability) is defined by NERC as *the ability of the system to withstand sudden disturbances*.[71] These disturbances or contingencies can be the loss of generation or electrical faults that can cause sudden changes to frequency, voltage and current. Operating equilibrium following these disturbances must be restored to prevent damage to utility and end-use equipment, and to ensure public safety.

Security is maintained by operating the system with sufficient inertia, limiting the magnitude of the contingency event, and maintaining adequate contingency reserves and fault current.

Inertia: the electrical system includes many rotating components which have inertia, including traditional synchronous generators (large rotating electromagnets coupled to heavy turbines or internal combustion engines), and rotating customer loads (usually induction electrical motors connected to appliances, pumps). During a contingency, the inertia in these rotating masses opposes changes to their rotational speed (that is, oppose changes to system frequency). Hence, an electrical system with high inertia is more robust and can withstand contingency events better than a low inertia system.

Operational actions to protect against contingencies: 1) limit the magnitude of the disturbance; 2) reconfigure the system to mitigate risks; and 3) ensure the system is carrying the necessary contingency reserves to mitigate the adverse effects of these contingency events.

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[71] NERC, *Definition of "Adequate Level of Reliability"*, December 2007, http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

Fault protection: synchronous generators provide sufficient system fault current to activate protective relay schemes within the critical clearing times of transmission lines and generators. System fault current is also required to ensure protective relay schemes at the distribution system can detect and isolate downed power lines to ensure public safety and prevent equipment damage.

Resource planning must incorporate fundamental system security parameters because online resources can affect both the magnitude of the disturbance and the ability of the system to respond. For example, the size of the largest resource on the system defines the largest contingency that must be protected against, and the characteristics of available resources determine the system response.

On island systems with very high levels of wind and solar resources, the most critical security concern is displacement of thermal generators, reducing system inertia and the available system fault current.[72] This concern dominates because (a) the largest loss of generation contingency becomes a larger percentage of the total supply; and (b) the large contingency on the low inertia system will require multiple blocks of under frequency load shed (UFLS) to stabilize system frequency. While there are other potential system security concerns, such as voltage stability and reactive power capacity, mitigating these issues can be somewhat independent of the resource plan. [73] As such, this PSIP filing we will focus exclusively on frequency analysis and short circuit evaluations.

System security considerations are incorporated into this PSIP Update in a supportive role and will not constrain the candidate resource plans beyond limiting the magnitude of the contingency as stated above. Currently, thermal generators provide the necessary system security attributes but at some point in time, technology-neutral resources will be available in sufficient capacities to augment and replace these attributes.

Each candidate resource plan will be evaluated to determine if system security requirements are met. If not, we will determine the necessary technology-neutral resources to bring the plan into compliance system requirements. This may initiate another cost production iteration for the given resource plan.

[72] Low short-circuit current also affects power quality.

[73] For example, static VAR compensators can provide voltage regulation and MVAR capacity, and some inertia.

Balancing Supply-Demand Fluctuations

Electric systems have to obey the conservation of energy law. Supply must always equal demand to maintain system frequency at 60 Hz. The automatic generation controls (AGC) must constantly dispatch regulating reserves to maintain this balance over various timeframes. As more variable resources are integrated into the system, the capacity and ramping requirements of the system's regulating reserves will increase. Similar to the issues of lower system inertia and available fault current, displacement of thermal generation reduces the online regulating reserve capacity of the system so DER/DR resource and/or central station storage will be required to maintain system frequency within acceptable limits.

Like system security, the need to balance supply and demand is incorporated into this PSIP Update. We first design resource strategies based on load and RPS requirements. We then determine if the system has adequate regulation and adequate ramping to follow net load, primarily driven by the characteristics of the variable generation resources. If regulating reserves are not adequate, technology-neutral alternatives will be added with the objective to minimize cost and other impacts of such modifications.

OVERVIEW OF APPROACH

The process of identifying needs and designing solutions follows a several-step process that we believe addresses the Commission's concerns regarding the prior PRIP filing. (Note that this process was outlined as six steps in the Companies' December 2015 filing. The revised process is equivalent, but reorganized to complement the rest of the PSIP more clearly.) The five steps are:

1. Establish operational reliability criteria.
2. Define technology-neutral ancillary services for meeting reliability criteria.
3. Determine the amount of ancillary services needed the support the resource plan.
4. Find the lowest reasonable cost solution, considering all types of qualified resources.
5. Identify flexible planning and future analyses to optimize over time.

Step 1: Establish Operational Reliability Criteria

The ultimate criterion for system security is straightforward to specify: ensure public safety, protect utility and end-user equipment, minimize load shedding events and prevent an island-wide blackout. The original PSIP was developed to meet the requirements of HI-TPL-001.

In this PSIP Update, we revised HI-TPL-001 to focus specifically on single contingency loss of generation events to determine acceptable UFLS capacities. For O‘ahu, HI-TPL-001 was revised to no UFLS for single generator contingency events while Maui and Hawai‘i Island allow 15% system load. The Moloka‘i and Lana‘i systems were removed from HI-TPL-001 since these systems are unique island distribution systems that do not qualify as transmission systems. Further revisions to HI-TPL-001 are required for multiple contingency events, both loss of generation and/or loss of transmission elements.

Under-frequency load shedding (UFLS) is a means to restore system frequency to operating equilibrium for various loss of generation contingency events. Ultimately, it is the last line of defense of system security to prevent system blackouts but it has shortcomings for future conditions in Hawai‘i. Under high levels of distributed PV penetration, the residential load net of PV is reduced so UFLS schemes are less effective, compromising system security. Instead of disconnecting distribution circuits, future UFLS schemes must incorporate a more surgical approach to maintain sufficient capacities during the day to be effective.

Minimum Fault-Current: Electrical faults are the most severe disturbance that can cause extensive damage to equipment and pose a safety risk to the public. Protective relay schemes are designed to locate and isolate these faults within cycles to ensure equipment protection and maintain system reliability. However, if the system fault current is insufficient, protective relays cannot detect and isolate the faulted element as designed. Downed transmission lines that cannot be isolated appear as a large system load, causing localized “brown-outs” could trigger extensive UFLS. This also poses a safety risk to both equipment and the public.

Step 2: Define Technology-Neutral Ancillary Services for Meeting Reliability Criteria

Any electric system has three fundamental real power ancillary service needs, presented in order of speed of response.

Frequency Response is needed to reduce the rate of change of frequency (RoCoF) to help stabilize system frequency immediately following a sudden loss of generation or load.

Regulation is needed to meet short-term changes in load and supply within seconds and minutes, because of solar fluctuations or the variable wind resources.

Replacement Reserves are needed to restore the faster services (above) after they are deployed, in order to be ready for the next event or further changes in net load.[74]

[74] The North American Electric Reliability Corporation (NERC) refers to these three services as “Primary Control”, “Secondary Control”, and “Tertiary Control”, respectively. (See NERC *Balancing and Frequency Control* Technical

Replacement Reserves are deployed in the minutes-to-hours timeframe and provide capacity to restore system frequency to 60 Hz following a contingency event or supplement Regulating Reserves because of forecast errors.

Other system operators define their ancillary services to serve these same basic needs, but each one's specific services depend on its system characteristics and history. The Electric Reliability Council of Texas (ERCOT) has proposed to re-design its Frequency Response as increasing renewable penetration raises new challenges in its "islanded" system separated from the rest of the mainland. However, system operators within large interconnected systems such as the Eastern Interconnection do not explicitly define Frequency Response products since the system has a vast amount of inertia to support frequency naturally.

The ancillary services products we propose for the Hawaiian Islands look like those being proposed in ERCOT, with a few additional elements to address Hawaiian-specific needs: the small systems here are vulnerable to over-frequency in the event of a load trip. Fast Frequency Response Down would address that problem without having to rely on downward reserves from generators running at higher-than-economic output levels, as is current practice.

Table E-96, Table E-97, and Table E-98 presents the real power services proposed for Hawai'i, along with technical specifications that any resource type would have to meet in order to provide that service.

Note that this table does not include fault-current since the protective relay schemes are designed to operate with synchronous generators. Therefore, identifying cost effective technology-neutral products will not be pursued at this time. Fault current can be provided by online generators while they are required by the resource plan for meeting system demand and, once retired, by converting those generators to synchronous condensers that do not produce power but can provide fault current, voltage regulation, and reactive power (MVARS).

The Companies recognize that these definitions deviate from the Grid Services definitions filed in the Supplemental Report under the IDRPP (Docket No. 2007-0341) in November of 2015. These reflect further refinement to the services as defined in that filing and the Supplemental Report will be updated to reflect the refined service definitions.

Document prepared by the NERC Resources Subcommittee, Jan 26, 2011.) We use the more descriptive titles for greater clarity.

Frequency Response

Reduce the rate of change of frequency (RoCoF) within cycles after a contingency, providing more time for PFR to deploy.

Frequency Response: Real-Power Ancillary Services		
Instantaneous Inertia (II)	Reduce the rate of change of frequency	
Examples of Suitable Resources	*Equipment Requirements*	*Performance Requirements*
■ Synchronous generators (incl. pump storage) and flywheels ■ Synchronous motor loads also provide inertia; Hawaiian Electric may plan around them but wouldn't procure or control them ■ Synchronous condensers	■ Spinning mass electromagnetically coupled to grid	■ Natural characteristics of synchronous generators ■ Proportional response to changes in speed
Primary Frequency Reserves (PFR)	Stabilize frequency in either direction w/response proportional to changes in speed or frequency	
■ Synchronous generators ■ Inverter-interfaced generators and storage	■ Governor or control system meeting minimum performance requirements for droop and deadband	■ Initiation governed by deadband less than ±X Hz ■ Linear response to changes in speed or frequency ■ Time to max: a few seconds (for example, 16 seconds in ERCOT FAS) ■ Duration: TBD based on Replacement response time
Fast Frequency Reserves 1 Up (FFR1Up)	Reduce the rate of change of frequency w/response proportional to the generation contingency	
■ Very fast-response resources (likely central station), such as batteries, flywheels, and curtailed PV	■ Control system capable of responding to signals within specified response time ■ 2-way real-time communications	■ Trigger: signal from large trip or df/dt ■ Initiation time and time to max: several cycles (for example, six cycles total reaction time, as determined by Hawai'i Electric Light contingency reserve storage study) ■ Duration: TBD based on Replacement response time and resource capabilities (for example, 10 minutes in ERCOT; 30 minute in Hawai'i Electric Light to allow replacement by gas turbine.)
Fast Frequency Reserves 2 Up (FFR2Up)	Reduce the rate of change of frequency w/response proportional to the generation contingency	
■ Distributed resources w/autonomous control, including DR from fairly constant loads that can curtail nearly instantaneously	■ Under-frequency relays that can respond within specified response time ■ 1-way real-time communication (user to operator) to allow operator to measure how much load is available to curtail	■ Trigger: df/dt ■ Initiation time (and time to max): a fraction of a second, but slower than FFR1 (for example, 0.5 seconds in ERCOT FAS) ■ Duration: TBD based on Replacement response time and DR capabilities (for example, 1 hour in ERCOT FAS)
Fast Frequency Reserves Down (FFRDown)	Quickly restore supply-demand balance following a loss of load; reduces operational down reserves form synchronous generation	
■ Inverter-interfaced generators and storage ■ Distributed resources w/autonomous control, including DR from loads that can increase almost instantaneously	■ Over-frequency relays that can respond within specified response time ■ 1-way real-time communication (user to operator) to allow operator to measure how much generation is available to drop or load is available to increase	■ Trigger: df/dt ■ Initiation time (and time to max): a fraction of a second, similar to FFR2 (for example, 0.5 seconds in ERCOT FAS) ■ Duration: TBD based on Replacement response time and resource capabilities (for example, 1 hour in ERCOT FAS)

Table E-96. Frequency Response: Real-Power Ancillary Services

Regulation

Meet second-to-second and minute-to-minute net load fluctuations around trend and forecast errors, until Replacement can take over; help restore frequency after contingencies.

Regulation: Real-Power Ancillary Services		
Regulation Reserves Up (RegUp)		
Examples of Suitable Resources	*Equipment Requirements*	*Performance Requirements*
■ Synchronous generators ■ Battery energy storage, flywheels ■ Inverter-interfaced generation (for example, curtailed wind/PV) ■ DR might meet "continuously controllable" requirements, incl. industrial loads, EVs, aggregated smaller on-off loads (e.g, heaters, compressors)	■ 2-way real-time communication to allow exchange of AGC signal and signal response with operator ■ Continuous controllability	■ Continuously follow AGC control signals with sufficient accuracy ■ Time to max: minutes (for example, 5 minutes in ERCOT) ■ Duration at max: TBD based on Replacement response time and resource capabilities (for example, 1 hour in ERCOT)
Regulation Reserves Down (RegDown)		
■ Similar to RegUp plus small load banks	■ 2-way real-time communication to allow exchange of AGC signal and signal response with operator ■ Continuous controllability	■ Similar to RegUp, but in the other direction

Table E-97. Regulation: Real-Power Ancillary Services

Replacement

Replace output of faster reserves (or restoration of shed loads) so they could deploy again; meet sustained ramps and forecast errors beyond Regulation duration.

Replacement: Real-Power Ancillary Services		
Replacement Reserves (RR)		
Examples of Suitable Resources	*Equipment Requirements*	*Performance Requirements*
■ Generators ■ DR that cannot react fast enough to provide FFR ■ Energy storage	■ One-way communication (operator to user) and controls to remotely curtail loads	■ Response time(s): TBD based on needs and resource capabilities. Consider two response times (for example, 10 and 30 minutes in ERCOT FAS) ■ Duration: TBD based on needs and resource capabilities (for example, 1 hour in ERCOT FAS) ■ Full deployment capability by the set Response Time(s) (for example, 10 minutes or 30 minutes)

Table E-98. Replacement: Real-Power Ancillary Services

Step 3: Determine the Amount of Ancillary Services Needed to Support the Resource Plan

The amounts of each type of ancillary service needed to meet system security vary by island, resource strategy, and time period. That is because Frequency Response needs are driven by the size of the largest contingency, which is generally the largest unit online at the time. Regulation needs are driven by the variability of net load (that is, load minus renewable generation output), which depends especially on the amount of PV and wind. And Replacement reserve needs are driven by the amounts of Frequency Response and Regulation needed.

Frequency Response Requirements. Our analytical methodology for determining the necessary amounts of Frequency Response services builds upon the FFR analyses performed in the Integrated Demand Response Portfolio Plan Supplement: System Response Requirements dated November 6, 2015 (Docket No. 2007-0341). Fast Frequency Reserve requirements will be determined for a range of system inertia, system load, and PFR for the largest contingency. Fast Frequency Reserves 1 (FFR1) is modeled as a step change in the 12 cycle timeframe and FFR2 is modeled with df/dt in the 30 cycle timeframe.

Fast frequency reserve requirements will also be determined for each resource plan to ensure system security requirements are met. The O‘ahu and Hawai‘i Island systems do not meet standard HI-TPL-001 for loss of generation contingency events so FFR analysis will be performed in 2019. Maui already has a BESS but analysis will be performed to determine if additional FFR is required to meet HI-TPL-001.

Beyond 2019, specific years will be analyzed for each resource plan to ensure compliance with HI-TPL-001. The resource plans will determine what years will be selected for analysis. Typically, analysis will be driven by the need to cycle thermal units offline to meet RPS or changes to system resources. In any event, thermal units will not be required to meet system security requirements beyond a reasonable timeframe when synchronous condensers and FFR are available in sufficient capacities.

It’s important to note that the frequency response from synchronous generators is proportional to the magnitude of the contingency, whether its inertial response, primary (governor) response, or exciter and field forcing. Large steam turbines are better equipped to respond to an under frequency event as opposed to an over frequency event so preservation of this principle of proportional frequency response is critical to maintain system security. Over compensation from DR or DER to an under frequency event will likely cause more problems that the initial loss of generation contingency therefore managing this risk as these resources come online will be essential to maintain system reliability.

To simulate the performance of autonomous-controlled inverter-based systems, DER resources will be modeled with droop response. Droop response is inversely proportional to the system's frequency response profile so this resource would be characterized as PFR.

Regulation Requirements. Our methodology for determining the amount of Regulation needed is described in System Operating and Reliability Criteria (page 4-21).

Replacement Reserve Requirements. All systems currently have quick-start generation. With the addition of the Schofield units and resource plans, O'ahu will have approximately 200 MW of quick-start generation so additional RR reserves to supplement or displace this capacity may not be required in the near future. The system's RR requirements are dependent on FFR and RR capacities and performance. Once these DR/DER resources have been identified and characterized, RR capacities can be evaluated and technology-neutral resource benefits quantified.

Fault Current Requirements. For O'ahu, minimum fault current levels for three phase, line-to-line, and single line to ground faults are established for each substation 46kV bus. Simulations were performed to determine the number of thermal units required to meet minimum fault current levels. This ensures proper operation of protective relay schemes.

For the Maui and Hawai'i Island systems, the fault current capacity provided by the current must-run thermal units will be maintained.

Additional System Security Analyses. Besides the analyses to determine ancillary service requirements, the following sensitivity analyses will be performed and one or more resource cases:

- Fault analysis to determine the impacts of the loss of legacy PV because of over frequency events.
- Fault analysis to determine the impacts of the loss of DG-PV with no under voltage ride-though requirements (point of interconnection voltage < 0.5 PU)
- UFLS sensitivity analyses to determine the impacts of reduced capacities because of high DG-PV.

Step 4: Find Lowest Reasonable Cost Solution Considering All Types of Qualified Resources

All of the Ancillary Service needs are defined in technology-neutral terms so any qualified resource can meet them, whether traditional generation, advanced features of inverter-interfaced generation and storage, or demand response. Our objective is to identify the lowest reasonable cost combination that ensures system security for a given resource plan and in subsequent iterations, let the market and specific resource applications determine available resources. To do so, we break the analysis into three steps: we start by constructing an initial pre-DR solution that meets system security needs; then substitute DR to the full extent it is cost-effective, producing a revised resource strategy; finally, we consider whether the modifications in Step 2 warrant another iteration of analysis.

As stated earlier, thermal units are required to provide system fault current from 2016 through a period of time when retired units can be converted to synchronous condensers as dictated by the resource plan. To reduce potential curtailment in the interim, fossil fired steam units can operate in in VPO[75] if available.

We develop the initial pre-DR solution to meet the Frequency Response requirement as follows (recall that the Frequency Response need was reduced to an FFR requirement, as described in the prior step): In the pre-DR solution, we first assess how much FFR2 is required to meet HI-TPL-001. We then determine if FFR2 capacities are sufficient and if not, evaluate alternatives to meet system security requirements. This could be to limit the magnitude of the contingency, supplement FFR2 with increased system inertia (operate units in VPO if available), or supplement FFR2 with FFR1.

The initial pre-DR solution meets Regulation needs from the lowest-cost available resources by including regulation as a minimum "spinning reserve" constraint in the dispatch model. If not enough regulation is available, batteries or other resources are added. Note that these needs have already been met before determining Frequency Response needs and solutions.

Once we have a pre-DR solution that meets system security, we determine how much DR can meet the AS technical requirements and cost-effectively substitute for the pre-DR resources.

Finally, after having added DR and other resources to support system security, we assess whether another iteration of system security analysis is warranted. For example, if the amount of synchronous generation decreases substantially, more FFR or system inertia may be needed.

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[75] Variable Pressure Operation entails partial burner operation with lower operating pressures. This lowers the operating load at the expense of lower or negligible reserve capacities for dispatch.

Step 5: Identify Flexible Planning and Future Analyses to Optimize Over Time

The PSIP provides a framework to support future decision-making, not a set-in-stone plan. It recognizes the need for flexibility. It recognizes that actual future procurement decisions will incorporate new information and sharpen specific analyses that are not practical or appropriate for the PSIP. But the PSIP can identify ways to maintain flexibility, and future developments to look for, and some of the analyses to conduct when decisions have to be made.

Future analyses may include the following:

- Steady state load flow and transient analysis tools to transmit DER to the transmission system
- Damping of oscillatory instabilities for a low-inertia system. Siemens PSS®E is limited to point in time contingency events and is not suited to analyze instability caused by frequency oscillations
- Power quality impacts to the transmission system
- Smart inverter controls and characteristics required to meet system security
- Effects of Rapid Transit in O‘ahu

Some of these analyses will require modeling tools and/or outside support.

SYSTEM SECURITY PRELIMINARY RESULTS

Some preliminary results are available for this interim filing. For the Updated PSIPs, these preliminary results will be refined and extended to all resource strategies and islands.

Fault Current requirements are available for all islands:

- O‘ahu: 482.6 MVA
- Maui: 101.3 MVA
- Lana‘i: 5.5 MVA
- Moloka‘i: 5.5 MVA
- Hawai‘i Island: 140 MVA

Thermal generation provides the required system fault current until units are retired and generators can be converted to synchronous condensers. In the near term, fault current requirements should not result in substantial curtailment of renewable generation. If unit retirements are not in a resource plan, new synchronous condensers can be installed.

Frequency Response. Preliminary results for Fast Frequency Reserves (FFR) requirements are available for O'ahu only. Before 2022, the largest contingency is an AES turbine trip (180 MW plus 20 MW auxiliary load) and the loss of 55 MW legacy PV. Results of previous analysis determined the need for a 130 MW BESS (130 MW of the fastest FFR or FFR1). For this PSIP update, the retirement of AES in 2022 reduces the contingency to the loss of Kahe 5 or Kahe 6 and 55 MW of legacy PV. Results of preliminary analysis indicate that 90 MW of FF R1 is required for meet this contingency in 2019.

The 90 MW of FFR1 must be supplemented with slower FFR (FFR2) to manage an AES turbine trip. As of this update, the analysis to determine the amount of FFR2 has not been completed.

Preliminary analysis has been performed to model DER resources on droop control to supplement the 90 MW of FFR1 in lieu of FFR2. For the low-inertia unit commitment case, approximately 180 MW of additional Primary Frequency Reserves (PFR) at 3% droop response is required for an AES turbine trip at full output plus 55 MW of legacy PV. If PFR is modeled at 1% droop, the capacity decreases to 90 MW.

After 2022 when AES is deactivated, resource plans consider limiting the magnitude of the single contingency to be consistent with the size of the BESS already installed or a maximum of 200 MW based on the installation of a 130 MW BESS. This includes firm and as-available resources as well as the rating of an inter-island cable and associated power converters. In 2045, the magnitude of the contingency could be the loss of an 80 MVA distribution transformer for resource plans with high DER and minimal firm generation like HPOWER. Understanding the 2045 contingencies will help guide the resource planning process on unit ratings and contingencies.

Note that the distribution system's infrastructure must have sufficient reserve capacity to accommodate FFR2. The amount of reserve capacity will be dependent on the location and capacity of the DER. Analysis must be performed to ensure FFR2 capacities do not exceed the thermal limits of the distribution system for resource plans with high DG-PV penetrations.