Hawai‘i Electric Light Power Supply Improvement Plan

August 2014

Hawaiian Electric
Maui Electric
Hawai‘i Electric Light

Hawai‘i Electric Light submits this Power Supply Improvement Plan to comply with the Decision and Order issued by the Hawai‘i Public Utilities Commission on December 20, 2013 in Docket No. 2012-0212, Order No. 31758, and with our subsequent letter dated June 4, 2014 in Docket No. 2012-0092. The Companies retained Black & Veatch, Boston Consulting Group, Electric Power Systems, HD Baker and Company, PA Consulting Group, and Solari Communication to assist in the creation of this plan.

The Hawaiian Electric Companies created this PSIP based, in parts, on a realization of the current state of the electric systems in Hawai‘i, forecast conditions, and reasonable assumptions regarding technology readiness, availability, performance, applicability, and costs. As a result, this plan presents a reasonable and viable path into the future for the evolution of our power systems. We have attempted to document and be fully transparent about the assumptions and methodologies utilized to develop this plan. We recognize, however, that over time these forecasts and assumptions may or may not prove to be accurate or representative, and that the plan would need to be updated to reflect changes. As we move forward, we will continually evaluate the impacts of any changes to our material assumptions, seek to improve the planning methodologies, and evaluate and revise the plan to best meet the needs of our customers.

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Executive Summary

This Power Supply Improvement Plan (PSIP) defines Hawai‘i Electric Light’s vision for transforming the electric system to meet customer needs, implement the State of Hawai‘i’s policy goals, and secure a clean and affordable energy future. Based on the Company’s ongoing strategic planning efforts, the PSIP includes a realistic, flexible and operable tactical plan (the “Preferred Plan”) that recognizes our collective goals and the realities of our situation. For Hawai‘i Island, the PSIP increases renewable content of electricity to approximately 92% by 2030, and reduces full service residential customer bills, on average, by 30% in real terms. For the Hawaiian Electric Companies the consolidated renewable content of electricity increases to approximately 67% by 2030.

We take our obligations to our customers seriously. This report represents enormous amounts of thoughtful and thorough analysis to provide the most credible plan possible for our customers.

OUR SHARED VISION

Our vision is to deliver cost-effective, clean, reliable, and innovative energy services to our customers, creating meaningful benefits for Hawai‘i’s economy and environment, and making Hawai‘i a leader in the nation’s energy transformation. Hawai‘i has the potential to become a national model for clean energy by not only achieving the highest Renewable Portfolio Standard (RPS) goal in the nation in 2030, but also by leading the way to define the utility model of the future.

To achieve this, we believe the Hawaiian Electric Companies have a responsibility and a unique opportunity to evolve in Hawai‘i’s complex and rapidly changing energy ecosystem. In this dynamic environment, no single party can realize this future for

Hawai‘i. For this reason, we seek a shared vision with our customers, regulators, policy makers and other stakeholders in order to achieve shared success for all of Hawai‘i.

THE PSIP ACHIEVES UNPRECEDENTED LEVELS OF RENEWABLE ENERGY

The Hawaiian Electric Companies will not just meet the mandated RPS of 40%, but will achieve an unprecedented level of 67% by 2030. As illustrated in Figure ES-1 and Figure ES-2, for Hawai‘i Island, the Hawai‘i Electric Light Preferred Plan increases the already aggressive Hawai‘i Electric Light RPS from 60% in 2015 to 92% in 2030. A significant amount of distributed solar photovolatic (PV) is included in the Preferred Plan and accounts for about one-fourth of this total.

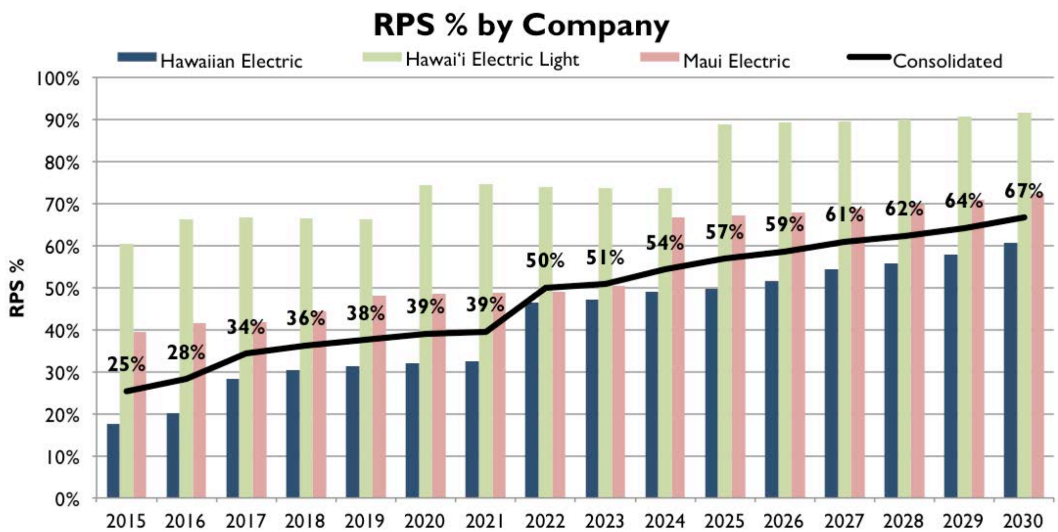

Figure ES-1. Renewable Portfolio Standard (RPS) for the Hawaiian Electric, Maui Electric, Hawai‘i Electric Light, and the Consolidated Companies, 2015-2030.

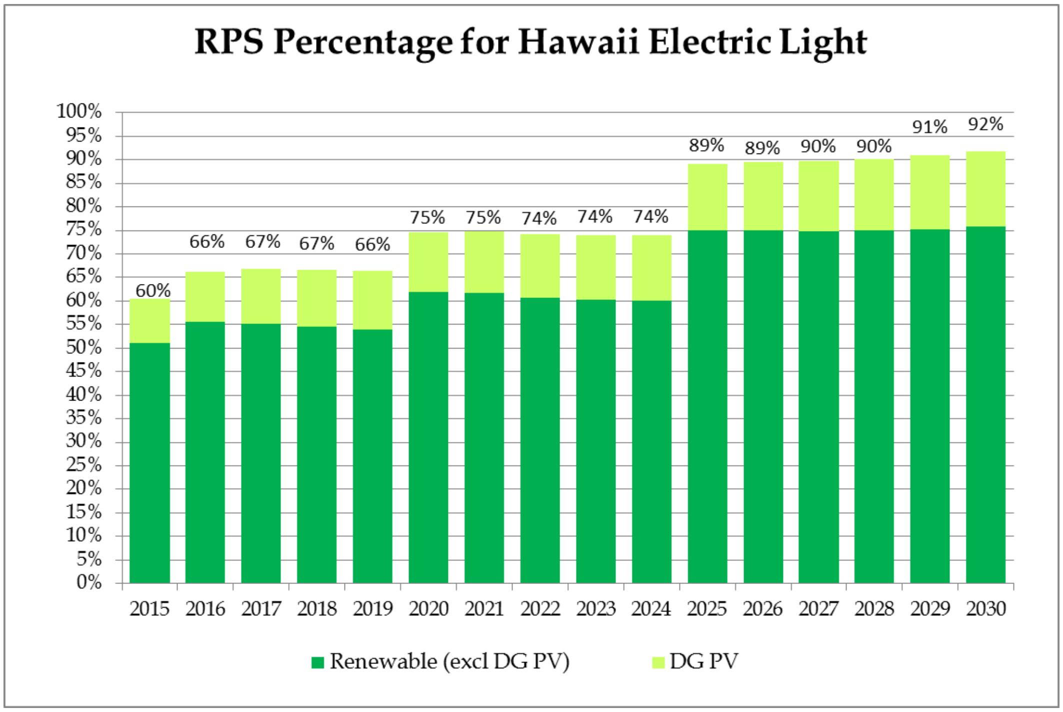

Figure ES-2. Renewable Portfolio Standard (RPS) for Hawai'i Electric Light on Hawai'i Island, 2015–2030, showing the relative contribution from distributed generation (DG-PV)

Maximizes Utilization of Renewable Energy

From 2015 through 2030, 97.3% of the estimated energy produced from all renewable resources during the planning period would be utilized (not curtailed) each year (Figure ES-3). This is accomplished by:

- Installing energy storage to provide regulating and contingency reserves.
- Incorporating demand response as a tool for system demand shaping and management.
- Levering the high degree of operational flexibility of existing thermal generation resources.
- Using new renewable, dispatchable resources to provide system security and reliability needs in place of thermal generation.

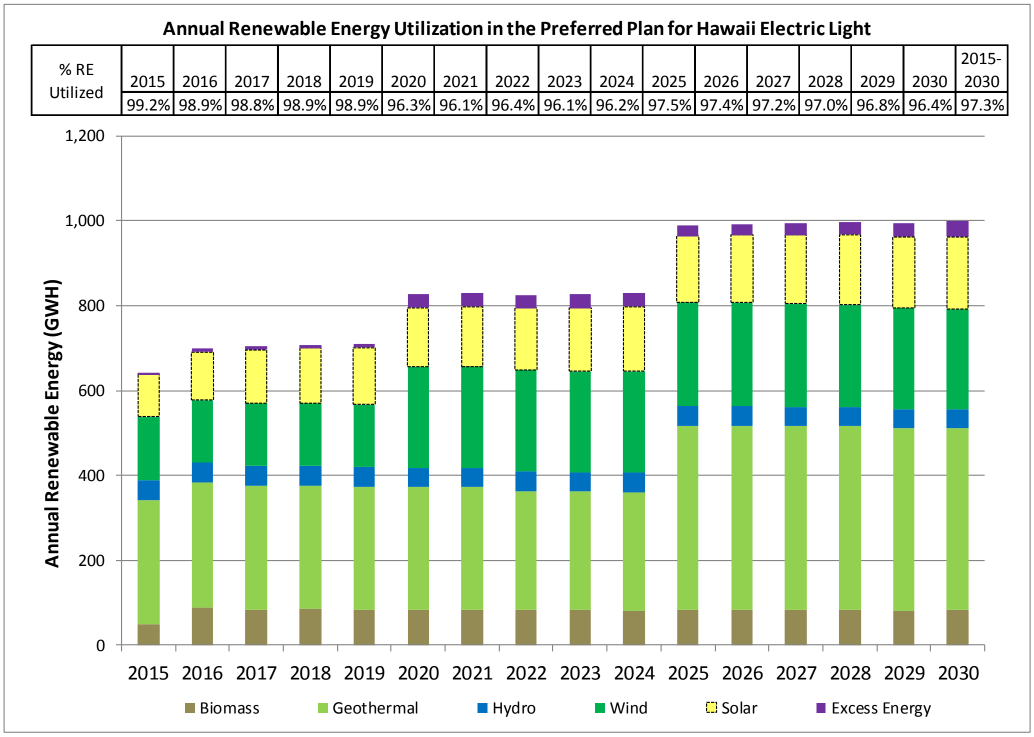

Figure ES-3. Total System Renewable Energy Utilized by Hawai‘i Electric Light

The Preferred Plan Provides a Hedge Against Fuel Price Volatility

In developing the Preferred Plan, conscious choices were made to incorporate changes that result in stabilizing costs, providing a diversified portfolio, and maintaining a reliable power system. The plan uses LNG to provide cost benefits in the near term. Two non-fuel resources (geothermal and wind) are added and will allow reductions in our dependence on fossil-fuel resources. These measures are being done, in part, to provide a financial hedge against fuel price volatility and future uncertainty with respect to fuel availability.

When the analysis result showed a “close call” between a renewable and non-renewable option, the renewable option was chosen. The respective effects of fuel price volatility were a consideration for the Preferred Plan. The selections of new renewable generation resources for inclusion in the Preferred Plan included consideration of economics, planning flexibility, and system operational requirements; these selections also included location and technical/operational characteristics, which allow those resources to displace thermal generation while maintaining system security and operability.

Full consideration was also given to the portfolio value that demand response[1] and energy storage technologies, both non-fuel consuming options, can provide; both were found to have valuable contributions.

OVERVIEW OF THE PREFERRED PLAN

Energy Mix

Figure ES-4 illustrates the energy mix for Hawai'i Island from 2015 to 2030. Renewable energy from DG-PV continues to grow over time; new utility-scale wind and geothermal resources are added to the system. As these system changes and resource additions reduce the need for energy and capacity from the steam units, the steam units are deactivated and decommissioned. Oil is largely replaced by liquefied natural gas (LNG) and biomass (at the Hu Honua generating plant, scheduled for operation in 2015). Later, the future renewable wind and geothermal additions reduce reliance on LNG.

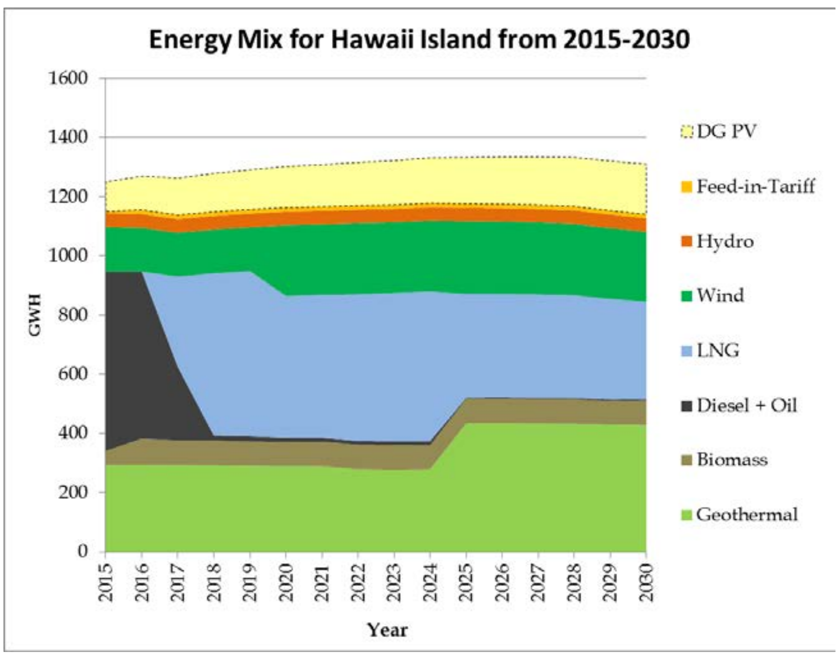

Figure ES-4. Annual Energy Mix of Hawai'i Electric Light Preferred Plan

[1] As defined in the *Integrated Demand Response Portfolio Plan* (IDRPP), filed by the Companies on July 28, 2014.

The Hawai‘i Electric Light Preferred Plan for 2015-2030 for Hawai‘i Island can be summarized as follows:

- Increases customer-owned distributed generation three-fold.
- Aggressively expands demand response programs.
- Adds a new 20 MW utility-scale wind facility in 2020 (assumed to be in a west Hawai‘i location).
- Adds 25 MW of dispatchable geothermal in west Hawai‘i in 2025.
- Installs energy storage for regulating and contingency reserves.
- Procures LNG for certain thermal generating units.
- Deactivates all the existing oil-fired steam generators.
- Modernizes the grid with smart technologies.

Timeline for the Preferred Plan

Figure ES-5 illustrates the timelines for the Preferred Plans for the Hawai‘i Electric Light power system on Hawai‘i Island for 2015–2030, which shows when new resources would be added (above the date line) and existing resources would be retired (below the date line).

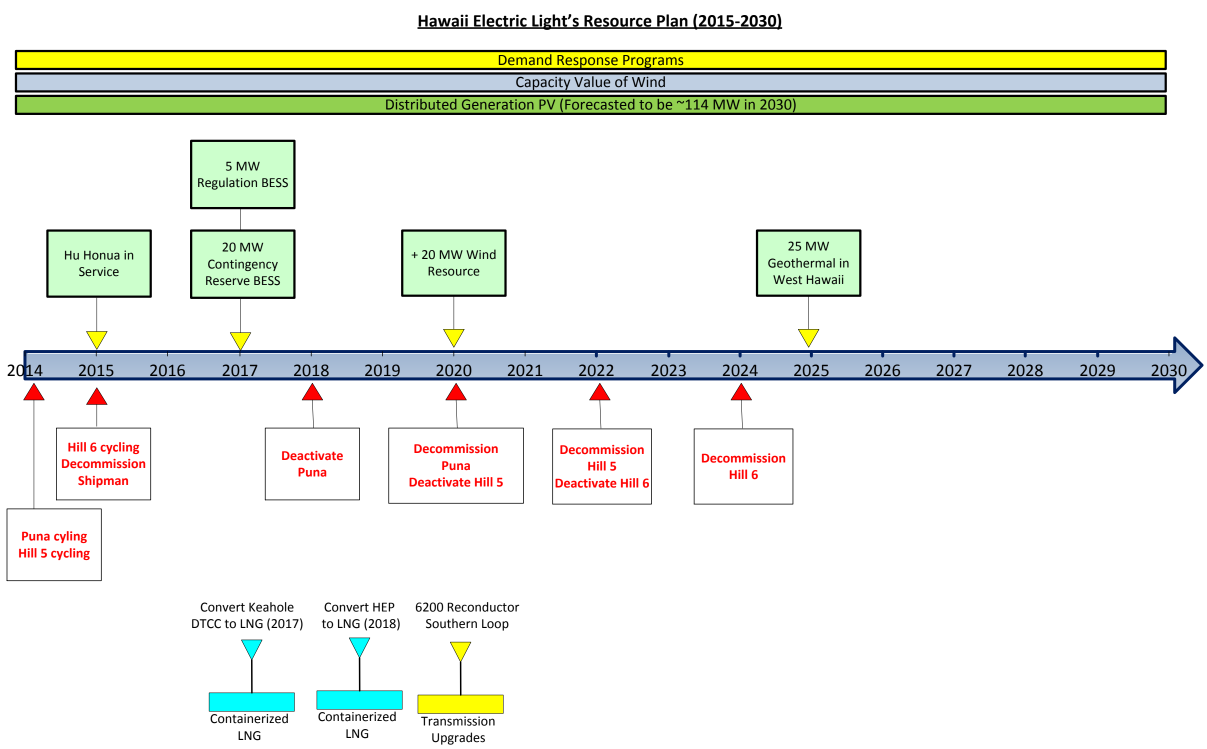

Figure ES-5. Hawai‘i Electric Light Preferred Plan 2015-2030 (Hawai‘i Island)

The Preferred Plan is Realistic

The Preferred Plan accomplishes our strategic vision of the 2030 power system in a way that is both realistic and achievable.

The Preferred Plan relies only on technologies that are commercially ready today and that can be successfully developed in Hawai'i's unique political and social environment.

Recognizing that the investment to implement the Preferred Plan will be substantial, and perhaps beyond the ability of a single entity to make, the plan assumes a mix of utility and third-party investment in new infrastructure. The Preferred Plan does not rely on a single large capital project to achieve success and thus, portfolio risk is well diversified.

Finally, the Preferred Plan is "operable". In other words, the plan is based on sound physics, engineering, and utility operating principles.

The Preferred Plan Reduces Customer Bills

The Preferred Plan identifies those transformational and foundational investments needed to reliably serve customers across Hawai'i Island with flexible, smart, and renewable energy resources.

The Preferred Plan, coupled with changes in rate design that more fairly allocates fixed grid costs across all customers (assumed effective in 2017), is expected to reduce monthly bills for average full service residential customers by 30% from 2014 to 2030 (Figure ES-6).

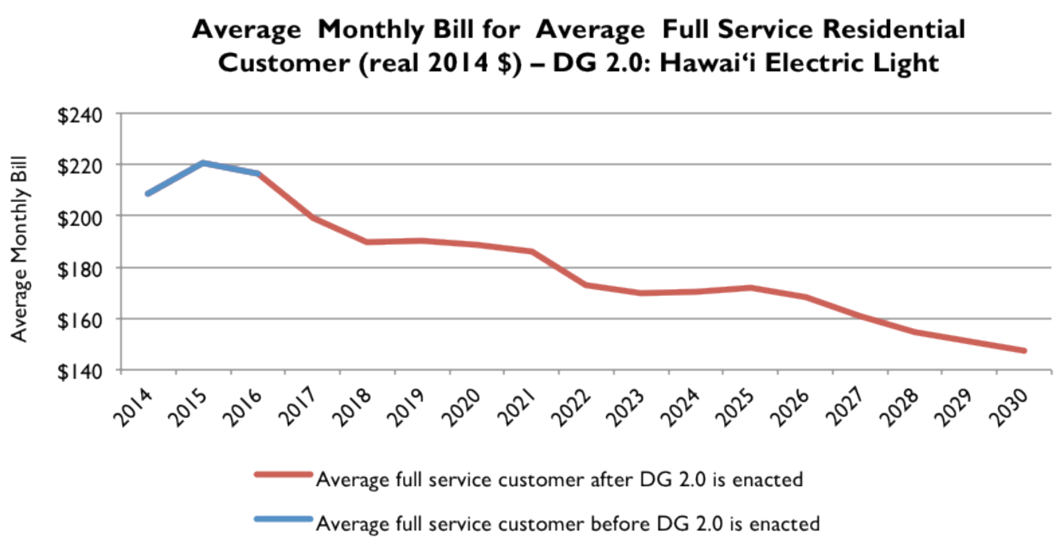

Figure ES-6. Average Full Service Residential Customer Bill Impact

The customer bill reductions are driven by projected changes in the underlying cost structures.

Fuel expense declines significantly over the planning period, driven by the continued shift toward renewable generation and the cost savings, beginning in 2017 with the introduction of LNG.

Purchased power costs increase over the planning period, reflecting both the expanding purchases of renewable energy and the capacity costs for replacement dispatchable generation.

Operations and maintenance (O&M) expenses are expected to decline in real terms across the planning period, driven by the reduced costs associated with Smart Grid and information technology investments.

The Preferred Plan is Flexible

The Preferred Plan is flexible and can be adjusted based on changing conditions as we move toward 2030.

Planning Flexibility: The ability to make adjustments regarding capital intensive resource decisions was accomplished through a combination of retiring less efficient power plants, and selecting new resources from a menu of generation, demand response programs, and energy storage options that can be developed in relatively short time frames.

Operational Flexibility: The renewable dispatchable generation resources are selected to provide operating capabilities, and where feasible, location to reduce reliance on thermal generation for system security and reliability. The plan leverages the high degree of operational flexibility from existing generation.

Technological Flexibility: The Preferred Plan can be immediately implemented using proven technologies that are available today. The Preferred Plan, however, is flexible enough to retain the ability to change the mix of future resources in response to system conditions that differ from those assumed today. The plan also allows for the incorporation of emerging technologies that may achieve commercial readiness or produce cost savings in the future. The plan incorporates flexibility in providing system security and reliability using various technologies: thermal generation, renewable generation, storage, demand response, and capabilities from distributed generation.

Financial Flexibility: The plan is agnostic with respect to ownership of incremental resource additions.

TRANSPARENCY

The planning approach we have taken provides our customers and other stakeholders with a transparent view of the options considered and the potential tradeoffs assessed as part of the planning analyses. To this end, we assembled numerous assumptions and forecasts critical to the analyses, and utilized sophisticated and comprehensive production simulation models to analyze alternatives. These models employed a variety of modeling techniques, and all were based on utility planning and operating methods with worldwide utility-industry acceptance.

Achieving the aggressive goals in this plan requires that all stakeholders be aligned in moving forward expeditiously. As with any planning process of this magnitude, the forecasts and assumptions incorporated in this PSIP may or may not be borne out. However, we made what we believed were logical and fair assumptions that support near-term actions.

EXECUTION OF THE PREFERRED PLAN

The Preferred Plan clearly identifies the strategic initiatives that must be implemented in order to continue the journey toward a more sustainable and affordable energy future.

The Preferred Plan is clear with respect to near-term actions that must be initiated on the path toward a realization of our shared vision. We are committed to do our part. We will continue to transform and collaborate to make this a reality. The Commission has already opened a docket to review our PSIPs. We look forward to the additional insight and any required approvals to keep moving toward our shared goals.

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1. Introduction

We operate in an environment that is defined by geography, changing technology, and policies intended to promote clean energy. These conditions create opportunities, as well as challenges, as we move into the future. We intend to adapt to changes in market and technological conditions to meet the challenges along the way. Accordingly, we have initiated a comprehensive strategic planning effort to position the Hawaiian Electric Companies to provide high value energy services to our customers, and promote the economic well being of Hawai‘i. Our plan is based on extensive analysis of the current situation and of future opportunities. We have integrated our findings into a Preferred Plan that increases renewable content of electricity in Hawai‘i to 67% by 2030 and reduces full service customer bills by 22 to 30%.

THE POWER SUPPLY IMPROVEMENT PLAN

The Hawaiian Electric Companies were ordered to create Power Supply Improvement Plans (PSIPs) for each operating utility. The resultant PSIPs are tactical, executable plans based on well-reasoned strategies that can be implemented expeditiously. They are supported by comprehensive analyses in resource planning, and focus on customer needs.

Goals of the PSIP

Utilizing a strategic "clean slate" view of 2030, we created a balanced portfolio of the optimal mix of generation, both thermal and renewable, demand response, and energy storage to:

- Successfully and economically integrate substantial amounts of renewable energy.
- Maximize the utilization of renewable energy that is produced.
- Maintain system reliability.
- Systematically retire older, less-efficient fossil generation.
- Reduce "must-run" generation.
- Increase generation operational flexibility.
- Utilize new technologies for grid services.

The result of our effort is a tactical *Preferred Plan* for each operating utility—that can be confidently and expeditiously implemented.

OVERVIEW OF THE PSIP

This document is organized as follows:

Chapter 1. Introduction: An introduction to and an overview of the contents of the PSIP.

Chapter 2. Strategic Direction: A high-level vision of our power grid in 2030.

Chapter 3. Generation Resources: The current state of our power grids.

Chapter 4. Major Planning Assumptions: A discussion of the major assumptions upon which we based our modeling analyses to develop the Preferred Plans.

Chapter 5. Preferred Plan: A presentation of our Preferred Plan to attain the goals of the PSIP.

Chapter 6. Financial Implications: An analysis of the financial impacts of implementing the Preferred Plan.

Chapter 7. Conclusions & Recommendations: A summary of the conclusions derived from our analyses and recommendations moving forward

Appendices A–O: A series of appendices that provide supporting information and more detailed discussions regarding the creation of the PSIP.

HAWAIIAN ELECTRIC SYSTEM LOAD PROFILES

System loads throughout the day on our electric power grids have changed dramatically over the past eight years. As an example of this change, Figure 1-7 shows this trend on the O‘ahu grid using data from the first week of June during the period from 2006 to 2014. This is not only an accurate representation for every week of a year on O‘ahu, but is also relevant for the Maui Electric and Hawai‘i Electric Light power systems.

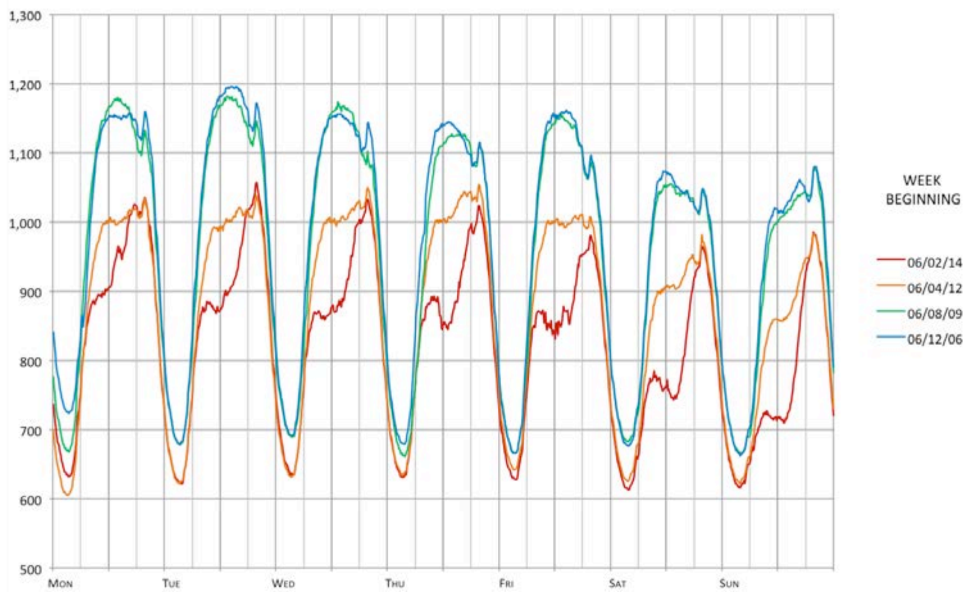

Figure 1-7. O‘ahu System Load Profiles, 2006–2014

A review of load profiles from recent years yields the following observations:

- Daytime peak loads on the O‘ahu grid in 2006 and 2009 regularly reached 1,200 MW; in 2014, daytime peak loads only reach approximately 850 MW: a drop of about 30%.
- Over the past four years, the summertime system load has shifted from a daytime peak to an early nighttime peak, due mainly to distributed solar generation.
- System minimum loads have also lowered, due mostly to energy efficiency measures.

This trend suggests that sales and peaks have declined which, coupled with the growth in distributed generation photovoltaics (DG-PV), is a harbinger for greater challenges operating a stable and reliable grid.

RENEWABLE ENERGY INTEGRATION AND DIVERSITY

The generation portfolio of the future will be comprised of greater amounts of variable renewable resources, complemented by firm thermal generation that will be both renewable and fossil fueled. The renewable energy will be derived from solar (both distributed generation and utility-scale generation), wind, hydroelectric, biomass (including waste), and geothermal resources. Energy storage and demand response will play integral roles in the grid of the future, while the role of fossil fuels will continue to diminish.

A Portfolio of Diverse Renewable Generation

The state of Hawai‘i is blessed with abundant sunshine, generous winds, and geothermal resources that can be harnessed for energy production, but no indigenous fossil fuels. Recognizing this, we have the most aggressive Renewable Portfolio Standard (RPS) in the nation. The Hawaiian Electric Companies are already on course to exceed the mandated RPS of 40% in 2030. Our PSIP further exploits Hawai‘i's natural resources, creating plans to significantly exceed the RPS requirements.

The Role of Thermal Generation

Even with an abundance of renewable energy resources, the power system must have a complement of firm, dispatchable thermal resources. Historically, these types of generators provided bulk power for transmission and distribution throughout the electric grid. In the future, they will be called upon to generate power during periods when variable renewable generation is unavailable (that is, periods of darkness, extended storms, or no wind), and to provide valuable grid services to sustain grid reliability. These thermal resources will be fueled by liquefied natural gas (LNG), which is lower cost and environmentally cleaner than petroleum-based fuels.

Energy Storage

Continued advancements in energy storage technology harbors increased opportunities for employing additional amounts of variable renewable resources onto the electricity grid at reasonable costs. Our PSIP analyzes and develops a plan for using energy storage systems (ESS) to maximize renewable energy utilization (minimize curtailment) and sustain frequency regulation and dynamic stability requirements.

Demand Response (DR)

Demand response can enable grid operations, save costs, and provide customers more options to manage their bills and be active contributors to the electric system. Power systems have historically controlled the supply of power to match the uncontrolled demand for power. Demand response programs empower customers and system operators to work collaboratively to balance load supply and demand through innovative technology and programs. Toward that end, we have designed and will implement DR programs[2] across the entire state, and have incorporated the utilization of DR in our Preferred Plans.

FINANCIAL IMPLICATIONS

The transformation of the power system will require significant investments by the company and third parties to build the necessary flexible, smart, and renewable energy infrastructure needed to reliably serve customers across the state. We have developed estimates of foundational and transformational investments that will need to be made during the planning period. And, through detailed hourly and sub-hourly production simulation modeling, have estimated the fuel, power purchase, operating, and maintenance expenses resulting from implementation of the Preferred Plans. A financial model was utilized to examine the financial implications of the PSIPs for customers.

OVERVIEW OF OUR PREFERRED PLAN

For each operating utility, we have developed a Preferred Plan for transforming the system's current state to a future vision of the utility in 2030 consistent with the Strategic Direction we set forth to achieve long-term benefits for our customers and our state (and is presented in Chapter 2).

Implementation of these Preferred Plans will transform the electric systems on O'ahu, Maui, Lana'i, Moloka'i, and Hawai'i, and will substantially decrease our reliance on imported fossil fuels and reduce customer bills while integrating tremendously high levels of renewable energy. More than 65% of our energy will be provided by renewable energy resources in 2030, significantly surpassing our state's renewable energy target and securing Hawai'i's place as a national leader in clean energy.

[2] The Companies filed its *Integrated Demand Response Portfolio Plan* (IDRPP) with the Commission on July 28, 2014.

Our Shared Vision

Our vision is to deliver cost-effective, clean, reliable, and innovative energy services to our customers, creating meaningful benefits for Hawai'i's economy and environment, and making Hawai'i a leader in the nation's energy transformation. Hawai'i has the potential to become a national model for clean energy by not only achieving the highest Renewable Portfolio Standard (RPS) goal in the nation in 2030, but also by leading the way to define the utility model of the future.

To achieve this, we believe the Hawaiian Electric Companies have a responsibility and a unique opportunity to evolve in Hawai'i's complex and rapidly changing energy ecosystem. In this dynamic environment, no single party can realize this future for Hawai'i. For this reason, we seek a shared vision with our customers, regulators, policy makers and other stakeholders in order to achieve shared success for all of Hawai'i.

2. Strategic Direction

A healthy, resilient and cost effective power supply and electric power delivery system is vital to the well being of the people of Hawai'i. The Hawaiian Electric Companies provide service to over 450,000 customers across five of the Hawaiian Islands, and because our customers expect and depend on reliable electric service, we are in contact with them every second of every day. We believe that a healthy, viable and progressive utility is imperative for managing, producing and delivering the electric energy that is essential to our economy.

We operate in an environment that is defined by geography, changing technology, and policies intended to promote clean energy. These conditions create opportunities, as well as challenges, as we move into the future. We intend to adapt to changes in market and technology conditions and to meet the challenges along the way. Accordingly, we have initiated a comprehensive strategic planning effort to position the Hawaiian Electric Companies to provide high value energy services to our customers, and promote the economic well being of Hawai'i.

While our strategic planning is an ongoing effort, the work that has been accomplished to date has defined Power Supply Improvement Plans (PSIPs) that cover the desired end states, and the path to progress from the current state to the desired end state by 2030.

SHARED VISION

Our vision is to deliver affordable, clean, reliable, and innovative energy services to our customers, creating meaningful benefits for Hawai'i's economy and environment, and making Hawai'i a leader in the nation's energy transformation. Hawai'i has the potential to become a national model for clean energy by not only achieving the highest

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COMMON OBJECTIVES

Common objectives across stakeholders drive the energy landscape of the future.

We share the Hawaiʻi Public Utilities Commission's commitment to lower, more stable electric bills; increased customer options; and reliable electric service in a rapidly changing environment.[3] In order to drive the transformation for Hawaiʻi, we have anchored our strategies in a set of common objectives.

These common objectives include:

1. **Affordable costs, reflecting the value provided to, and by, customers.** We will create sustainable value for our customers by providing affordable, stable and transparent costs. We will fairly compensate customers for the benefits they provide to the grid, while also fairly pricing the benefits customers derive from the grid.
2. **A clean energy future that protects our environment and reduces our reliance on imported fossil fuels.** Hawaiʻi is uniquely positioned to embrace the development of local renewable energy resources and increase our energy security. We will achieve a renewable portfolio that significantly exceeds the minimum standard of 40% by 2030.
3. **Expanded and diversified customer energy options.** We will serve all connected to the grid, including those with and without distributed generation (DG), through customized levels of grid services, electric power delivery and value-added products and service offerings.
4. **A safe, reliable and resilient electric system.** We will provide a level of reliability that supports our customers' quality of life. We are unwavering in our commitment to safety and reliability; these principles are the bedrock of any electrical system. Recognizing Hawaiʻi's remoteness and lack of interconnections, we must have an

[3] See "Commission's Inclinations on the Future of Hawaiʻi's Electric Utilities", Exhibit A attached to Decision and Order No 32052, filed on April 28, 2014, in Docket No. 2012-0036, at 3.

electric system resilient enough to support the continuous flow of energy to our communities through a wide variety of conditions and circumstances.

5. **A healthy Hawai‘i economy.** We will contribute to the health and diversity of Hawai‘i's economy for the benefit of all stakeholders.
6. **Innovation in energy technologies.** We will actively pursue new clean energy technologies in partnership with others to bring energy solutions to our customers.

APPROACH FOR THE PHYSICAL DESIGN OF THE ELECTRIC SYSTEM IN 2030

A transformation of the physical components of the grid (for example, generators, transmission and distribution infrastructure, non-transmission alternatives) is vital for the Companies to deliver on this vision. It requires both a clear understanding of the goals as well the ability to identify and implement a path from the current state to the desired end state.

The Companies recognize that the environment in which they operate is constantly changing. Continuous monitoring of market trends and changing circumstances are **critical for fact-based planning.** This **will require adjustment** of our **strategic and tactical plans within the planning horizon.**

To cope with the changing market trends, to support this transformation, to set goals and to set the path forward, the Companies have developed the Power Supply Improvement Plans in two steps:

A. **Step A: Define the desired end state for the physical design of the power system in 2030**

   This step was accomplished by developing a series of "clean sheet" hypothetical end states for 2030 that allowed the Companies to understand the broad ramifications associated with different futures, and choosing an end state that is in our view the best balance of objectives over the long term. The end state chosen is consistent with the underlying principles, recognizes the uniqueness of island grids, and promotes the State's clean energy policies.

B. **Step B: Define and validate a path to transform from the current state to the desired end state in 2030**

   This step was accomplished through application of utility industry accepted planning methods that take into account existing system conditions, technology commercial readiness, reliability and cost considerations. Chapters 3 through 7 and the appendices of this report provide the details of how this analysis was accomplished and the results of that analysis.

This approach enables our customers and other stakeholders to have a transparent view of the options considered and the potential tradeoffs[4] assessed during these analyses.

Step A: Clean-sheet analysis to define a desired end state and provide strategic direction

The goal of 'Step A'[5] was to provide high-level guidance for the physical design of the electric system in 2030, the end of the planning horizon considered in this PSIP. In order to ensure an un-biased and clean-sheet approach in defining the future physical design, the following guidelines were used in this step of the analysis:

- Forward-looking optimization focusing on 2030 as the single year.
- Using a fact-based and industry accepted set of assumptions and forecasts.
- Avoiding any pre-conceptions and not favoring any particular technology.
- Taking an ownership-agnostic view.
- Applying a spectrum of end state options to assess trade-offs.
- Applying a clean-sheet approach to define service reliability requirements.
- Evaluating the cost of the physical design options from an "all-in" societal perspective to consider the impact to Hawai'i versus any particular customer class (in this definition all-in societal costs included the total costs of DG-PV installation and maintenance in addition to all the utility-scale generation costs and T&D costs).[6]
- Using common objectives stated above to select the desired end state in 2030.

The goals of the approach were to assess the impact of various end states and to select one that the Companies should pursue as the desired target for the physical design in 2030.

Step B: Detailed and tactical production analytics to define and validate the path

In Step B., the focus shifted from goal setting to developing a detailed tactical and executable plan from today to the final vision in 2030, considering the feasibility, costs, risks, and activities required to support the transition. The operability of the system

[4] For instance one tradeoff might be low cost and another low cost volatility. Choosing the absolute lowest cost might result in high cost volatility. In a case like this we chose a path that resulted in a balance between low cost and low cost volatility.

[5] The strategic exercise under Step A has been performed on O'ahu, Maui and Hawai'i Island; Lana'i and Moloka'i were assessed separately within the detailed and tactical production analytics.

[6] Note that the evaluation under Step A was performed only for the clean-sheet analysis. The Preferred Plan and Financial analyses presented later in this report do not include customer-incurred costs related to installation and maintenance of customer-installed generation.

under various physical designs, as well as both normal and likely off-normal[7] circumstances, was tested and validated within an integrated planning and production simulation environment. Given the importance and complexity of this analysis, the Companies elected to create a unique, collaborative, and iterative modeling process powered by different models and participants. This process proved to be invaluable both in terms of validating key tactical and transitional solutions as well as providing a forum to test and refine concepts.

The detailed production simulations define the following annually from 2015 to 2030: existing generation portfolio, timing and characteristics of individual projects, retirements, implications of new tariffs (for example, DG 2.0)[8] and customer offerings (for example, Demand Response), system reliability, and operational requirements. This provides the ability to assemble and optimize the power system portfolio and grid design across time, consistent with our overall objectives to be cost-effective, to exceed the Renewable Portfolio Standard (RPS) goal, to reduce dependency on high-priced fossil fuels, to diversify and "green" the energy portfolio, and to establish a basis for implementing advanced technologies such as energy storage. **The analytical product is the Preferred Plan that is presented in Chapter 5 of this report.**

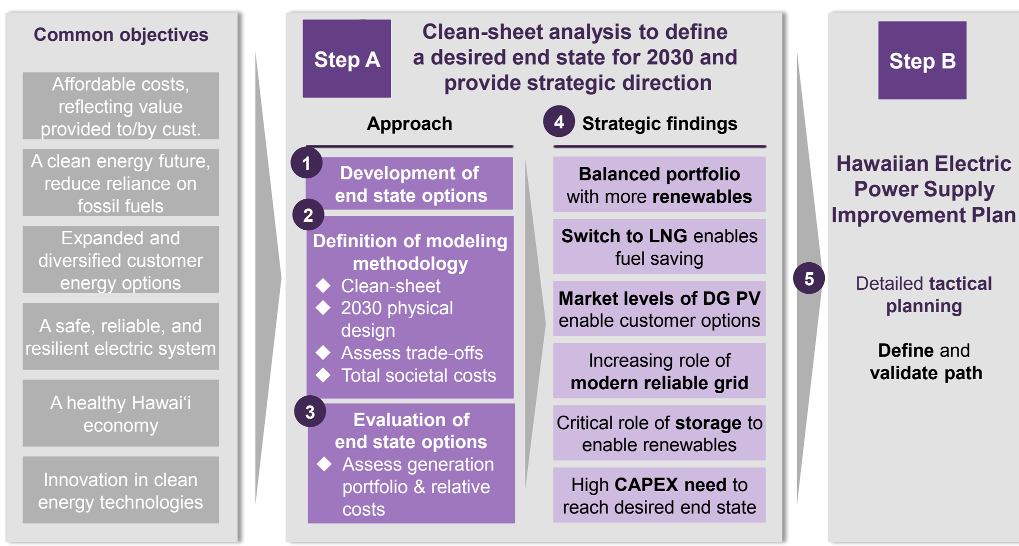

Figure 2-1. Approach to Define Desired Physical System Design 2030 End-State

The remainder of this chapter will focus on describing Step A in more detail.

7 Off-normal circumstances include likely events like trip of a large generating unit, trip of a heavily loaded transmission line, etc.

8 A generic term used to describe revised tariff structures governing export and non-export models, based on fair allocation of costs among distributed generation (DG) customers and traditional retail customers, and fair compensation of DG customers for energy provided to the grid.

Step A: Clean-Sheet Evaluation and Selection of the Desired End State

Development of End State Options

Five high-level physical design end state options were developed for the evaluation, reflecting a set of alternative futures with key trade-offs and differentiating factors, and fulfilling the necessary condition of achieving RPS targets and maintaining an operable system at affordable costs[9]. Five end state options were defined.

'Benchmark' end state: Describes the Companies' current liquid fuel-based portfolio trajectory with increasing DG-PV integration under the existing regulatory tariff and new utility-scale renewable projects that have already been submitted for approval to the PUC. It assumes LNG is not an accessible option for the islands.

'Least cost' end state: Describes the physical design assuming only the existing level of DG-PV integration, a cost-optimization of utility-scale renewable technologies firmed by LNG. This end state option optimizes the generation mix that results in the lowest overall societal cost level. As the levelized cost of DG-PV is expected to be higher than most other generation sources, DG-PV would not grow from today under the *'Least cost'* end state option.

'Balanced portfolio–DG 2.0' end state: Describes a generation portfolio that is a balance of system costs with increased renewables assuming a market driven DG-PV integration under a hypothetical "DG 2.0" rate structure (described in Chapter 6.), combined with an optimized utility-scale renewables portfolio firmed by LNG.

'Balanced portfolio–DG heavy' end state: Like *'Balanced portfolio–DG 2.0'*, this option seeks a balance of costs and renewables but allows for a much higher DG-PV integration compared with *'Balanced portfolio–DG 2.0'*. It assumes market driven DG-PV integration under the existing regulatory tariff, combined with an optimized, utility-scale renewable-portfolio firmed by LNG.

'100% Renewable' end state: Describes a generation portfolio to achieve 100% renewable share by 2030. It assumes market driven DG-PV integration under the existing tariff structure, maximum required utilization of other renewable resources on the islands, and the use of biofuel and biomass to fuel the necessary thermal generating resources for operability.

[9] " Affordable" includes both cost and cost volatility thereby including considerations such as fuel diversity.

Definition of Modeling Methodology for Step A

To quickly evaluate and have the flexibility to test each end state option at a high-level—the Companies developed a simplified hourly-based production model for 2030[10]. The model was ownership agnostic regarding generation resources and sought to calculate the total 'all-in societal' costs for the physical design (including generation costs and cost of the DG-PV paid by customers and through tax credits) and T&D costs.

High-Level Modeling Logic for Step A

The high level model for Step A is characterized by the following attributes:

- Hourly supply-demand model was built for 2030 for O'ahu, Maui and Hawai'i Island; Lana'i and Moloka'i were not in the scope of the analysis performed under Step A.
- Levelized cost of energy and technology attributes assessed for over 15 technologies (DG-PV, utility-scale PV, onshore-wind, offshore-wind, ocean thermal, ocean wave, run-of-river hydro, geothermal, waste-to-energy, biomass, coal, various LNG technologies, oil-based steam, biofuel, energy storage).
- DG-PV installed capacities for 2030 were taken as an input into the model, developed by the Companies and used in the DGIP and PSIP process.
- High level estimates for reliability requirements were linked to capacities for DG-PV, utility-scale PV and wind for day-time and also linked to wind only for night-time. (Detailed tactical planning in Step B calculates with more precision system security requirements that differ by hour based on the generation portfolio output.)
- Demand was covered for every hour of the year starting with DG-PV considering its hourly load shape, followed by the various technologies based on their cost economics and resource constraints.
- Optimization minimizes aggregated costs across renewable generation, conventional generation, storage costs, curtailment and ancillary services.
- Overall installed firm capacities required were 30% above annual system peak-load
- The assessment did not consider most existing configurations, except that all existing contracts were honored until their expiration.
- The model assumed any and all configurations were operable and reliable.
- All the assumptions used in the model were aligned and consistent with subsequent, more detailed modeling efforts described in Chapters 3 through 7.
- Estimates on Transmission & Distribution (T&D) costs have also been added to each of the end state options. The T&D costs encompassed transmission, distribution, smart

[10] This model considered high-level estimates on reliability constraints, did not consider most existing configurations, except that all existing contracts were honored until their expiration and assumed any and all configurations were operable and reliable.

grid and system operations investments. These costs were derived for each resulting end state option by assessing the expected location of generation assets on the system.

Key input parameters that were included in the strategic model to assess tradeoffs:

- **Demand parameters:** All relevant demand information for 2030, such as hourly demand curves for 2030, including the impact of gross demand and energy efficiency measures, hourly demand response adjustment factors, network losses, and DG-PV integration rates.
- **Supply parameters:** All relevant supply information for 2030, such as technology readiness, levelized cost of energy capital and operating costs per technology for 2030 based on National Renewable Energy Laboratories (NREL) forecasts[11] and Energy Information Administration (EIA) adjustment factors[12], fuel price forecasts, resource constraints per technology, hourly capacity factors per renewable technologies, assumed lifetime of assets, grid integration costs, forecast on DG-PV installed capacities.
- **System security requirements:** Annual reserve margin requirement, day-time and night-time regulating and contingency reserves.
- **Other:** Inflation, cost of capital.

Parameters that were not included in the strategic model (Step A) but were included in the detailed tactical PSIP analytics and modeling (Step B):

- **Demand parameters:** All relevant demand information from 2015 to 2030, sub-hourly information.
- **Supply parameters:** All relevant supply information from 2015 to 2030, unit level technology information, maintenance schedules per unit, existing generation fleet, existing contractual capital cost and energy cost conditions, contractual dispatch requirements and contract duration, differentiation of costs depending on the year of building assets, retirements, minimum load requirement per unit, various type of storage technologies, retirement schedules.
- **System security requirements:** Regulating and contingency reserves on hourly basis; full range of system security requirements in line with the Companies written policies, use of demand response programs for ancillary services.
- **Other:** Avoided cost calculation for Hawai‘i Island PPAs.

[11] National Renewable Energy Laboratories: Cost and performance data for power generation technologies (2012).

[12] Energy Information Administration: Updated capital cost estimates for utility-scale electricity generating plants (2013).

Key inputs of the model were the following:

- The expected levelized cost of various generation technologies assuming the generation mix is built by 2030
- Resource constraints and technological attributes of alternative technologies
- Service reliability requirements like contingency reserve requirement, regulating reserve requirement, and reserve margins
- Estimated T&D costs to enable interconnection and ensure safe and reliable service

The results of the assessment for Step A were optimized physical design portfolios by each end state option and island considering the costs and attributes of the different end states. In addition, transmission and distribution upgrade costs to integrate additional generation units were estimated and included to result in a total cost by end state option.

The same assumptions were used in Step A and Step B. The assumptions are summarized in Appendix F, and the major assumptions are presented and discussed in Chapter 4.

Evaluation of end state options across common objectives and selection of desired end state

The evaluation of the five high-level physical design end state options across the common objectives resulted in the selection of *'Balanced portfolio–DG 2.0'* as the desired 2030 physical design.

This option would provide for a robust and diversified renewable portfolio mix that will significantly exceed the 2030 RPS, reduce Hawai'i's dependence on oil, and support a clean energy economy. Market driven DG-PV provides options for our customers. While 'all-in societal costs' were higher than the least cost option, DG 2.0's revised tariff structure would create an equitable rate structure to mitigate the DG cost impact to full service customers who are expected to be the majority of our customer base through 2030.

While the other four end state options were optimized to certain objectives, they were not selected due to other tradeoffs:

- **'Benchmark':** Oil-based fuels make this option costly and is the least favorable for a clean energy future due to highest level of emissions and continued dependence on imported fossil fuels.
- **'Least cost':** This option proves that switching from oil to LNG and higher levels of renewables is favorable for reducing costs; however, due to the limitations on the option for customers to install DG-PV, it is not supportive of expanding and diversified customer energy options.
- **'Balanced Portfolio–DG heavy':** Driven by higher DG-PV prevalence, the end state all-in societal generation and T&D costs are higher than *'Least cost'* and *'Balanced*

portfolio–DG 2.0'. It also puts pressure on the reliability of the system given the high level of variable renewables.

- **'100% renewable':** This is achievable but it also has the highest cost, driven by potential resource constraints on lower cost resources, the required energy storage systems to integrate renewables and maintain an operable system and high cost of biofuels compared to other resources that are required to achieve 100% renewable generation. It also puts pressure on the reliability of the system given the high level of variable renewables.

Strategic findings from the selected desired end state ('Balanced portfolio–DG 2.0')

The above described exercise resulted in the following overall strategic findings related to the desired *'Balanced portfolio–DG 2.0'* physical design of the electric system in 2030:

- The aggregated Renewable Portfolio Standard (RPS) will substantially exceed the RPS mandate of 40% by 2030.
- A balanced portfolio of variable and dispatchable renewables in concert with thermal units offers the most value to customers.
- Converted and new LNG fired thermal units provide critical, efficient and flexible energy resources, ensure the operability and reliability of the grid, enable unit retirements, and can work in combination with variable renewable resources.
- LNG will enable significant fuel saving versus other liquid fuels.
- A combination of distributed and utility-scale resources contribute to the portfolio.
- Under the hypothetical new DG 2.0 tariff structure, aggregated DG-PV capacities across all Companies expected to grow rapidly from the current ~330 MW up to ~910 MW corresponding to ~15% of the total generation (HECO ~650 MW, MECO ~135 MW, and HELCO ~115 MW).
- Energy storage will be a key enabling technology for higher renewables while ensuring reliability and resiliency of the system.

STRATEGIC DIRECTION FOR THE DEVELOPMENT OF COMPREHENSIVE TACTICAL MODELS AND PLANS IN STEP B

The objective in Step A was to define the target clean-sheet end state for the physical design in 2030 for the Companies and derive strategic findings and strategic initiatives for future development. In order to realize the desired end state the Companies see the following major strategic initiatives:

- Increase the integration of utility-scale and DG renewable energy resources to exceed the 2030 RPS goal and provide customers with options;
- Diversify the fuel mix to provide lower-cost fuel options and energy service reliability;
- Prepare for LNG and pursue an optimized retirement plan for older oil-fired generation;
- Utilize energy storage to manage increasing integration of variable renewables;
- Expand demand response programs to allow increasing integration of renewables and broadening customer participation;
- Modernize the electric grid to provide greater reliability, minimize costs associated with operating the grid, and enable more renewables and customer energy-management options.

Guided by the strategic findings and directions outlined above, the next step was to translate the selection of 'Balanced Portfolio–DG 2.0' into a detailed tactical plan for each island to transform the existing physical design into the desired end state.

The remainder of this PSIP will further explain Step B and Preferred Plan to achieve the desired physical design, consistent with the above findings.

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3. Current Generation Resources

The Hawaiian Electric Companies provide generation on five islands—O‘ahu, Maui, Moloka‘i, Lana‘i, and Hawai‘i Island—with three utilities and five grids. This accounts for about 90% of all the generation requirements for the entire state of Hawai‘i.

Hawai‘i Electric Light serves 81,000 customers on Hawai‘i Island with 287 MW (net) generation.

RENEWABLE RESOURCES

Within the three utilities, the renewable generation varies widely. As of December 31, 2013, Table 3-1 demonstrates that the Hawaiian Electric Companies are far exceeding the Renewable Portfolio Standard (RPS) requirement of 15% by 2015.

Utility	Renewable Portfolio Standard
Hawaiian Electric	28.6%
Maui Electric	44.4%
Hawai‘i Electric Light	60.7%
Consolidated	34.4%

Table 3-1. 2013 Renewable Portfolio Standard Percentages

Renewable Generation

The Companies have a number of clean energy generation units across the service area. Figure 3-1 points outs these units and the island where they are sited.

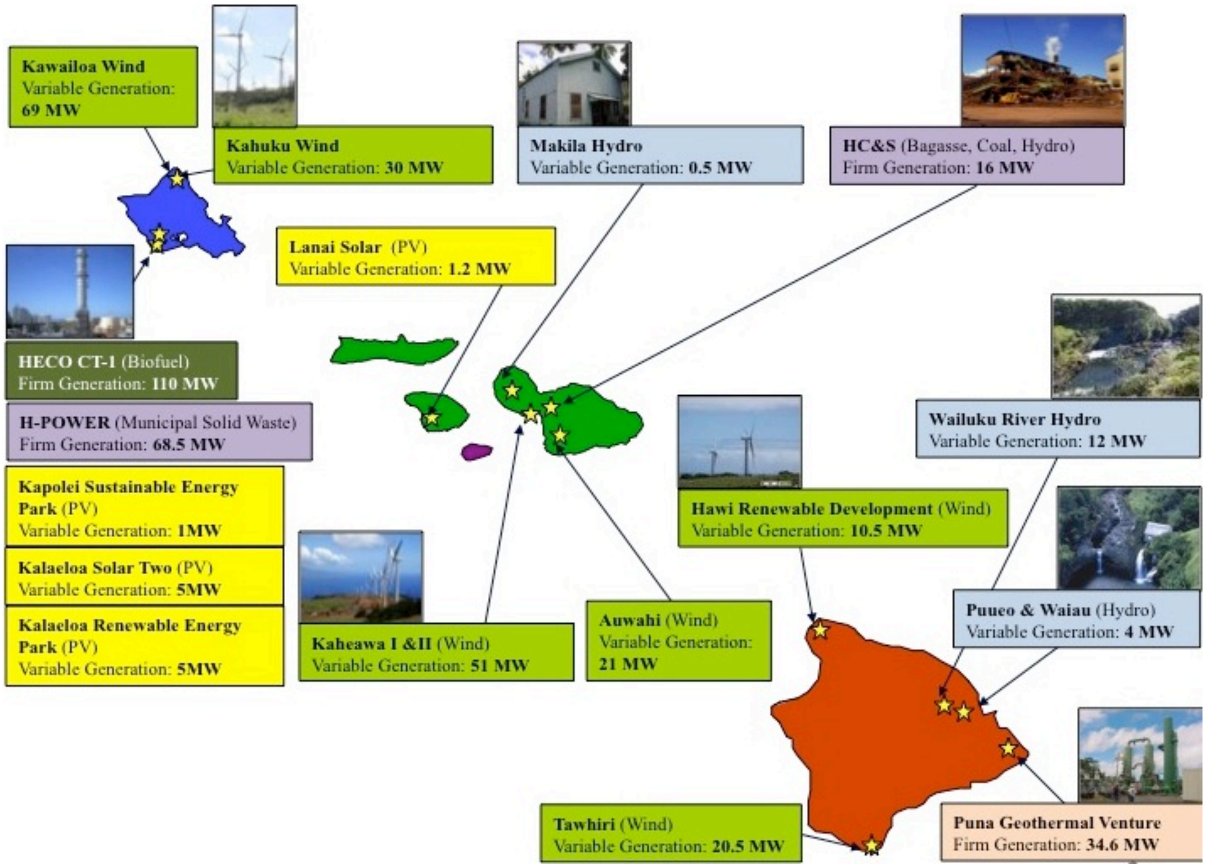

Figure 3-1. Current Clean Energy Resources

In total, the Companies have 131.2 MW of variable clean generation and 210 MW of firm clean generation.

Renewable Generation Resources

The renewable energy generated by all three operating utilities is comprised of a number of resources. In total, we have attained an RPS of 34.4%.

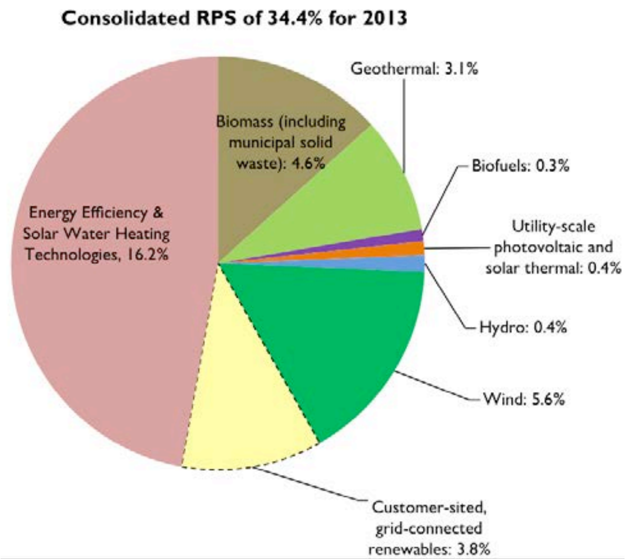

Figure 3-2. Consolidated RPS of 34.4% for 2013

Photovoltaic Installations

The last ten years have witnessed an explosion in PV generation, mostly from individual distributed generation. By the last quarter of 2013, the amount of megawatts generated has grown almost 170 times greater as compared to only seven years earlier (in 2005).

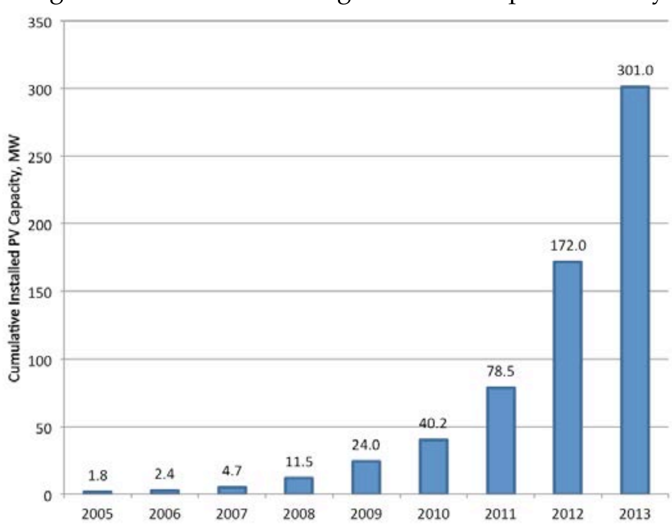

Figure 3-3. Photovoltaic Generation Growth: 2005 through 2013

HAWAI'I ELECTRIC LIGHT GENERATION

Hawai'i Electric Light currently owns and operates 24 firm generating units, totaling about 182 MW (net), at five generating stations and four distributed generation sites. Five steam units fueled with No. 6 fuel oil (MSFO) are located at the Shipman, Hill, and Puna Generating Stations. Ten diesel engine generators fueled with diesel fuel are located at the Waimea, Kanoelehua, and Keahole Generating Stations. Hawai'i Electric Light's five combustion turbines (CT) fueled with diesel fuel are located at the Kanoelehua, Keahole, and Puna Generating Stations. The Keahole CTs are configured to operate in combined cycle with heat recovery steam generators and a steam turbine. Four distributed generation diesel engines fueled with diesel fuel are located (one each) at the Panaewa, Ouli, Punalu'u, and Kapua substations.

Hawai'i Electric Light also currently owns and operates two run-of-river hydro facilities at Puueo and Waiau.

There are two independent power producers that provide firm capacity power to the Hawai'i Electric Light grid. One is a combined-cycle power plant owned and operated by Hamakua Energy Partners LP (HEP). The other is a geothermal power plant owned and operated by Puna Geothermal Venture (PGV). In addition to the two firm capacity independent power producers, there are three independent power producers that furnish a significant amount of power to the Hawai'i Electric Light grid on a non-firm, variable basis: Tawhiri wind (20.5 MW), Hawi Renewable Development wind (10.5 MW), and Wailuku River (run-of-river) Hydro (12.1 MW).

Hawai'i Electric Light has a power purchase agreement with Hu Honua Bioenergy, a 20.5 MW biomass facility scheduled to come online in 2015.

Hawai'i Electric Light Utility-Owned Firm Generation

Hawai'i Electric Light generates 194.85 MW of firm generation from its utility-owned units.

Unit	Delivery Type	Fuel	Top Load Rating MW	Reserve Rating MW	Start Date
Hill 5 (Kanoelehua)	Baseload	MSFO	13.5	13.5	1965
Hill 6 (Kanoelehua)	Baseload	MSFO	20.2	20.2	1974
Kanoelehua 11	Peaking	Diesel	2.0	2.0	1962
Kanoelehua 15	Peaking	Diesel	2.5	2.75	1972
Kanoelehua 16	Peaking	Diesel	2.5	2.75	1972
Kanoelehua 17	Peaking	Diesel	2.5	2.75	1973
Kanoelehua CT-1	Peaking	Diesel	11.5	11.5	1962
Kapua D-27	Peaking	Diesel	1.0	1.0	1998
Keahole 21	Peaking	Diesel	2.5	2.75	1984
Keahole 22	Peaking	Diesel	2.5	2.75	1984
Keahole 23	Peaking	Diesel	2.5	2.75	1988
Keahole CT-2	Intermediate	Diesel	13.8	13.8	1989
Keahole CT-4/CT-5/ST-7	Intermediate	Diesel	56.25	56.25	2004
Ouli D-25	Peaking	Diesel	1.0	1.0	1998
Paneawa D-24	Peaking	Diesel	1.0	1.0	1998
Puna	Baseload	MSFO	15.7	15.7	1970
Puna CT-3	Intermediate	Diesel	21.0	21.0	1992
Punalu'u D-26	Peaking	Diesel	1.0	1.0	1998
Shipman 3	Deactivated	MSFO	7.1	7.1	1955
Shipman 4	Deactivated	MSFO	7.3	7.3	1958
Waimea 12	Peaking	Diesel	2.5	2.75	1970
Waimea 13	Peaking	Diesel	2.5	2.75	1972
Waimea 14	Peaking	Diesel	2.5	2.75	1972
Totals	—	—	194.85	197.1	—

Table 3-2. Hawai'i Electric Light Utility-Owned Firm Generation (Net to System)

Hawaiʻi Electric Light Renewable Generation

Hawaiʻi Electric Light's renewable energy already exceeds the 2030 RPS requirement of 40%, which doesn't include energy efficiency measures or solar water heating.

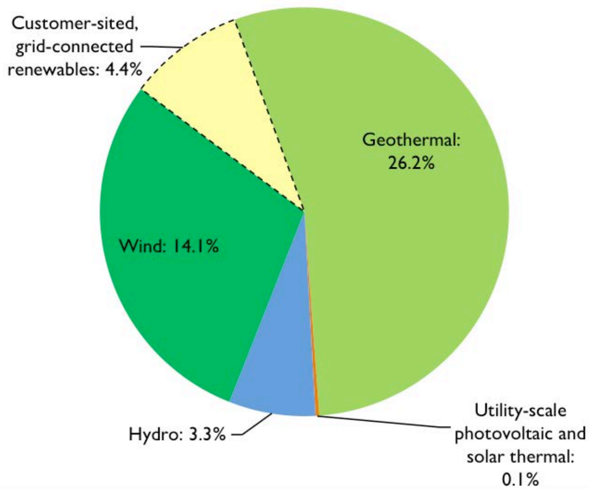

Figure 3-4. 2013 Hawaiʻi Electric Light RPS Percent

Hawaiʻi Electric Light generates over 103 MW of power from renewable sources.

Unit	Energy	Net MW	Delivery Type
Puʻueo No. 1	Hydro	2.60	Variable
Puʻueo No. 2	Hydro	0.75	Variable
Waiau No. 1	Hydro	0.75	Variable
Waiau No. 2	Hydro	0.35	Variable
Puna Geothermal Venture	Geothermal	34.60	Firm
Tawhiri Power LLC	Wind	20.50	Variable
Hawi Renewable Development	Wind	10.50	Variable
Hu Honua Bioenergy (online 2015)	Biomass	21.50	Firm
Wailuku River Hydroelectric LP	Hydro	12.10	Variable
Totals	—	*103.65*	—

Table 3-3. Hawaiʻi Electric Light Renewable Energy Resources

HAWAI'I ELECTRIC LIGHT DISTRIBUTED GENERATION

Distributed generation, mostly photovoltaics, are being installed by our customers on many of our distribution feeders. The growth of PV systems has been exponential on all of our major islands. All three operating utilities are in the Solar Electric Power Association's top 10 PV per capita. The accompanying maps show just how "distributed" the distributed generation on the island are, and the transmission and distribution challenges this presents.

Figure 3-5 shows the distributed generation areas on Hawai'i Island.

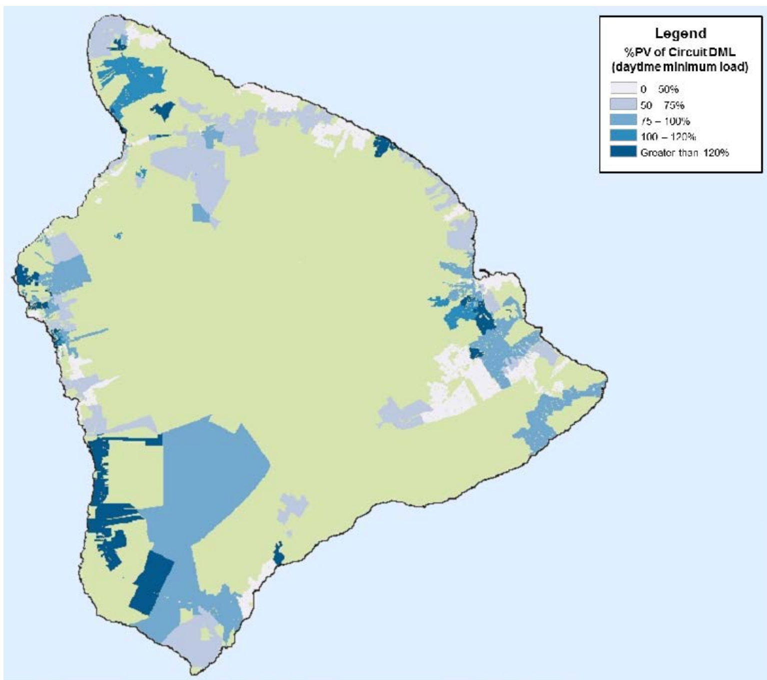

Figure 3-5. Hawai'i Island Distributed Generation Map

EMERGING RENEWABLE GENERATION TECHNOLOGIES

The Hawaiian Electric Companies considered many different renewable energy resources in our analyses for creating the PSIPs. Some of these renewable resources are currently commercially available, while others are emerging. Rather than consider the best available projections for these emerging technologies, we have based our PSIPs on readily available renewable energy resources. These include:

- Utility-scale simple-cycle combustion turbines
- Utility-scale combined-cycle combustion turbine and steam generator combinations
- Biomass and waste-fueled steam generation
- Internal combustion engine generation
- Geothermal generation
- Onshore utility-scale wind generation
- Utility-scale and small-scale solar photovoltaic generation
- Run-of-river hydroelectric
- Pumped storage hydroelectric

Several other commercially available generation technologies were also not considered appropriate for inclusion in our PSIPs (such as nuclear energy and storage hydroelectric).

Determining Commercial Readiness

The Australian Renewable Energy Agency (ARENA) developed a Commercial Readiness Index (CRI) and released it in February 2014. We used the CRI to evaluate emerging generation options for the PSIPs because we found the CRI provided practical, objective and actionable guidance.

The CRI rates the commercial readiness level of a particular technology on a scale from 1-lowest level of readiness to 6-bankable. (See Appendix H: Emerging Renewable Technologies for more details on the rating scale.) In general, the CRI finds technologies commercially ready when:

- The technology has been implemented in a commercial setting and meets its intended need.
- The technology has been sited, permitted, built, and operated at full scale; and these challenges are well understood.

- The electricity industry, in general, accepts the performance and cost characteristics of the technology.
- Well capitalized engineering procurement construction vendors willingly provide cost and performance guarantees around an asset that uses the technology.
- A service, repair and parts system exists to support the technology.
- Financial institutions willingly accept the performance risk when underwriting technology projects.

We only considered commercially ready technologies (CRI level 5 or 6) in our PSIP modeling analyses.

Technologies Not Commercially Ready

A number of emerging—although not commercially ready— generation technologies have been proposed for our Hawaiʻi power grids, including ocean wave, tidal power, ocean thermal energy storage (OTEC), and concentrated solar thermal power (CSP). See Appendix H: Emerging Renewable Technologies for details on these technologies.

Two of these technologies hold much promise.

Ocean Thermal Energy Conversion (OTEC). Hawaiʻi is a pioneer in OTEC research, having demonstrated the first successful OTEC project on Hawaiʻi 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. Hawaiian Electric is currently in power purchase negotiations with OTEC International (OTECI) for an OTEC facility to provide power to the island of Oʻahu. In order to prove commercial readiness, OTECI would be required to complete and operate a 1 MW demonstration plant for an agreed period of time, and if successful, conduct additional incremental testing of the full-scale facility prior to full operation.

Wave/Tidal Power. Successful demonstration tidal and wave power projects have been implemented in several locations, including Hawaiʻi. 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 challenged. Thus, tidal and wave power generation remains not commercially ready.

Technology Planning Assumptions versus Policy Considerations

While we limited our PSIPs plan to currently available technologies, we remain open to including future renewable technologies in our generation resource mix—when they become commercially available. We also remain open to installing pilot and demonstration projects for these and any other viable emerging renewable technology.

We welcome responses to our procurement Request for Proposals (RFPs) that include emerging technologies, and pledge to evaluate these responses on their merits. Evaluation factors can include:

- Commercial readiness of the proposed technology.
- Community acceptance of the project proposed.
- Viability of its siting, licensing, permitting, and construction.
- Realistic site-specific costs.

Factors deemed relevant to the specific project and technology will also be included in our evaluation.

4. Major Planning Assumptions

The Hawaiian Electric Companies created this PSIP based, in parts, on a realization of the current state of the electric systems in Hawai‘i, forecast conditions, and reasonable assumptions regarding technology readiness, availability, performance, applicability, and costs. As a result, this plan presents a reasonable and viable path into the future for the evolution of our power systems. We have attempted to document and be fully transparent about the assumptions and methodologies utilized to develop this plan. We recognize, however, that over time these forecasts and assumptions may or may not prove to be accurate or representative, and that the plan would need to be updated to reflect changes. As we move forward, we will continually evaluate the impacts of any changes to our material assumptions, seek to improve the planning methodologies, and evaluate and revise the plan to best meet the needs of our customers.

The PSIP analyses were conducted using production simulation planning tools that employ industry-accepted algorithms and methodologies (see Appendix C). These tools require the utility planner to develop a set of assumptions and data that allow for consistent analysis of various scenarios of interest. Figure 4-1 is a generalization of the categories of input assumptions and data that is required for production simulation analysis.

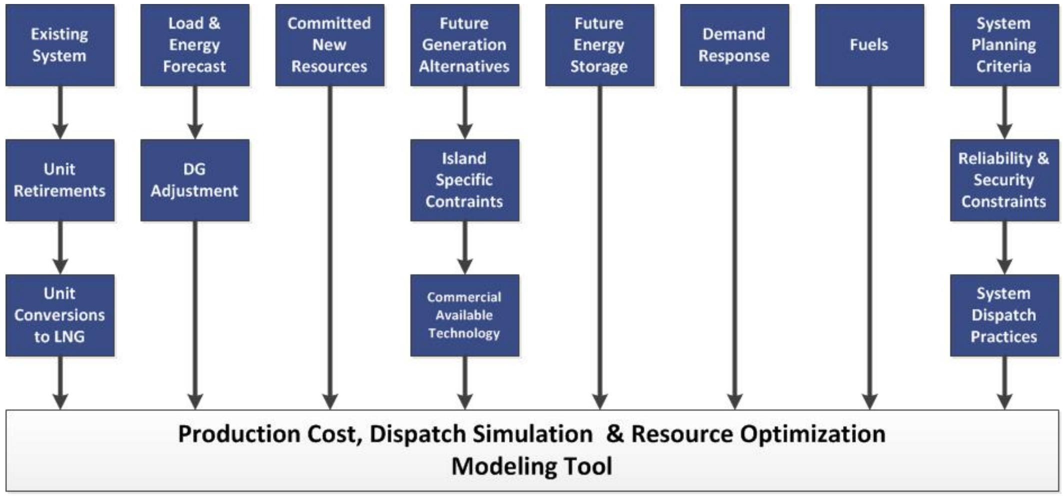

Figure 4-1. PSIP Production Simulation Model Input Hierarchy

This Chapter 4 summarizes the assumptions and data use to develop the scenarios and the results presented in this PSIP. Appendix F: Modeling Assumptions Data contains more detailed quantitative assumptions and data used in the analyses.

EXISTING POWER SYSTEMS

The starting point for a long-range planning analysis is the existing state of the Companies' individual power systems.

General System Descriptions

Hawaiian Electric: As of the end of 2013, the existing Hawaiian Electric power system on O‘ahu consists of 1,298 MW of utility-owned generating capacity, 457 MW of firm Independent Power Producer (IPP) capacity, and 110 MW of variable renewable IPP capacity. There was approximately 167 MW of installed net energy metering capacity from renewable energy technologies (mainly photovoltaic) and 10 MW of installed feed-in tariff (FIT) capacity. Hawaiian Electric operates 215 circuit miles of overhead 138,000 volt (also expressed as “138 kilovolts” or “138 kV”) transmission lines and 8 miles of underground transmission lines, 537 circuit miles of overhead and underground 46 kV sub-transmission lines, 2,231 circuit miles of overhead and underground distribution lines (nominal distribution voltages of 4.16 kV, 12.47 kV and 25 kV), 21 transmission substations and 131 distribution substations.

Maui Electric: As of the end of 2013, the existing Maui Electric power system on Maui consists of 243 MW of utility-owned generating capacity, 16 MW of firm IPP capacity, and 72.5 MW of variable renewable IPP capacity. Maui Electric’s system on Lana‘i has

10.23 MW of company-owned thermal generation, and 1.2 MW of variable IPP capacity. Maui Electric's system on Molokaʻi has 12.01 MW of utility owned capacity. There was approximately 35 MW of installed net energy metering capacity, and 2 MW of feed-in tariff capacity within Maui Electric's service area. Maui Electric operates 250 miles of 69 kV and 23 kV transmission lines and a 34.5 kV on Molokaʻi, eight transmission-level substations, 71 distribution substations, and 1,520 miles of 12.47 kV, 7.2 kV, 4.16 kV, and 2.4 kV distribution lines.

Hawaiʻi Electric Light: As of the end of 2013, the existing Hawaiʻi Electric Light power system on Hawaiʻi Island consists of 195 MW of utility-owned thermal generating capacity, 94.6 MW of firm IPP capacity, 4.5 MW of utility-owned variable generation and 43.1 MW of variable renewable IPP capacity. There was approximately 33 MW of installed net energy metering, and 1 MW of feed-in tariff capacity. Hawaiʻi Electric Light operates 641 miles of 69 kV transmission lines, 22 transmission-level substations, 78 distribution substations, and 4,080 miles of 13.2 kV distribution lines.

Table 4-1 contrasts the nature of each of the three operating systems in terms of customer density expressed in customers per mile of distribution circuit.

	Number of Customers (12/31/13)	Distribution Circuit Miles	Customers Per Mile of Distribution Line
Hawaiian Electric	299,528	2,231	134.3
Maui Electric	69,577	1,520	45.8
Hawaiʻi Electric Light	82,637	4,080	20.3

Table 4-1. Customers per Mile of Distribution Line by Operating Company

Existing Generation Units & Retirement Dates

The list of Company's existing units is provided in Chapter 3. The retirement dates of the Company's existing generating units, if applicable, are provided in the discussion of the Preferred Plan in Chapter 5.

Liquefied Natural Gas (LNG) Unit Conversion

In the preferred plan, it was assumed that certain of the Companies' units would be converted to LNG during the planning period.

Hawaiian Electric

- Kahe 1-6 converted to use LNG beginning in 2017
- Waiau 5-10 converted to use LNG beginning in 2017
- Kalaeloa (IPP) converted to use LNG beginning in 2017 (at Company expense).

Maui Electric

- Ma'alea 14, 15, 16, 17, 19 converted to use LNG beginning in 2017
- Waena internal combustion engine (ICE) units (relocated from South Maui) converted to use LNG beginning in 2024.
- Waena Internal Combustion Engine (ICE) units relocated from South Maui and converted to use LNG beginning in 2024.

Hawai'i Electric Light

- Puna CT3, Keahole Combined Cycle Units (CT4, CT5) converted in 2017
- Hamakua Energy Partners (HEP) (IPP) converted (at Company expense) to use LNG in 2018.

Existing Independent Power Producer (IPP) Contract Assumptions

During the planning period, assumptions were made regarding how certain IPP contracts would be renewed, cancelled, or renegotiated during the planning period. Existing IPP contracts expiring within the study period were assumed to continue past the expiration date of the current contract, and switch to the modeled resource pricing at the time of expiration as shown in Appendix F (on January 1 of the next year for modeling purposes). These IPPs were assumed to retain present curtailment priority and methodology. These are planning assumptions only; the dispositions of the Companies' contracts with IPPs are subject to the terms of the existing PPAs, and/or the ability of the third parties and the Company to reach mutual agreement (subject to the Commission's approval) on pricing, terms, and conditions applicable beyond the expirations of the current PPAs.

Hawaiian Electric

- The Kalaeloa Energy Partners PPA was assumed to be extended at the end of its contract term (May 23, 2016) for six years, to 2022. At its expiration in 2022, the PPA was assumed to the renegotiated, subject to competitive procurement, and extended past the PSIP planning period.
- The AES Hawaiʻi PPA was assumed to be renegotiated, subject to competitive procurement, at the end of its contract term (September 1, 2022), and extended past the end of the PSIP planning period, at its full 180 MW capacity, but with a mix of 50% coal and 50% biomass for fuel.

Maui Electric

- The HC&S PPA was assumed terminated on 12/31/18 based on expected efforts to negotiate and extend the current agreement, subject to Commission approval.
- Kaheawa Wind Power (KWP) was assumed to continue at current nameplate capacity beyond the end of its current contract in 2026, but will be paid according to pricing identified in Appendix F.
- Makila Hydro will continue at current nameplate capacity beyond the end of its current contract in 2026. For purposes of this report, the Makila Hydro payment, from January 2015 to December 2026, is assumed to be fixed at Maui Electric's August 2014 Avoided Cost per Docket No. 7310. For the period of 2027 to 2030 Makila Hydro will be paid according to pricing identified in the Appendix F.

Hawaiʻi Electric Light

- Conversion of HEP to LNG in 2018.
- Hawi Renewable Development (HRD) – was assumed to continue at current name plate capacity beyond the end of its current contract in 2021, but will be paid according to pricing identified in Appendix F.
- Wailuku River Hydro – was assumed to continue at current nameplate capacity beyond the end of its current contract in 2023, but will be paid according to pricing identified in Appendix F.
- Tawhiri - was assumed to continue at current nameplate capacity beyond the end of its current contract in 2027, but will be paid according to pricing identified in Appendix F.
- Puna Geothermal Ventures (PGV) - was assumed to continue at current name plate capacity beyond the end of its current contract in 2027, but will be paid according to pricing identified in Appendix F.

Committed New Resources

The Companies have made certain commitments regarding new resource additions. Several of these resource commitments have received Commission approval. Others are the still subject to Commission review and approval.

Hawaiian Electric

The following future generating resources are considered to be committed for planning purposes, and are therefore included in the Base Plan and Preferred Plan for Hawaiian Electric:

- Waiver Projects: 244 MW of multiple IPP-developed solar PV projects that are being negotiated pursuant to the waivers from the framework for competitive bidding in Dockets Nos. 2013-0156 and 2013-0381. Each separate PPA for the waiver projects will require Commission approval. These projects will contribute to the Companies' RPS requirements. These projects are assumed to enter service by the end of 2016.
- Na Pua Makina Wind: 24 MW IPP-owned wind energy generation facility project near the community of Kahuku on the north shore of O'ahu. This project is assumed to enter service by the end of 2016. This project will contribute to the Companies' RPS requirements. Approval of the PPA for this project is pending in Docket No. 2012-0423.
- Mililani South Solar: 20 MW IPP-owned utility-scale solar PV project facility near Mililani, O'ahu. This project is assumed to enter service by the end of 2016. This project will contribute to the Companies' RPS requirements. Approval of the PPA for this project is pending in Docket No. 2014-0077.
- Kahe Solar PV: 11.5 MW utility-scale solar PV project that is being developed by the Hawaiian Electric at the Kahe generating station site. This project is assumed to enter service by the end of 2016. This project will contribute to the Companies' RPS requirements. Approval of this project is pending in Docket No. 2013-0360.
- Schofield Generating Station: 50 MW total, consisting of six separate reciprocating engines each having a generating capacity of 8.4 MW. Schofield Generating Station will utilize at least 50% biodiesel and will contribute to the Companies' RPS requirements. Approval of this project is pending in Docket No. 2014-0113. This project is assumed to enter service during 2017.

Maui Electric

There are no committed resources for Maui Electric at the present time. It is assumed that Maui Electric will issue an RFP in 2015 for new generation to become available in 2019.

Hawai'i Electric Light

The following future generating resources are considered to be committed and are therefore included in the base plan for Hawai'i Electric Light:

- Hu Honua: 21.5 MW biomass IPP-owned project at Pepeekeo, Hawai'i Island. The PPA for this project was approved by the Commission in Docket 2012-0212, pursuant to Order No. 31758, issued on December 20, 2013. This project will contribute to the Companies' RPS requirements. This project is assumed to enter service in 2015.
- Geothermal RFP: Hawai'i Electric Light has to committed to modeling 25 and 50 MW of new IPP-owned geothermal projects and to issue a Request for Best and Final Offers for at least 25 MW. Pursuant to Commission Order in Docket No. 2012-0092, the Request for Best and Final Offers shall be filed no later than September 25, 2014 for Commission review and approval.

CAPACITY VALUE OF VARIABLE GENERATION AND DEMAND RESPONSE

Wind and solar are variable generating resources. Therefore, determining their capacity value (that is, the variable resource's ability to replace firm generation) with a high level of confidence is a considerable challenge. However this determination is a critical exercise in order to ensure that customer demand is met and system reliability is maintained.

Capacity Value of Wind Generation

The determination of when additional firm capacity is needed is, in part, based on the application of Hawaiian Electric's generating system reliability guideline, which is 4.5 years per day loss of load probability (LOLP). The capacity value of existing and future wind resources is determined through an LOLP analysis that incorporates this guideline. The wind resources' contribution to serving load is reflected in the LOLP calculations. Accordingly, wind resources' contributions to capacity are dependent upon the composition and assumptions in each plan. Future LOLP analyses that incorporate additional wind resources may affect the actual capacity value of existing wind resources.

Hawaiian Electric

Based on historical 2013 O'ahu wind data, the aggregate capacity value of the two existing wind farms (30 MW Kahuku Wind and 69 MW Kawailoa Wind) determined through an LOLP analysis is approximately 10 MW, or about 10% of the nameplate value of the existing wind resources.

Maui Electric

The aggregate value of the three existing wind farms (20 MW Kaheawa Wind Power I, 21 MW Kaheawa Wind Power II, 21 MW Auwahi Wind Energy) contribution to capacity planning is 2 MW based on historical examination of available wind capacity during the peak period hours to derive an amount which is probable during that period.

The capacity value of future wind farms for PSIP modeling purposes is 3% of the nameplate value of the facility to be added.

Hawai‘i Electric Light

The aggregate capacity planning value of the two existing wind farms (20.5 MW Tawhiri wind farm and 10.56 MW Hawi Renewable Development wind farm) is 3.1 MW. This is based on an historical examination of available wind capacity during the peak period hours to derive an amount that is probable during the historical period. The capacity value of the hydro facilities was 0.7 MW using the same methodology used to determine the capacity value of wind.

The capacity value of future wind farms for PSIP modeling purposes is 10% of the nameplate value of the facility to be added.

Capacity Value of Solar Generation

The capacity value of existing and future utility-scale and rooftop PV is 0, using the same capacity valuation methodology used for the wind and hydro resources. This result is driven by the fact that variable PV does not produce during the utility’s peak periods (that is, evenings). It is the utility’s net peak demand that determines the need for additional capacity.

Capacity Value of Demand Response

The estimated megawatt potential from the Residential and Small Business Direct Load Control Program, Commercial and Industrial Direct Load Control Program, Customer Firm Generation Program, and Time-of-use Programs are included in PISP capacity planning based on the *Integrated Demand Response Portfolio Plan*.[13]

[13] The Companies filed its *Integrated Demand Response Portfolio Plan* (IDRPP) with the Commission on July 28, 2014.

LOAD AND ENERGY PROJECTION METHODOLOGY

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

The methodology for arriving at the net peak demand and energy requirements to be served by the Company begins with the identification of key assumptions such as the economic outlook, analysis of existing and proposed large customer loads, and impacts of customer-sited technologies such as energy efficiency measures and customer-owned distributed generation. Impacts from emerging technologies such as electric vehicles are also considered as they can significantly impact sales in the future.

Sales Forecast

The underlying economic sales forecast is derived first by using econometric methods and historical sales data excluding impacts from energy efficiency measures or customer-sited distributed generation ("underlying economic sales forecast"). Estimates of impacts from energy efficiency measures, customer-sited distributed generation through the Company's tariffed programs and electric vehicles (referred to as "layers") were then used to adjust the underlying economic sales forecast to arrive at the final sales forecast.

Peak Forecast

The Hawaiian Electric peak forecast is derived using Electric Power Research Institute's Hourly Electric Load Model (HELM). Maui and Hawai'i Electric Light use Itron Inc.'s proprietary modeling software, MetrixLT. Both software programs utilize load profiles by rate schedule from class load studies conducted by the Company and the sales forecast 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 peaks. The underlying peak forecast for Lana'i and Moloka'i Divisions were derived by employing a sales load factor method that compares the annual sales in MWh against the peak load in MW multiplied by the number of hours during the year. 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 underlying system peak forecast for customer-sited distributed generation or electric vehicles as forecasted system peaks are expected to occur during the evening. It was assumed most of the distributed generation would be PV systems without batteries and electric vehicle charging was not expected to significantly affect the evening peak.

Customer-Sited Distributed Generation

The projections for impacts associated with customer-sited distributed generation were developed separately for residential and commercial customers and aggregated into an overall forecast for distributed generation, predominantly PV systems. Eligible market size was based on technical penetration limits, absolute sizes of customer classes, and future growth assumptions. In the near term (through 2016) a set rate of interconnections under the existing company tariffs were used based on simplified assumptions about queue release and the pace of new applications. Beyond 2016 the Company assumed that a new distributed generation tariff structure ("DG 2.0") would be implemented across all customer classes. Benchmarked relationships between the payback period of PV systems and customer uptake rates, projected market demand for new PV systems among all residential and commercial customer classes were applied to installed PV capacity as of year-end 2016 as a starting point for the long term. For purposes of modeling, PV energy production levels for hourly or sub-hourly information are derived from actual solar irradiance field data. Consistent with the Distributed Generation Interconnection Plan, beyond 2016, DG PV is assumed to provide active power control and is therefore curtailable during periods when the system cannot accept excess DG energy. The DG curtailment priority is assumed to be senior to transmission-connected utility-scale resources, that is, DG is curtailed after utility-scale resources are curtailed.

Energy Efficiency

The projections for impacts associated with energy efficiency measures are consistent with impacts achieved by the Public Benefits Fund Administrator, Hawai‘i Energy, over the next five to ten years. The Company assumed that it would take several years before changes to building and manufacturing codes and standards are integrated into the marketplace. Following these types of changes, the impacts would grow at a faster pace in order to meet the longer term energy efficiency goals (expressed in GWh) identified in the framework that governs the achievement of Energy Efficiency Portfolio Standard (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.

Electric Vehicles

The development of the electric vehicles forecast was based on estimating the number of electric vehicles purchased per year then multiplying that number by an estimate of "typical" electric consumption using charging requirements for plug-in hybrid electric vehicles. As with any emerging technology, estimating impacts are challenging because the technology is so new and historical adoption and impact data is limited.

Demand and Energy Requirements

The demand served and energy generated by the Company is greater than the demand and energy requirements at the customer's location (net of the amount conserved or self-supplied) due to energy losses that occur in the delivery of power from a generator to a customer. Customer level demand and energy forecasts are increased accordingly to account for these losses.

The net results are the quantities of demand and energy that must be supplied from the Company's generating fleet, including assets owned by the Company and assets owned by third parties who sell to the Company under Power Purchase Agreements (that is, utility-scale independent power producers).

Peak Demand Forecasts

The peak demands of each operating Company forecasted through the study period (expressed at the net generation level) are shown in Figure 4-2 through Figure 4-6.

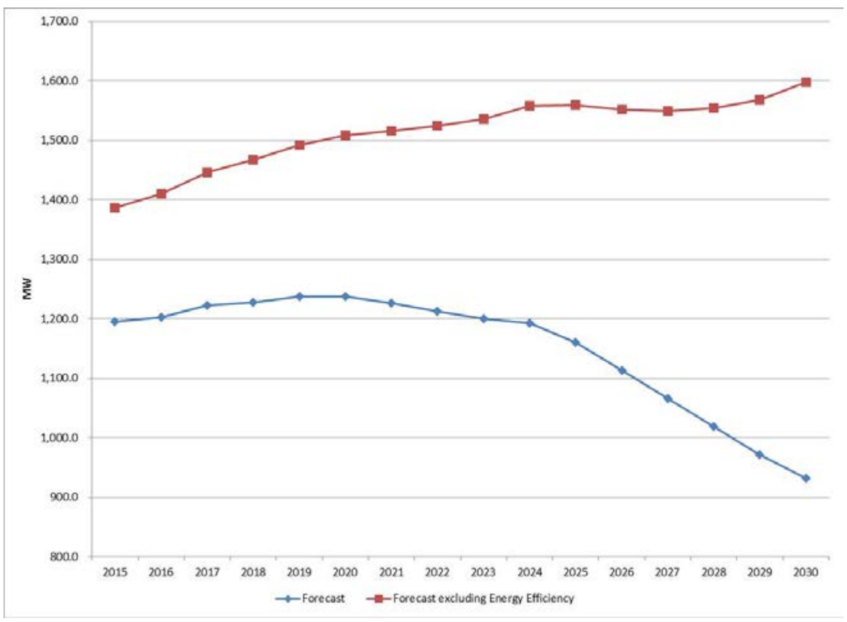

Figure 4-2. Hawaiian Electric Peak Demand Forecast (Generation Level)

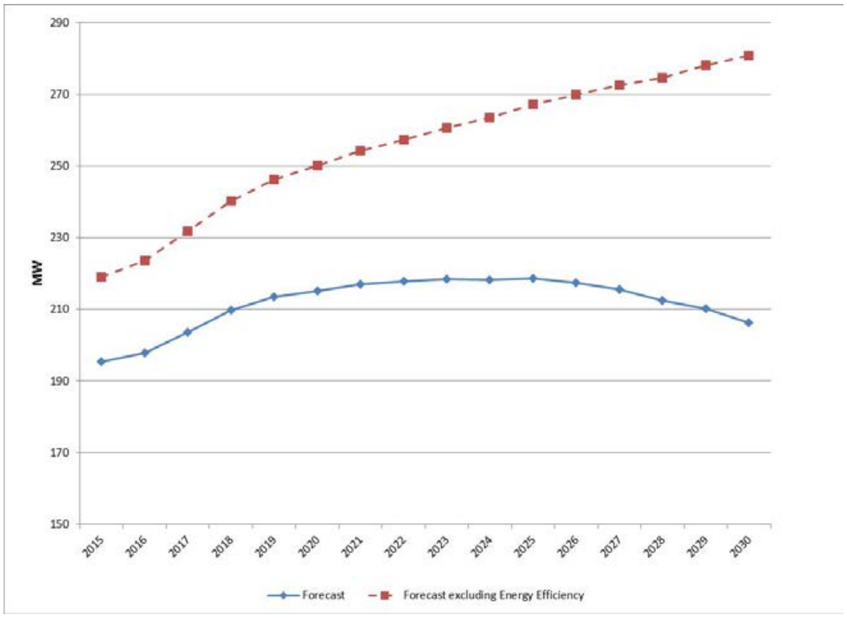

Figure 4-3. Maui Peak Demand Forecast (Generation Level)

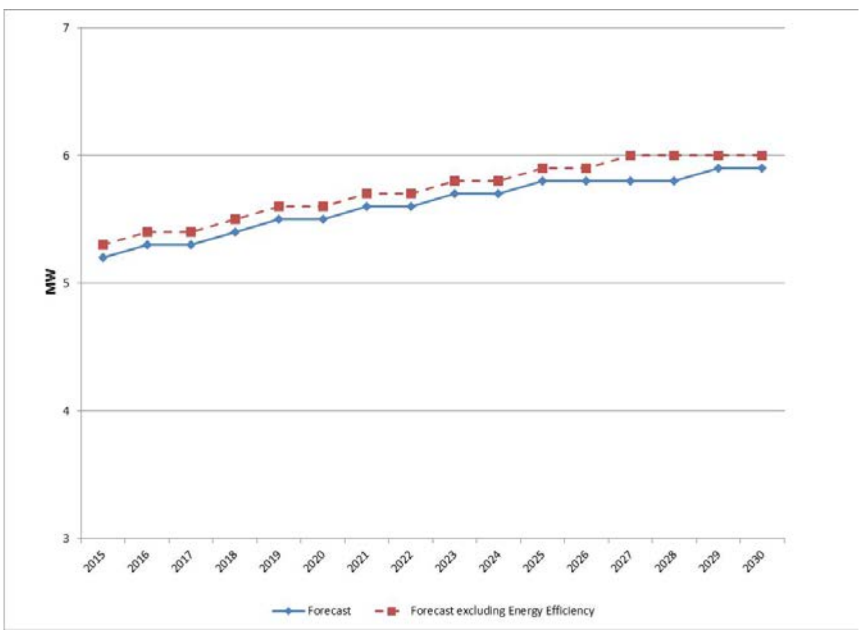

Figure 4-4. Lana'i Peak Demand Forecast (Generation Level)

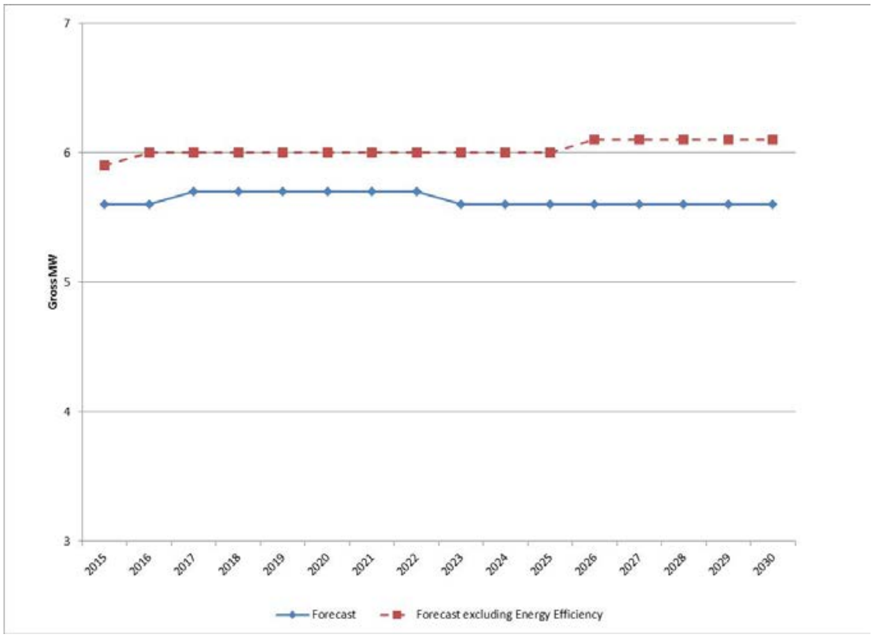

Figure 4-5. Moloka'i Peak Demand Forecast (Generation Level)

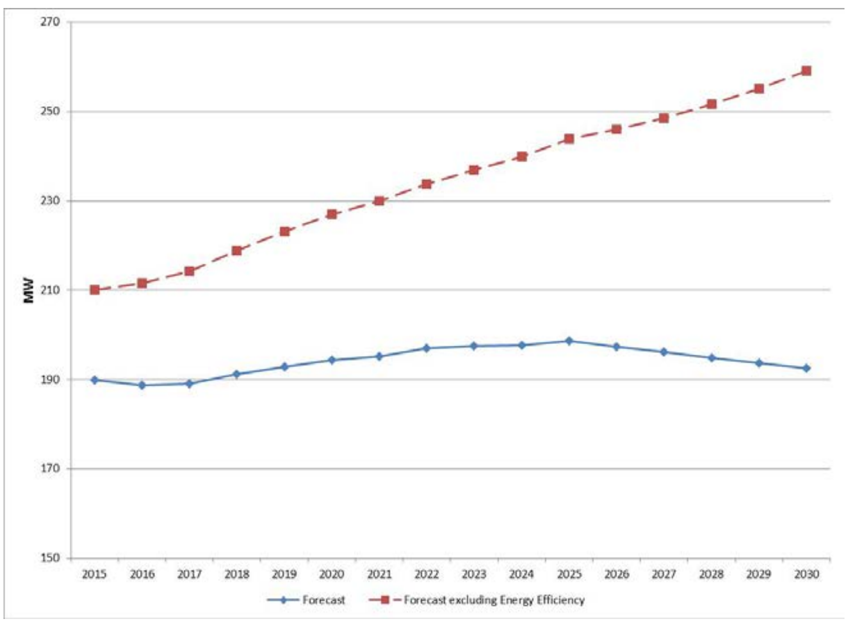

Figure 4-6. Hawai'i Electric Light Peak Demand Forecast (Generation Level)

Energy Sales Forecasts

The forecasts of energy requirements to be served by each operating Company through the study period (expressed at the customer level) are shown in Figures 4-7 through 4-11.

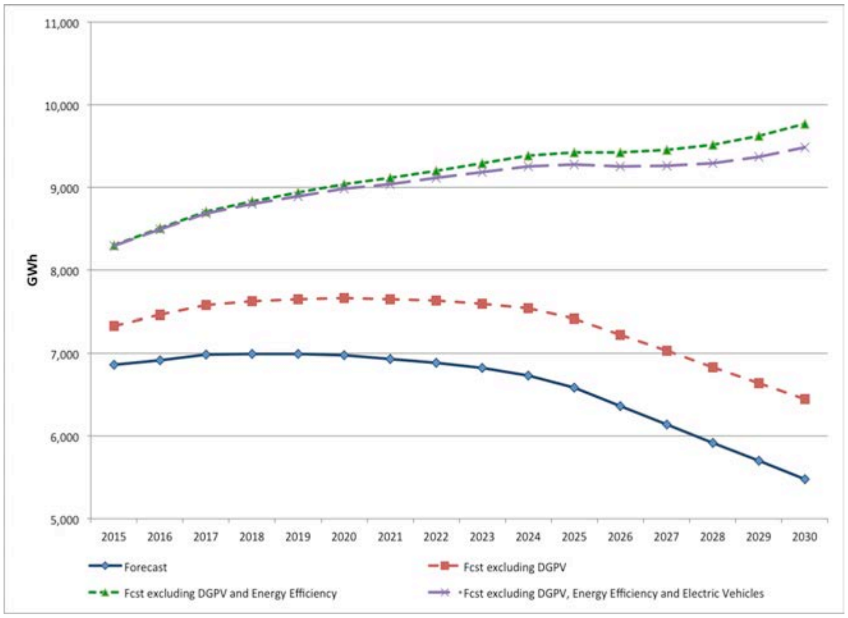

Figure 4-7. Hawaiian Electric Energy Sales Forecast (Customer Level)

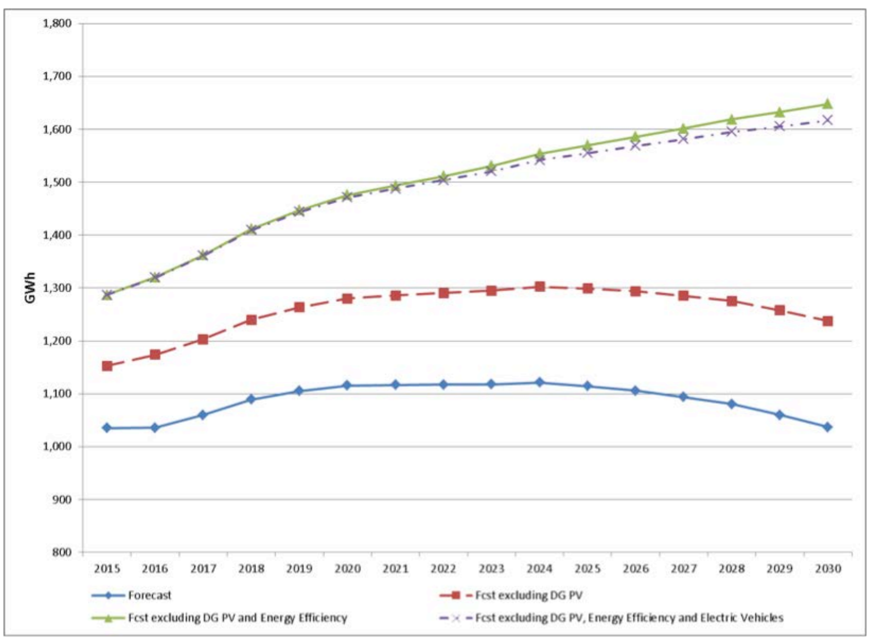

Figure 4-8. Maui Energy Sales Forecast (Customer Level)

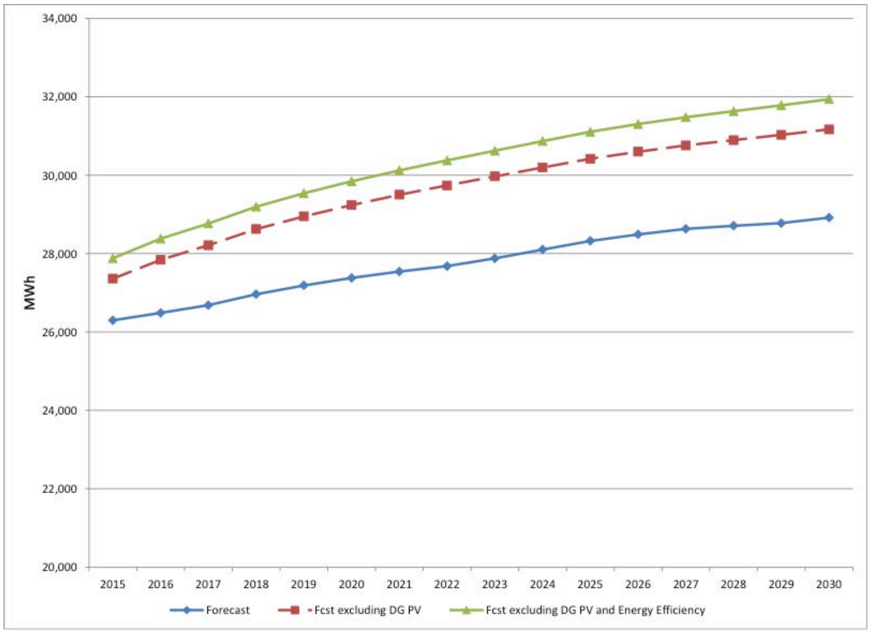

Figure 4-9. Lana'i Energy Sales Forecast (Customer Level)

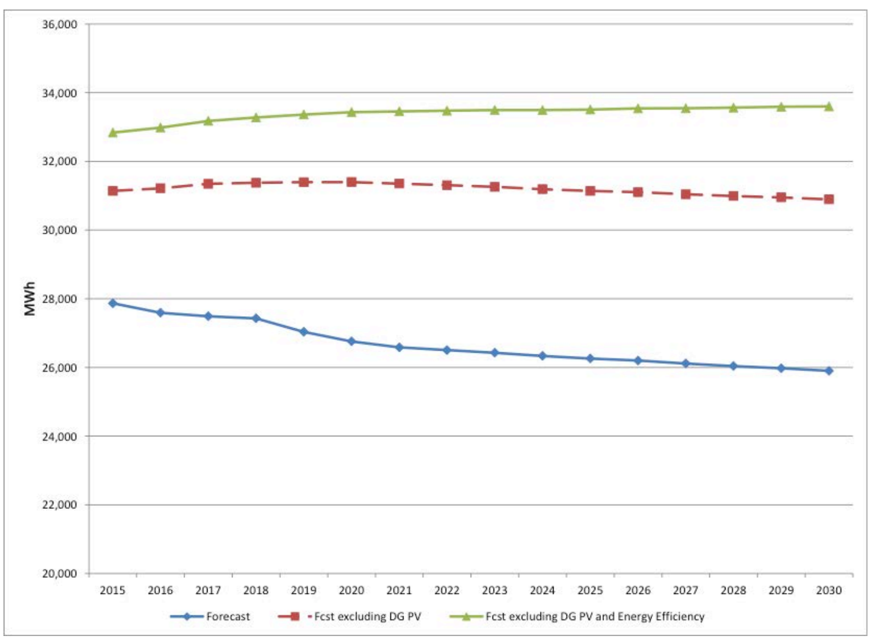

Figure 4-10. Moloka'i Energy Sales Forecast (Customer Level)

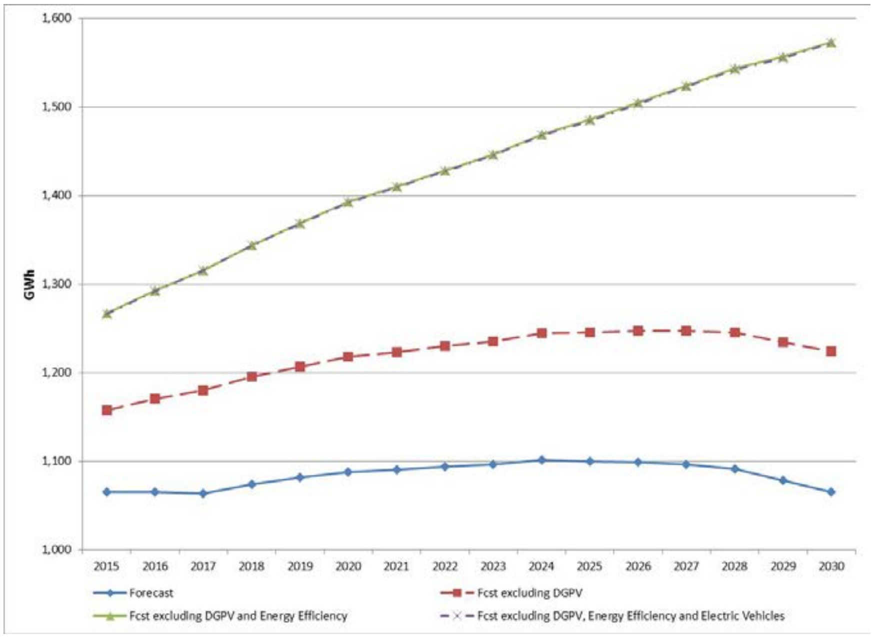

Figure 4-11. Hawai'i Electric Light Energy Sales Forecast (Customer Level)

It is important to note that both the net peak demand and the net energy requirements, which the Company is obligated to serve, are relatively flat and even decline toward the end of the study period. This is the result of energy efficiency and an assumed future level of customer-owned distributed generation (mostly distributed solar PV).

In addition to the forecasts described above, the Company incorporated the effects of implementing dynamic and critical peak pricing programs. Load shifting and energy savings could be realized through the implementation of these programs. Hourly load adjustment factors were based upon the application of demand elasticity adjustments to assumed time of use rate structures. Refer to Chapter 4 of the Integrated Demand Resource Portfolio Plan filed on July 28, 2014 under Docket No. 2007-0341 for additional information on the programs.

Load Profiles

A very important assumption related to the demand and energy forecast is the profile of the demand over a given time period for example, a day, week, month, or year. Of interest to the modeler is the demand profile net of customer-owned generation, since the net profile is what must be met through the dispatch of resources available to the system.

For the PSIP runs, the load profile was modeled two ways: 1) the PSIP analyses were performed using an annual hourly load profile (that is, 8,760 data points for a year) was used to model the system, and 2) the PSIP sub-hourly analyses used 5-minute load profile data (that is, 105,120 data points for a year). The sub-hourly models were used to more accurately model intra-hour issues associated with ramping of generating resources and energy storage in response to variable renewable generation.

The net load profile of the system has changed dramatically over the past few years as a result of the proliferation of customer-sited distributed generation in the system. For the PSIP, a system gross load profile is assumed, and the profile of customer-sited distributed generation is subtracted out, resulting in the net load profile.

FUTURE RESOURCE ALTERNATIVES

Generation Alternatives

The following generating technologies were considered as resource options in the PSIP analyses. More detailed descriptions of each are found in Appendix F.:

- Simple-cycle combustion turbines
- Combined-cycle
- Internal combustion engines
- Geothermal
- On-shore wind
- Utility-scale solar PV
- Waste-to-energy
- Pumped-storage hydroelectric (see Appendix J)
- Biomass

Distributed Solar Generation (DG-PV)

The DG-PV forecast was determined outside of the resource optimization models, and therefore, the DG-PV forecast is a fixed input for purposes of the PSIP optimization models. Therefore, distributed generation was not treated as a resource “option” in the generation optimization models. If DG-PV is added as a resource option in the resource optimization models, DG-PV will never be selected it as an economical choice. In addition, utility-scale fixed-tilt solar will produce more energy per KW of installed solar PV capacity because the panel tilt and orientation of utility-scale solar can be more precise than can be achieved with distributed solar PV. This is reflected in the planning assumptions for solar PV where the utility-scale PV has a higher capacity factor than DG-PV.

During the study period, the amount of total installed DG on the Companies' systems is assumed to increase almost three-fold, from 328 MW (as of 7/15/2014) to just over 900 MW by 2030. The resulting installed DG capacity represents over 65% of the forecasted peak demands of the Companies in 2030, resulting in one of the most aggressive DG-PV programs in the world. Integrating this amount of DG-PV without affecting system reliability is a sizeable challenge that is addressed in Chapter 5. Figure 4-12 shows the forecast assumptions for DG-PV.

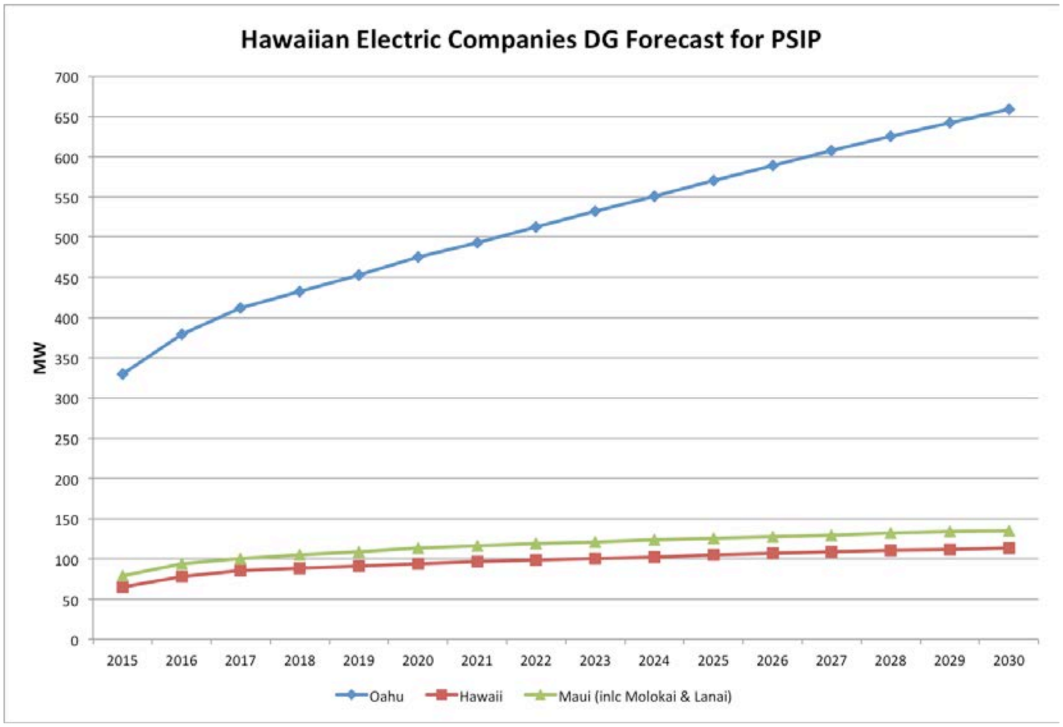

Figure 4-12. Installed DG Forecasts

Constraints on Generation Alternatives

The Companies made certain assumptions regarding the aggregate amounts of resource-types that can be installed across their service areas ("constraints"). The generation resource constraints were based on land availability, resource (for example, water availability, waste availability, etc.) limitations, available sites, commercial readiness and other factors that constrain the installation of certain resource types on specific islands. Siting constraints were not assumed for thermal generating resources and energy storage; rather it is assumed that those resources can be located on or near existing power plant and substation sites. The generating resource constraints by island are summarized in Table 4-2.

Constrained Resource Type	Resource Constraint by Island (Incremental to Existing and Committed)		
	O'ahu	Maui	Hawai'i
Geothermal	0 MW	25 MW	50 MW
On-Shore Wind	50 MW	> 500 MW	> 500 MW
Solar PV (Utility Scale)	360 MW	> 500 MW	> 500 MW
Waste-to-Energy	0 MW	10 MW	5 MW
Pumped Storage Hydro	50 MW	120 MW	90 MW
OTEC	100 MW	0 MW	0 MW
Biomass	30 MW	0 MW	34 MW
Ocean Wave / Tidal	0 MW	0 MW	0 MW

Table 4-2. PSIP Assumed Incremental New Resource Constraints by Island

New Generation Planning Assumptions vs. Future RFPs

The resource options and constraints discussed above are intended only for use as planning assumptions for the 2014 Power Supply Improvement Plans. The resource options and constraint assumptions set forth herein should not be interpreted as a policy position of the Hawaiian Electric Companies. The resource options and constraint assumptions set forth herein do not modify any of the Companies' policies and / or positions with respect to any ongoing or proposed PPA negotiation, pilot projects, or demonstration projects in which the Companies participate.

Third parties' responses to any future Request for Proposals by the Companies for the procurement of power supply resources and/or energy storage resources may include any resource option on any island, unless specifically excluded by the terms of the RFP, based on specific technical requirements. Any such proposals received by the Companies in response to a power supply and/or energy storage RFP will be evaluated on their merits. Such evaluation will include, at a minimum:

- Site control status.
- The commercial readiness of the technology proposed.
- Community acceptance of the project proposed.
- Confidence level regarding the ability to site, license, permit, and constructability the project proposed.
- Confidence level regarding the site-specific costs of the project proposed.
- Any other evaluation factors deemed relevant in an approved RFP document.

Cost and Operating Characteristics of New Generation Alternatives

The assumptions for capital cost for new generating resource options is based on the *Cost and Performance Data for Power Generation Technologies*, a report prepared for the National Renewable Energy Laboratory, by Black & Veatch, February 2012[14]. The Company intends to seek competitive bids for all new generating resources beyond the present committed additions. If the least cost resource proposals received indicate costs that are higher than what has been assumed in this PSIP, the capital costs associated with resource additions will be higher.

The detailed cost and operating characteristics of generation alternatives are included in Appendix F – Modeling Assumptions Data.

Acquisition Model for New Generating Resources

For purposes of the PSIP analyses, all new generating resources (beyond committed generating resources) are assumed to be owned by third parties. A surrogate for third party pricing was determined in two steps:

- The projected cash flow associated with the new generation resource (excluding fuel and variable O&M costs) were computed based on capital costs, operating costs, and utility revenue requirement profiles as if the utility owned the project.
- This cash flow was then levelized using the utility's cost of capital to obtain a levelized cost of the resource, which was assumed to be the PPA price.

Fuel costs and variable O&M were treated as pass-through costs for modeling purposes and will be included in bill impact calculations in the financial model.

This is a simplifying assumption for purposes of the PSIPs and is not intended to convey any preference or lack thereof for an acquisition model for future generating resources. At the time a resource acquisition is considered, the Companies will evaluate the appropriate business model for each new resource based on what is in the best interest of customers.

Energy Storage Alternatives

Utility-scale energy storage options are made available as a resource option in the PSIP production modeling. Appendix J: Energy Storage Plan contains a complete discussion of energy storage, including pricing and operating assumptions for energy storage. Energy storage is considered for providing ancillary services, to meet security constraints, and for load shifting.

[14] This report is available at http://bv.com/docs/reports-studies/nrel-cost-report.pdf.

The following storage durations were considered for energy storage to serve the indicated purpose:

- Regulating Reserves: 30 min
- Regulating Capacity: 30 min
- Contingency Reserves: 20 min
- Long-term Reserves: 3 hours
- Inertial, Fast Response Reserves: 0.05 min

Demand Response

The following demand response programs were considered in the PSIP analysis:

- Residential Direct Load Control (RDLC)
- Residential Flexible
- Commercial & Industrial Direct Load Control (CIDLC)
- Commercial & Industrial Flexible
- Water Pumping
- Customer Generation
- Time-of-Use (TOU) and Critical Peak Pricing (CPP)

The assumed impacts on capacity needs and energy requirements from these programs are detailed in Appendix F – Modeling Assumptions data.

FUEL PRICE FORECAST

The Companies anticipate continued consumption of liquid and gaseous fuels during the study period. However, the preferred plan incorporates a major shift away from imported liquid fuels (fuel oil, diesel, etc.) to biofuels and natural gas from LNG. In particular, the following fuels are available to the planning models during the planning period:

- Natural gas (from LNG)
- Biodiesel
- Lower sulfur fuel oil (LSFO)
- Black Pellet Biomass

The price forecast (in $/MMBtu) is included in Appendix F. Modeling Assumptions Data.

NON-TRANSMISSION ALTERNATIVES

Non-transmission alternatives (NTAs) were evaluated to determine whether using technologies and programs like distributed generation, energy storage and demand response could avoid transmission capital investments, and potentially reduce the cost of service to customers. An example of an NTA would be new generation located in specific areas to avoid the construction of transmission lines while allowing the Companies to meet adequacy of supply requirements (see Reliability Criteria assumptions discussion below.

Where applicable, NTA assumptions were made regarding their implementation in the Preferred Plan.

Hawaiian Electric

A transmission upgrade is anticipated in the Hawaiian Electric system during the study period. NTAs will be evaluated as part of the application to approve capital for this project

Hawai‘i Electric Light

A single transmission upgrade is anticipated in the Hawaiian Electric system during the study period. NTAs will be evaluated as part of the application to approve capital for this project

Maui Electric

In the Maui Electric system, construction of new transmission lines and substations are being considered to address the following system issues:

- Under voltages, thermal overloads and voltage stability on the Central Maui 23kV system due to the retirement of KPP.
- Under voltages and voltage stability in South Maui.
- Overloading of distribution substations.

These system issues can occur under normal and/or N-1 conditions[15]. Upgrades to the transmission system were purposed as solutions to help address the issues. Table 4-3 lists the issues, affected areas, and system upgrades that were proposed. Figure 4-13 provides a map of Maui identifying related substations and system network.

[15] A condition that happens when a planned or unplanned outage of a transmission facility occurs while all other transmission facilities are in service. Also known as an N–1 condition.

Issue	Area	System Upgrades
Under voltage, thermal overloads, and voltage stability	Central Maui	
23kV System	23 kV Waiinu-Kanaha upgrade to 69 kV and re-conductoring of MPP-Waiinu and MPP-Puʻunene from 336AAC to 556AAC	
Under voltage and voltage stability	South Maui	Kamalii Substation and MPP-Kamalii 69 kV transmission line
Overloading of distribution substations	Central and South Maui	Construction of Kuihelani (Central Maui) and Kaonoulu (South Maui) Substations

Table 4-3. Maui Electric System Issues and Transmission Solutions

The possibility of using the NTAs to fulfill the shortfall of capacity of 40 MW resulting from the Kahului Power Plant (KPP) decommissioning scheduled to begin in 2019 was also considered.

Definition of terms used in this report:

- "23 kV system"— 23 kV substations and feeders except Kula or Haleakala Substations and feeder to Hana Substations.
- "Central Maui"— Key substations include Kahului, Wailuku, and Kanaha.
- "South Maui"— Key substations include Kihei, Wailea, and Auwahi.

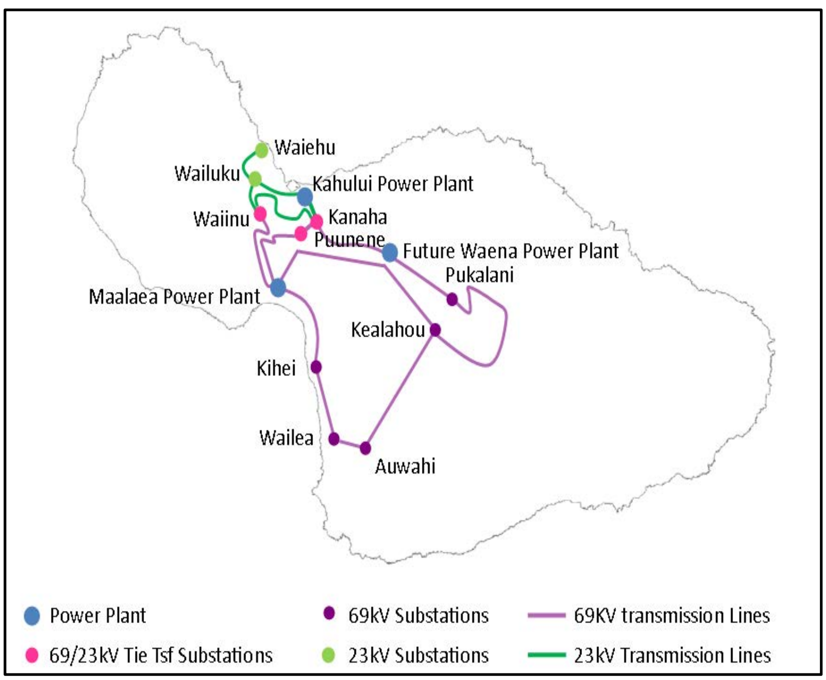

Figure 4-13. Transmission Overview for Key Maui Electric Substations Related to NTAs

NTA assumptions are listed below:

- NTAs are considered as possible alternatives to transmission system upgrades
- Combinations of NTAs are possible (requires more detailed studies)
- Transmission overload criteria
  - Normal conditions = normal ratings
  - N-1 contingency conditions = emergency ratings
- Voltage criteria
  - Over voltage violation: bus voltage greater than 1.05 per unit
  - Under voltage violation: bus voltage less than 0.9 per unit
- Kahului Power Plant units K1, K2, K3, and K4 will be decommissioned in 2019, resulting in a capacity shortfall of approximately 40 MW
- Pursuant to the Preferred Plan, Waena Power Plant will be online in 2019
- Ma'alaea Power Plant units M4, M5, M6, M7, M8, and M9 will be decommissioned in 2022 resulting in a capacity shortfall of approximately 35 MW.

With the transfer capability limitations in Central and South Maui, the best solution should extend the transfer limits to allow the system to operate within a reasonable margin away from the limits. The bus voltages in the area will be used as a guideline to determine how much the load would need to be reduced for the buses to have a voltage around 0.95 per unit, which provides a reasonable margin above the planning criteria minimum of 0.90 per unit.

DR and DG-PV were among alternatives examined to potentially eliminate the need for these transmission upgrades, however, they cannot be considered reliable solutions. During an N-1 contingency, DR does not have the ability to respond quickly enough to prevent severe disturbances[16]. Additionally, DG-PV provides little to no generation during system peak periods[17], and therefore cannot help reduce the loads to avoid under voltage and thermal overload violations during normal or N-1 contingency conditions.

Central Maui

With the retirement of KPP, the Central Maui load on the 23 kV system will need to solely rely on the generation from MPP. The system has three 69/23 kV transformers that interconnect the 23 kV system and the 69 kV system. These transformers are located at Waiinu, Kanaha, and Pu'unene substations. During an N-1 contingency where one of

[16] With a large discrepancy between generation and load the frequency can decline immediately (0–3 seconds), where controls for DR have a response time of over 5 seconds.

[17] System peak occurs during the evening around 7:00 PM, when PV has minimal impact to the system.

these feeders[18] becomes unavailable, under voltages and thermal overloads occur on the remaining transformers. If there is too much power being transferred to the 23 kV system from the 69kV system, the system may not be able to manage the transfer and can experience a voltage collapse or island wide blackout. Therefore, the upgrade of the 23 kV Waiinu-Kanaha line to 69 kV and the reconductoring of MPP-Waiinu and MPP-Pu‘unene are proposed to shift some of the loads from the 23 kV system onto the 69 kV system.

The *Kahului Power Plant Retirement-Comprehensive Assessment* (included in the Maui Electric PSIP) provides analysis to locally reduce the amount of load and help with the voltage issues on the 23 kV system. The following NTAs were considered: distributed generation (DG), battery energy storage system (BESS), and synchronous condensers from decommissioned KPP units. The DG and BESS NTAs could provide the system with generation to meet the adequacy of supply, however, acres of property would be required to accommodate the large amount of DG or BESS. Installing these NTAs would be difficult due to the size of available property and need for zoning and air quality permits in Central Maui. Converting the KPP units to synchronous condensers or installing DG or BESS at the KPP location were determined to be unfeasible because, KPP is located in a tsunami inundation zone[19]. Upgrading the transmission system in Central Maui is the most feasible option given in Central Maui the lack of available real-estate, existing residential communities, and the tsunami inundation zones.

South Maui

In South Maui, the loads from Kihei and Wailea are mainly served through the MPP-Kihei 69 kV transmission line. If there is an outage of the MPP-Kihei line, the South Maui load will need to be served from the MPP-Kealahou 69 kV line, which increases the electrical distance serving loads. The longer distance would result in major losses[20] and possibility of a voltage collapse. The distance would increase to approximately 23 miles, as shown in Figure 4-14.

[18] MPP-Waiinu or MPP-Pu‘unene.

[19] Maui Electric’s preference is to avoid Tsunami inundation zones as locations for new generation, where feasible.

[20] Due to higher impedance and an increased voltage drop from the source to the load.

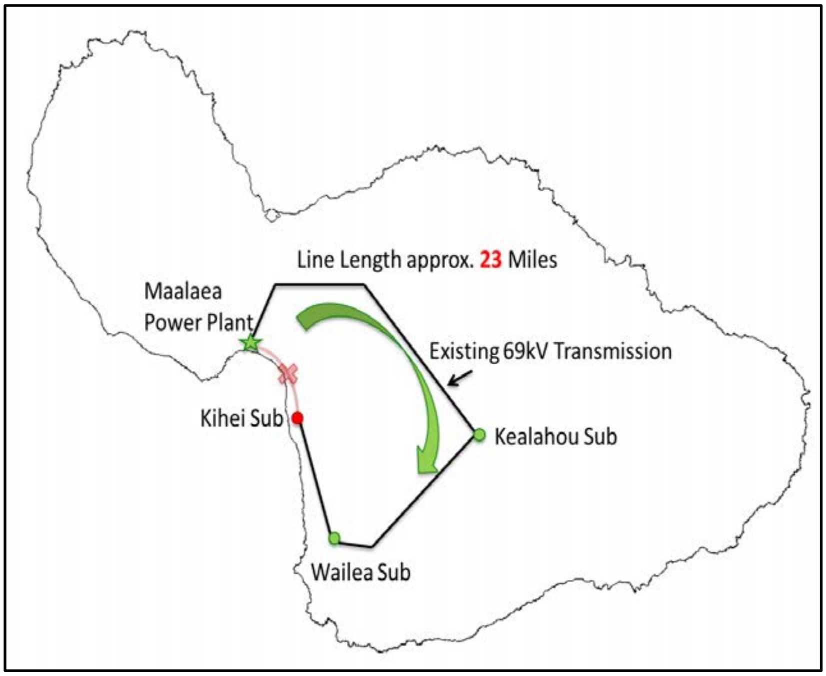

Figure 4-14. Longer Distance Required to Serve Loads in Kihei Under an N-1 Contingency

The *Ma'alaea-Kamalii Transmission Line Alternatives* report (included in the Maui Electric PSIP) analyzed various NTAs to defer the construction of new transmission infrastructure. For voltages to remain within a reasonable margin above 0.90 per unit, the total load in South Maui would need to be reduced by at least 20 MW. Several of the NTAs considered increased the voltages in South Maui, but did not effectively reduce both the load issue and possibility of a voltage collapse.[21] For example, the synchronous condensers and static capacitors can increase the voltages but these transmission system facilities do not generate MW to serve the load.

The hybrid of a BESS and DG is considered to be the optimal plan. A hybrid combination of a BESS and DG would shorten the duration of the BESS needed (reducing costs) and allow the DG to only be started in the case of a contingency, as opposed to being run whenever the system load is above 150 MW (lowering fuel consumption). Maui Electric plans to pursue this option based on the following:

All plans in the Maui Electric PSIP include a BESS for Contingency Reserve in compliance with EPS System Security Study.

The Contingency Reserve BESS (20MW: 30 Min) is assumed to be located in South Maui so that when a transmission event occurs in South Maui, the BESS will be able to operate

[21] An under-voltage load shed (UVLS) scheme is currently imposed at Kihei and Wailea substations during system loads greater than 150 MW, in order to avoid a voltage collapse. With load curtailment, customers remain offline until the system returns to normal conditions, or the system load decreases below 150 MW. The UVLS scheme is not a viable long-term solution.

for 30minutes. Within that time, the 24MW of Internal Combustion Engine (ICE) generation, located in South Maui, will be able to start in order to support South Maui transmission system.

If the Contingency Reserve BESS is not located in South Maui, then the 24MW of ICE generation in South Maui will have to operate daily when the system load is 150MW or greater to support the South Maui system in case a transmission event occurs.

Maui Electric Distribution Transformer Overloads

Our forecasts indicate that several distribution transformers will be overloaded in Central and South Maui in the near future. This prompted the need for a new distribution substations[22] to be built to help alleviate the loads on the existing distribution transformers. DG and BESS were considered as alternatives to building a new distribution substation that could potentially lessen the load on existing substations where the overloading occurs, contribute toward firm capacity, and help alleviate the need for additional transmission lines in the area. Preliminary assessments found these options to be unfavorable due to permitting, physical, and/or financial constraints.

RELIABILITY CRITERIA

The Hawai‘i Reliability Standards Working Group (RSWG) Glossary of Terms[23] defines “Reliability” as follows:

> ***Reliability.*** An electricity service level or the degree of performance of the bulk power (“utility” in Hawai‘i) system defined by accepted standards and other public criteria. There are two basic, functional components of reliability: operating reliability and adequacy.

The RSWG Glossary of Terms goes on to define “adequacy” and “operating reliability” and as follows:

> ***Adequacy.*** The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

> ***Operating reliability.*** The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

The North American Electric Reliability Corporation (NERC) formally replaced the term “security” with the term “operating reliability” after September 2011, when the term

[22] Kuihelani in central and Kaonoulu and Kamali’i in South Maui.

[23] RSWG Glossary of Terms. Docket No. 2011-0206.

"security" became synonymous with homeland protection in general, and critical infrastructure protection in particular[24].

The Hawaiian Electric Companies have continued to use the term "system security" with the exact same meaning as "operating reliability." "System security" is therefore the term used herein.

Adequacy of Supply

One of the most commonly used planning metrics for designing a system to meet the adequacy of supply requirements is "reserve margin." For purposes of the PSIPs the production modeling teams assumed a minimum 30% planning reserve margin for generation. As the systems evolve, the target reserve margin will be periodically evaluated to ensure resource adequacy and supply, with consideration of the resource risk based historical performance of the types of resources providing the capacity.

System Security

The derivation of system security requirements for the PSIP analyses is explained in detail in the following section.

SYSTEM SECURITY REQUIREMENTS

Electric power grids operate in a manner that provides reliable and secure power during both normal conditions and through reasonably anticipated events. To achieve this reliable and secure operation, the grids operate under system security constraints. These constraints include requiring certain resources to be utilized and require the power system to be operated in certain ways.

In traditional power systems[25], conventional thermal generating units provide most of the electric energy and meet most of the security constraints by supplying system inertia, frequency response, and other ancillary services as part of their inherent operating characteristics and governor controls. As new types of generation, such as wind and solar PV, became significant providers of energy and displaced conventional thermal generation, the requirements to ensure there is a sufficient supply of grid services for

[24] Source: http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

[25] In this context, a "traditional power system" or a bulk power system (BPS) is a large interconnected electrical system made up of generation and transmission facilities and their control systems. A BPS does not include facilities used in the local distribution of electric energy. If a bulk power system is disrupted, the effects are felt in more than one location. In the United States, the North American Electric Reliability Corporation (NERC) oversees bulk power systems.

security and reliability becomes more important. Due to their inherent characteristics, variable generation resources often cannot supply these services, requiring other standalone services to be provided to the grid or special design modifications be made to the variable generators. Further, the variable output from these resources can increase the need for grid services.

The majority of variable energy resources are connected to the power system through an inverter. The inverter isolates a variable energy resource from the grid and converts the energy produced into alternating current (AC) power that is then supplied to the electric grid. The inverter allows the power system and the variable energy resources to operate at different voltages and frequencies, optimizing the performance of the variable energy resource in its conversion of source energy (wind and sun for example) to electric energy. Variable energy resources typically do not have the capability to store their energy and do not typically utilize a governor type control, which would automatically adjust energy in response to system balance (frequency). Instead, unless incorporating advanced control systems, they produce the energy that is available from their resource (for example, solar or wind) regardless of system conditions. If the power system suddenly requires more energy, variable energy resources cannot increase their output beyond the available resource energy (unless it was previously curtailed to less than the available resource energy). Because of this reliance on available energy, variable energy resources can typically supply downward regulation—decreasing their power output—but have limited ability to supply upward regulation—increasing their output.

Some variable energy resources (such as wind turbines) may be able supply inertia or fast frequency response through advanced inverter controls. Like conventional generators, this inertia does act to help slow the rate of frequency decline, and can be a faster response—but unlike conventional plants, this response is not sustained and is eventually withdrawn. Variable energy generation does not have the ability to replace the short-duration inertia energy with energy through governor response.

For the Companies' island grids, several ancillary services are required to reliably operate the power system: regulating reserve, contingency reserve, 10-minute reserve, 30-minute reserve, long lead-time reserve, black start resource, primary frequency response, fast frequency response[26], and secondary frequency control. (These services are more fully explained in Appendix E: Essential Grid Services.)

Establishing regulating reserve, contingency reserve, primary frequency response, and fast frequency response are defined by characteristics of the system requirements to maintain target reliability and planning standards. Technical studies have defined these

[26] Fast frequency response is a subcategory of the 10-minute reserve ancillary service.

security requirements; the choice as to how to meet the requirements is often an economic decision based on generation and resource planning studies.

Although the size and resource mix of the Companies' electrical systems have a large degree of variation, the proliferation of variable generation on each of the islands results in similar constraints and challenges among them.

The security requirements for each island can be defined by the requirements for regulating reserve, contingency reserve, voltage support, and fast frequency response. Other constraints (such as ramp rates, 10-minute reserve, and 30-minute reserve) are required but are not the limiting conditions for the power system security.

Regulating Reserve

Regulating reserve is the amount of capacity that is available to respond to changes in variable generation or system load demand to maintain system operation at a target frequency (maintaining close to 60 Hz). Regulating reserve is required for both upward regulation (additional generation or decreased load through demand response) and downward regulation (less generation or increased load through demand response). These responses are required to maintain the balance between total system load demand and supply.

Regulating reserve provides for the normal fluctuation of system load plus the changes in variable generation. Normal fluctuations of system load demand in the Companies' systems are relatively slow and very predictable from day to day. Variable generation—wind generation, distributed solar generation, and utility-scale solar generation—can have extreme variations and dwarf the regulation requirements of normal load demand changes.

Wind Generation

The regulation requirements for wind generation were determined by plotting a years' worth of 2-second data from the SCADA systems for the wind generation facilities on each of the islands. By using 2-second SCADA data from all wind resources, time skew error between the sites is minimized and the actual frequency impact from the changes in total amount of wind is identified.

The amount of regulation capacity that is required is determined by the magnitude of change in wind generation over a given period of time. In wind systems, regulation requirements increase with increasing time intervals. The time interval is largely dictated by the amount of 10-minute reserve available. The 10-minute reserve is critical to the system operator to replace regulating or contingency reserve as they are used by the system. When a wind ramp begins to occur, the system operator cannot predict in real time the duration or magnitude of the ramp event, consequently there is some time in each ramp event where the operator is evaluating the ramp and estimating the severity of the ramp. That time period is assumed to be within the first 10 minutes (or less) of the ramp event. After assessing the ramp event will require mitigation, the operator would typically call upon a reserve resource that will be online within 10 minutes or less (a 10 minute reserve resource). Considering the time for evaluating the event and bringing reserves online, the mitigating resources could be online 20 minutes after the ramp condition started. Therefore, a 20-minute ramp condition is used as the basis to determine the regulation capacity.

The plots in Figure 4-15 through Figure 4-17 depict the variability of wind resources in a typical month on each of the islands.

Hawaiian Electric Wind Generation: The regulating reserve is carried on a 1:1 basis until the actual wind generation exceeds 50% of the nameplate capacity. No additional regulating reserve is necessary for generation levels in excess of 50% of nameplate capacity. The regulation criterion was based on the 20-minute wind ramp events between July 1, 2013 and June 30, 2014 of the Kawailoa Makai, Kawailoa Mauka, and Kuhuku wind generation facilities.

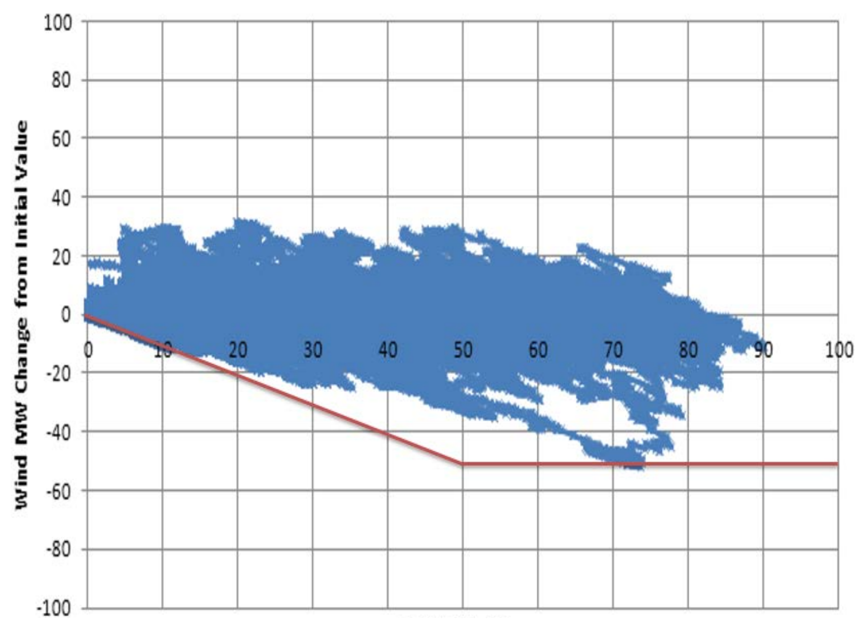

Figure 4-15. 20-Minute Scatter Plot for Hawaiian Electric Wind Generation

Each point in the scatter-plot shown in Figure 4-15 represents one two-second scan from the wind power data. The y-axis shows the total change in wind power between the initial power and 20 minutes after the initial power point. The x-axis shows the initial power output of the wind generation facilities. Interpreting the data for a point (20,–10), the initial total wind power output was 20 MW; twenty minutes later, the wind power output was 10 MW. Therefore, there was a net loss of 10 MW of wind power over those 20 minutes.

The red line represents the recommended regulation capacity. The regulation capacity will not be sufficient for all possible wind ramps, but will be sufficient for the vast majority of wind ramp events.

Hawai'i Electric Light Wind Generation: The wind ramps on the Hawai'i Electric Light system require a similar level of regulating reserve as the Hawaiian Electric system, despite the wind generation facilities having a higher capacity factor. Figure 4-16 shows the wind variability on the Hawai'i Electric Light system for the first half of May 2014 for the Hawai'i Renewable Development (HRD) and Tawhiri wind generation facilities.

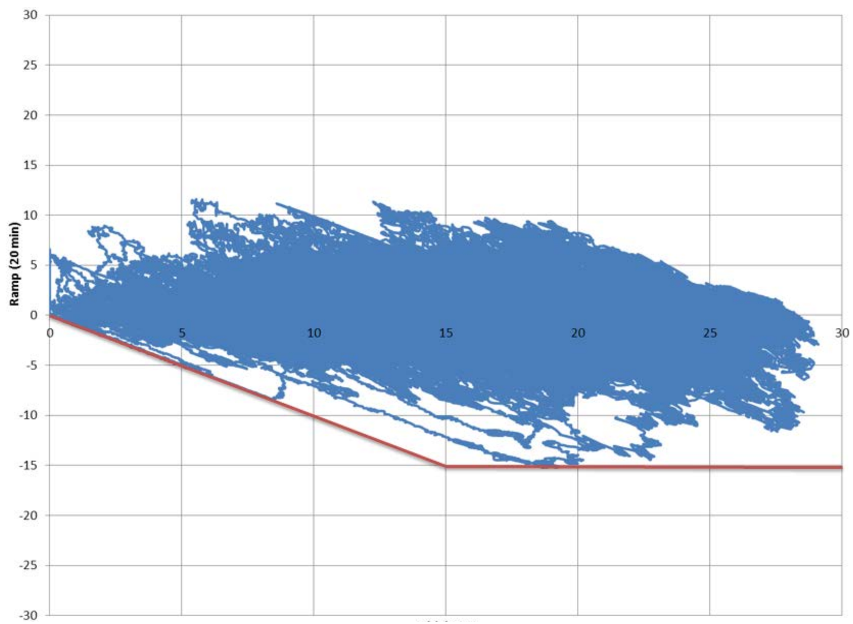

Figure 4-16. 20-Minute Scatter Plot for Hawai'i Electric Light Wind Generation

Maui Electric Wind Generation: The wind ramps on the Maui Electric system require less regulating reserve compared to those for the Hawai'i Electric Light and Hawaiian Electric power systems. The battery energy storage systems (BESS) associated with the wind generation facilities mask some of the more severe ramp rates. Figure 4-17 shows the wind variability on the Maui Electric system for the first half of December 2013 for the Kaheawa One, Kaheawa Two, and Auwahi wind generation facilities.

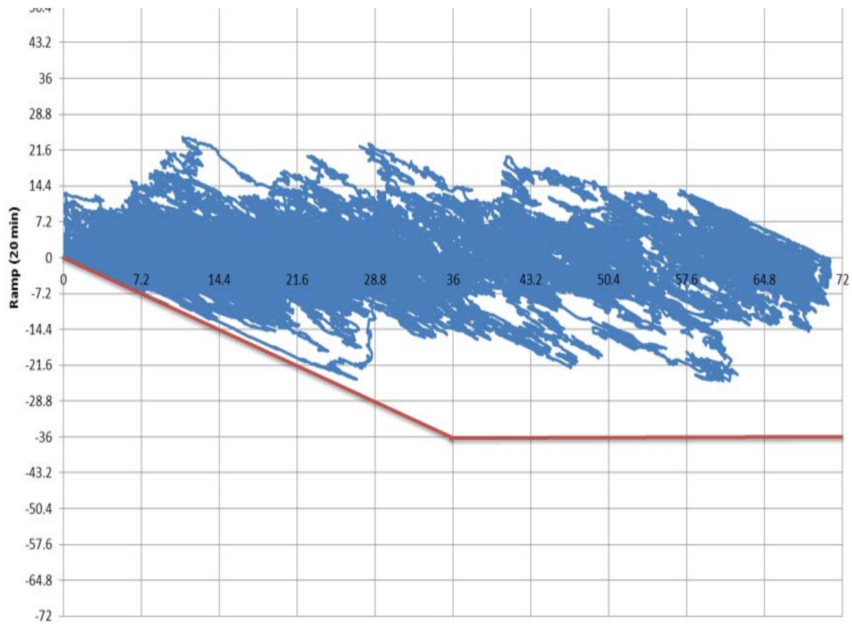

Figure 4-17. 20-Minute Scatter Plot for Maui Electric Wind Generation

Maui Electric is assumed to have a similar requirement to Hawai'i Electric Light if the BESS were used for optimized system requirements as opposed to simply providing ramp rate control of an individual wind generation facility.

Distributed Solar

Distributed solar (referred to as DG-PV in this report) for the power system on Maui Island for 2007 and 2008 estimated island-wide distributed solar generation with a 2-second sample rate. The data assumed an installed DG-PV capacity of 15 MW. The raw data was scaled to estimate the DG-PV generation with 30 MW installed DG-PV capacity. The PV data was analyzed to determine the change in DG-PV generation over a 20-minute time frame for the months from January to July. The results are shown in Figure 4-18, which shows the 20-minute distributed solar generation ramp rate data for the Maui island electric system with 30 MW capacity

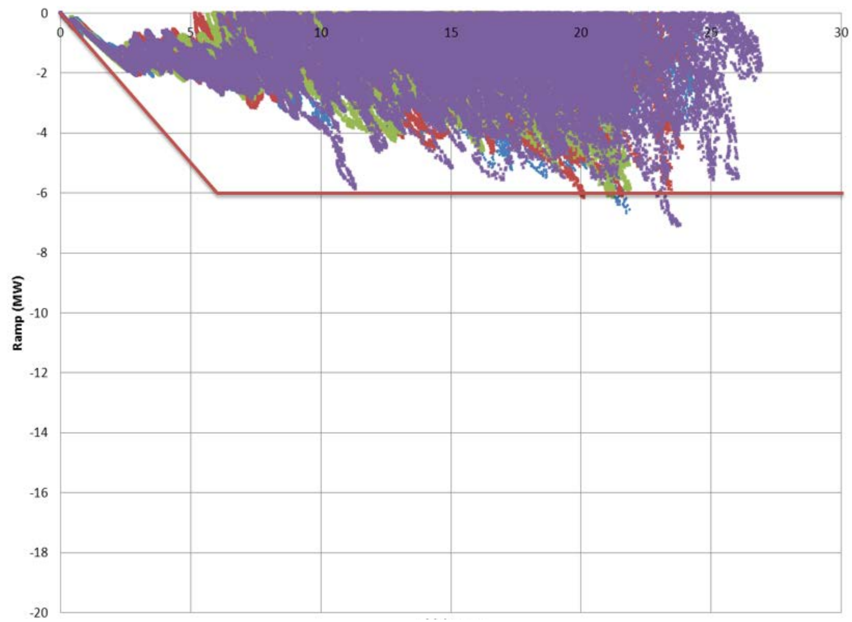

Figure 4-18. Maui Electric 20-Minute Solar Ramps

The x-axis represents the initial solar generation level of 20 MW. The y-axis shows the solar generation change 20 minutes later. Interpreting the data for a point (20,–10), the initial solar generation level was 25 MW; 20 minutes later, the total solar generation level was 15 MW. So the change in solar generation was –10 MW.

The two piece red line shows the recommended solar regulation capacity characteristic: that is, the system operator maintains a regulating reserve with a 1:1 ratio for solar generation levels up to 20% of the solar nameplate capacity and no additional reserve for solar generation levels between 20% to 100%.

Figure 4-19 shows the same regulating reserve criterion applied to the Hawai‘i Electric Light DG-PV. The Hawai‘i Electric Light data was derived from actual solar recordings at approximately 45 locations on the Hawai‘i Electric Light power system. These recordings were scaled based on the distributed solar generation installed near the recording location. The total generation was scaled to represent a system having 100 MW of DG-PV (nameplate capacity).

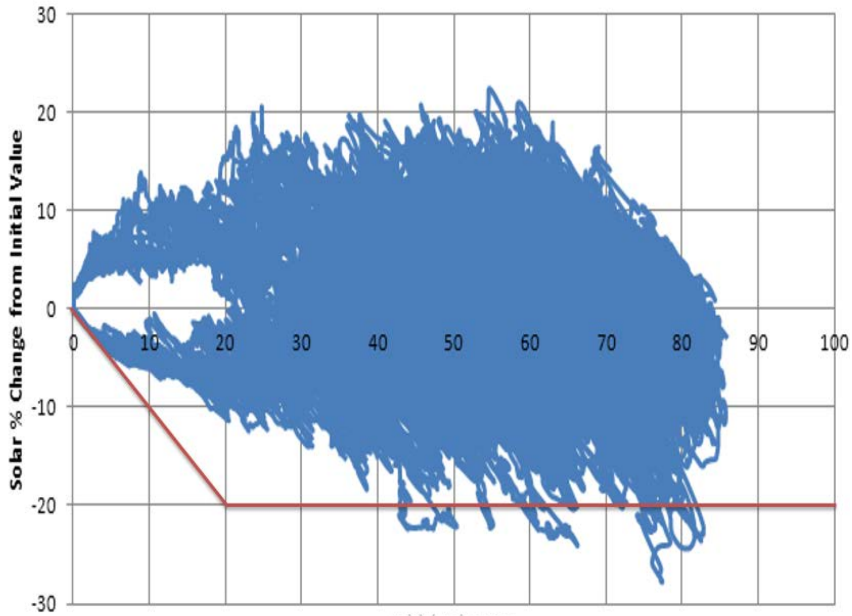

Figure 4-19. Hawai'i Electric Light 20-Minute Solar Ramps for Half of February

Using a 1:1 generation level to regulating reserve capacity ratio, both the Maui Electric and Hawai'i Electric Light data sets produce similar results.

Hawaiian Electric Utility-Scale Solar

There are currently only two utility-scale solar facilities (referred to as PV in this report) on the Hawaiian Electric power system on O‘ahu. Results indicate that over both 30-second and 20-minute time periods, the output of each individual PV facility can vary from 100% to 0%. The estimated, combined effect of the two plants together results in considerable improvement as shown in the 20-minute scatter plots totaling 100 MW of PV capacity in Figure 4-20.

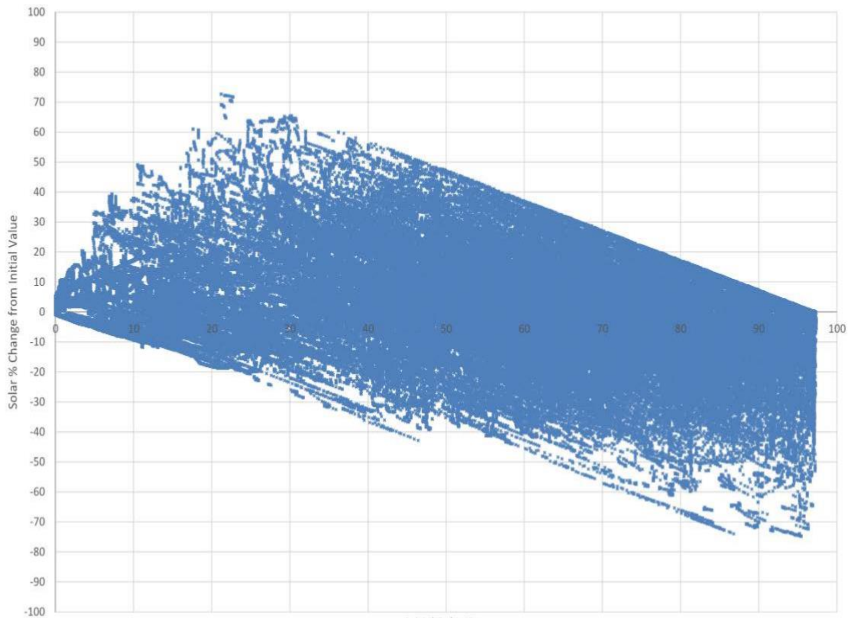

Figure 4-20. Hawaiian Electric Combined Station Class PV

Based on these plots, the required regulation of the two combined wind generation facilities drops from a ratio of 1 MW regulation:1 MW of PV to a ratio of 0.5–0.6:1. The installation of additional PV facilities over a wider area may allow this number to decrease further. Accordingly, the ratio is estimated to decrease to 0.3:1 by 2017 with the addition of more utility-scale solar facilities.

Two-second SCADA data shows that the ramps between wind, DG-PV, and PV do not have 100% correlation. Although there are periods where the ramps cancel each other out, these appear to be random events and not systematic occurrences. Many events are observed when the ramps overlap each other for a portion of the event. Consequently, all regulation requirements are assumed to be additive.

Regulating reserve is a security constraint, however the choice of resource used for the reserve is often determined by economics. Regulation can be supplied by resources immediately responsive to Automatic Generation Control (AGC) and meeting the time frames and accuracy of the response. This can include firm dispatchable generation which may be conventional or renewable, variable generation (which requires partial curtailment for upward reserves), energy storage, and/or demand response.

Some of the resources that can provide regulating reserve can also contribute to contingency reserve. These are the resources that respond to system events without requiring a control signal from AGC, through inertial and governor response (such as thermal generating units). Since allocation of regulating reserves considers economics and therefore may not result in use of resources that can contribute to contingency reserves, additional regulating reserve is not assumed to contribute to contingency reserve. The use of additional thermal generating units to provide regulating reserve would satisfy the contingency reserves requirement, however, the regulating reserve may be supplied by resources with different characteristics than thermal generation, therefore increasing the amount of required contingency reserve.

Contingency Reserve

In planning and operating the power system, care must be taken to ensure that under any circumstances, the system remains operable following the largest single potential loss of energy. This largest possible loss might be due to a trip of a particular generating plant or the loss of critical interconnection equipment. This requirement is known as the single largest contingency criteria and is included as a requirement within TPL-001.[27] The system is able to withstand the loss of the largest single contingency through the implementation of contingency reserve.

Contingency reserve can be provided through resources that respond immediately and automatically to system imbalances. This can include resources such as conventional generation with governor's response, energy storage, or through "fast-acting" demand response. In isolated power systems (such as those on islands), the response requirement of contingency reserve is extremely fast. As the power system evolves and displaces thermal generation with increasing amounts of variable generation, the required response time of the contingency reserve becomes even faster due to the reduced available inertia and frequency response. This very fast response time precludes many types of energy systems from providing effective contingency reserve. Even traditional contingency reserve carried on conventional generation will not be fast enough to provide acceptable contingency response with the reduction in inertia and frequency response resulting from the change in resource mix.

TPL-001 establishes the allowable system performance criteria for the loss of the largest single contingency. The criteria allow a certain amount of the contingency reserve to be

[27] See Appendix M: Planning Standards for the details of TPL-001 as well as details on BAL-052: Planning Resource Adequacy Analysis, Assessment and Documentation Standard. Together, these two standards form the basis for performing system studies.

provided by automatic under frequency load shedding (UFLS) for each system. These amounts currently vary from 12% of the system's customers for Hawaiian Electric to 15% for Hawai'i Electric Light and Maui Electric.

As system inertia continues to decline (for example as the thermal generation is displaced by increasing amounts of variable generation), providing contingency reserve capable of responding fast enough to meet the criteria in TPL-001 becomes more difficult. For instance, the contingency reserve implemented as part of the UFLS system must be fully deployed within 7 cycles (0.12 seconds) of reaching the target frequency. Deployment of effective contingency reserve through governor action of thermal generation also becomes more difficult as the rate of change of frequency decline increases. Many of the contingency reserves that have historically been utilized on the power systems in the Hawaiian Islands are now simply too slow to respond to the new system characteristics.

For instance, the April 2, 2013 loss of the sudden trip of the AES Hawai'i facility totaling 200 MW (that is, 180 MW of net generation to the grid plus 20 MW of ancillary load) occurred at a time when the system had over 400 MW of contingency reserve available as unloaded generation. However, the system frequency declined so fast, that few of the reserves were able to be deployed by the thermal unit governors before experiencing three stages of load shedding (Figure 4-21).

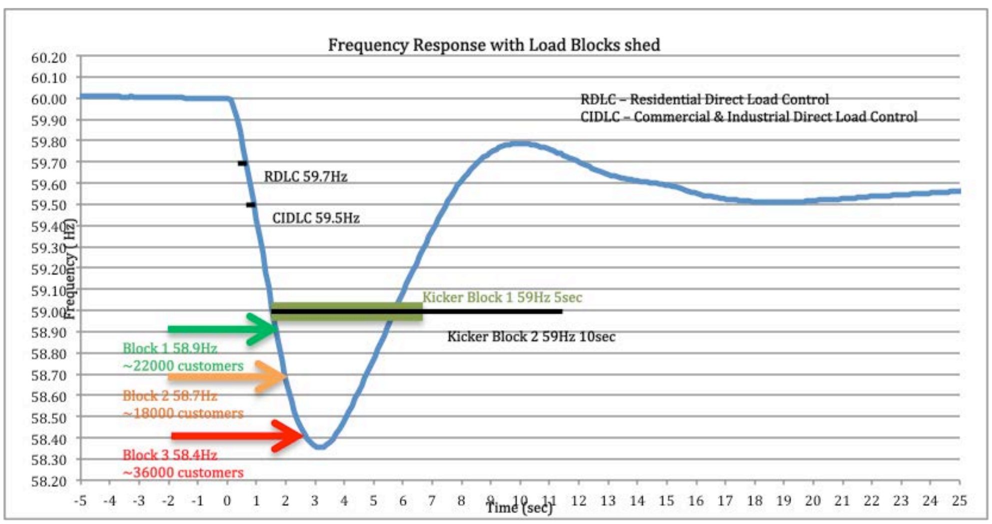

Figure 4-21. Frequency Response with Load Blocks Shed

As the system continues to displace conventional generation from online operation, reliability decreases and security risks increase for contingencies unless mitigated by fast acting contingency reserve. The amount of fast acting contingency reserve required for each system in order to meet the criteria defined by TPL-001 has been studied as part of the PSIP analytics.

For each of the systems, transient stability simulations were used to evaluate the response of the system to the loss of the largest contingency for various operating conditions for the planning years 2015–2030. The simulations were developed to model the boundary conditions for the system, ensuring the criteria developed provide satisfactory security performance for the most severe conditions experienced under actual expected system operations.

The conditions for each of the planning years were determined based on the forecast amount of variable generation added to the system, retirement of existing units, and/or the addition of new generating units. Not all years were studied. If there were no significant deviations from year-to-year, the results from the years on either end of the quiescent period were assumed applicable to the years not studied.

For each year selected, a unit commitment schedule was developed that resulted in the minimum number of conventional units being operated and the maximum use of variable generation. The largest contingency, whether it resulted from the use of conventional generation or variable generation, was tripped offline at full load. The results were analyzed and "fast-acting" energy storage was added until acceptable performance was achieved. This process was repeated for all selected years.

For systems with high availability of wind, new wind resources were compared to energy storage systems to determine if curtailed wind resources could provide the desired characteristics of energy storage systems.

The results for all of the islands are very similar. In the near term, it is difficult or infeasible to meet the planning criteria for existing conditions. With existing DG-PV characteristics, each system collapses (that is, island-wide blackout) for a number of different conditions. All three systems could also experience a system collapse for transmission faults unless cleared in less than 9–11 cycles. The Hawaiian Electric system is vulnerable to collapse following the loss of the largest single contingency.

In the immediate future, the retrofits of control features to DG-PV installations are essential to mitigating the chance of system collapse for these events. The DG-PV must be retrofitted to the ride-through standards in the proposed changes to Rule 14H. It is assumed that most of the DG-PV can be retrofitted with only a small amount on each legacy system that cannot be retrofitted.

Another immediate improvement is to decrease the time required to reliably detect and clear faults on the systems' transmission lines. Historically, a fault could be present on the system for 18–21 cycles (0.30–0.35 seconds) in almost all systems. Today, for faults that exist longer than 9–11 cycles (0.15–0.18 seconds), the faults can result in a total system collapse. This time is referred to as the "critical clearing time" for the respective power system. Critical clearing times less than 18 cycles require the use of communications assisted relaying on all transmission terminals.

As the amount of variable generation increases, the critical clearing time will continue to decrease and the rate of frequency collapse will continue to increase. It was therefore assumed that retrofitting of the DG-PV would be completed prior to 2015, and the installation of improved relay and communications systems would be completed prior to 2016. It was assumed that the first year any new variable energy resources could be added to any system is 2017.

To mitigate the number of customers impacted by such contingencies and improve system security, the UFLS should be upgraded to recognize a system contingency and its characteristics. For instance, as the amount of DG-PV continues to increase, the amount of load controlled by each stage and the effectiveness of the UFLS will correspondingly degrade. In order to prevent frequency excursions into the regions that place the entire system at risk of collapse, more feeder breakers need to be activated at Stage 1 of the UFLS. This would result in the loss of more customers for Stage 1 events than historically experienced. However, in the evening when the DG-PV and PV is not producing, the operation of these additional breakers in Stage 1 would result in shedding more load than is necessary, producing an over frequency condition that could also place the system at a high risk. The load shedding system needs to be adaptive and dynamic. It needs to be able to activate the correct amount of breakers to cover the contingency and minimize the number of customers whose service is interrupted. An adaptive load shedding system is assumed to be operational at all three major utilities prior to 2016.

Hawaiian Electric: Years 2015–2016

The amount of DG-PV that cannot be retrofitted to the meet the proposed ride-through settings is critical for the security of the power system. The existing amount of DG-PV tripping for original standard IEEE 1547 trip settings on the Hawaiian Electric system is estimated to be 70 MW. With 70 MW of legacy DG-PV, the system cannot survive the largest contingency. As the legacy DG-PV is reduced, the system response improves. The maximum amount of legacy DG-PV is recommended to be no more than 40 MW. This level of legacy DG-PV still results in significant load shedding and violations of TPL-001, however, the power system would be more resistant to collapse.

Legacy DG-PV also impacts the over frequency performance of the power system, since the legacy DG-PV currently trips offline at 60.5 Hz. The loss of 250+ MW of legacy DG-PV results in the collapse of the Hawaiian Electric system. The reduction in the amount of legacy DG-PV that trips at 60.5 Hz is also recommended to be reduced to less than 40 MW.

In 2015, aside from modification of DG-PV settings to provide ride-through, options are limited to only changes in system operations, protective relaying, and communications improvements. A transfer trip scheme between AES, Kahe 5, Kahe 6, and the UFLS breakers can help prevent, in some instances, one stage of load shedding for the loss of one of the larger units. Reducing the maximum output of AES is the only other mitigation strategy that was identified as feasible for 2015.

By the end of 2016, approximately 286 MW of utility-scale PV is expected to be installed on the power system. While this PV forces other generation offline and further decreasing the system inertia, it also has the potential to supply fast-acting contingency reserve through curtailed energy. Without curtailment and additional contingency reserve, the displacement of the thermal unit by the station PV cannot be mitigated. The additional contingency reserve could be supplied by energy storage.

In 2017, the system requires 200 MW of contingency reserve to meet the requirements of TPL-001. It should be noted that due to the extremely fast frequency decay associated with the sudden trip of a large generator, the contingency reserve must be provided by systems other than thermal generation (such as fast acting storage or other similarly fast responding device). Following the installation of the contingency reserve, the system can operate with few system constraints providing faults meet the critical clearing time. Although simulations to assess the system stability with as few as two firm (and dispatchable) units were completed, this was done only to assess the stability of the system during a boundary condition. System operating considerations would preclude operation with fewer than three dispatchable units.

Following the installation of 200 MW of contingency reserve in 2017 (for example, energy storage), additional contingency reserve may be required if additional variable generation is added and the single largest contingency remains at 180 MW (that is, AES).

The system security constraints are summarized in Table 4-4 through Table 4-7 for Hawaiian Electric. The Thermal Units Required column specifies the minimum number of thermal units required for stability. The remaining columns designate the specific constraint.

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve	Voltage Support (SVC)
2017 200 MW AES Trip								
Station PV	272	4	86.6 MW/min	281 MW (20% of DG-PV + 35% Station PV + 50% Wind)	62 MW (50% Wind)	200 MW	200 MW	±80 MVAr
DG-PV	471							
Wind	123							
Largest Unit	200							
2017 100 MW AES Trip								
Station PV	272	4	86.6 MW/min	281 MW (20% of DG-PV + 35% Station PV + 50% Wind)	62 MW (50% Wind)	100 MW	100 MW	±80 MVAr
DG-PV	471							
Wind	123							
Largest Unit	200							

Table 4-4. Hawaiian Electric 2017 System Security Constraints

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve	Voltage Support (SVC)
2022 AES + LM6000 Units								
Station PV	272	3: AES + 2 LM6000	95.1 MW/min	311 MW (20% of DG-PV + 35% Station PV + 50% Wind)	62 MW (50% Wind)	100 MW	100 MW	±80 MVAr
DG-PV	556							
Wind	123							
Largest Unit	100							
2022 AES + LMS100 Units								
Station PV	272	2: AES +1 LMS100	95.1 MW/min	311 MW (20% of DG-PV + 35% Station PV + 50% Wind)	62 MW (50% Wind)	100 MW	100 MW	±80 MVAr
DG-PV	556							
Wind	123							
Largest Unit	100							

Table 4-5. Hawaiian Electric 2022 System Security Constraints

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve	Voltage Support (SVC)
2030 LM6000 Units								
Station PV	272	7	95.1 MW/min	337 MW (20% of DG-PV + 35% Station PV + 50% Wind)	62 MW (50% Wind)	60 MW	100 MW	±80 MVAr
DG-PV	631							
Wind	123							
Largest Unit	100							
2030 LMS100 Units								
Station PV	272	5	95.1 MW/min	337 MW (20% of DG-PV + 35% Station PV + 50% Wind)	62 MW (50% Wind)	60 MW	100 MW	±80 MVAr
DG-PV	631							
Wind	123							
Largest Unit	100							

Table 4-6. Hawaiian Electric 2030 System Security Constraints

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve	Voltage Support (SVC)
2030 Minimum LM6000 Units; 60 MW BESS								
Station PV	272	3	95.1 MW/min	337 MW (20% of DG-PV + 35% Station PV + 50% Wind)	62 MW (50% Wind)	100 MW	100 MW	±80 MVAr
DG-PV	631							
Wind	123							
Largest Unit	100							
2030 Minimum LMS100 Units; 60 MW BESS								
Station PV	272	2	95.1 MW/min	337 MW (20% of DG-PV + 35% Station PV + 50% Wind)	62 MW (50% Wind)	100 MW	100 MW	±80 MVAr
DG-PV	631							
Wind	123							
Largest Unit	100							

Table 4-7. Hawaiian Electric 2030 System Security Constraints with 60 MW BESS

Hawai‘i Electric Light: Years 2015–2016

The Hawai‘i Electric Light system was one of the first island systems to revise the tripping points of the DG-PV systems from 59.3 Hz to 57.0 Hz. Consequently, they have a smaller percentage of DG-PV that trips at 59.3 Hz on the power system as compared to the other islands. However, all of the DG-PV has over frequency trip points of 60.5 Hz. Due to this condition, fault durations longer than 9 cycles result in the potential for system collapse in simulations.

Simulations for years 2015–2016 assumed improvements to protective relaying and communications were in service. Direct transfer tripping of system load following the loss of the largest contingency is recommended to mitigate the number of customers impacted by single contingency events.

Hawai'i Electric Light: Years 2017–2030

The security of the Hawai'i Electric Light system requires the addition of contingency reserve and additional regulating reserve in 2017 as the level of DG-PV increases. The regulating reserve can be supplied by either thermal units, energy storage units, curtailed wind, curtailed solar, or controlled load.

Although simulations to assess the system stability with as few as two firm (and dispatchable) units were completed, this only assessed the stability of the system during a boundary condition. System operating considerations would preclude operation with fewer than three firm (and dispatchable) facilities under automatic generation control. The assessment assumed typical dispatchable PGV, Hu Honua, and Keahole Combined Cycle (single train).

The system security constraints are summarized in Table 4-8 through Table 4-10 for Hawai'i Electric Light. The Thermal Units Required column specifies the minimum number of thermal units required for stability. The remaining columns designate the specific constraint.

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve
2015 Security Constraints							
PV Level	56	3	9.6 MW/min	27 MW maximum	16 MW maximum	31 MW	27 MW
Thermal Units	3 online						
2016 Security Constraints							
PV Level	67	3	10.9 MW/min	29 MW maximum	16 MW maximum	29 MW	27 MW
Thermal Units	3 online						

Table 4-8. Hawai'i Electric Light 2015–2016 System Security Constraint

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve
2019 Scenario 1 Security Constraints							
PV Level	78	2	12.2 MW/min	32 MW maximum	16 MW maximum	20 MW	22 MW
Thermal Units	2 online						
PV Level	78	3	12.2 MW/min	32 MW maximum	16 MW maximum	20 MW	25 MW
Thermal Units	3 online						
2025 Scenario 2 Security Constraints							
PV Level	89	2	13.6 MW/min	34 MW maximum	16 MW maximum	25 MW	25 MW
Thermal Units	2 online						
PV Level	89	3	13.6 MW/min	34 MW maximum	16 MW maximum	20 MW	25 MW
Thermal Units	3 online						
2025 Scenario 3 Security Constraints							
PV Level	89	2	14.6 MW/min	21 MW maximum	3 MW maximum	25 MW	22 MW
Thermal Units	2 online						
PV Level	89	3	14.6 MW/min	21 MW maximum	3 MW maximum	20 MW	25 MW
Thermal Units	3 online						
2025 Scenario 4 Security Constraints							
PV Level	89	2	17.6 MW/min	54 MW maximum	36 MW maximum	25 MW	22 MW
Thermal Units	2 online						
PV Level	89	3	17.6 MW/min	54 MW maximum	36 MW maximum	20 MW	25 MW
Thermal Units	3 online						

Table 4-9. Hawaiʻi Electric Light 2019–2025 Scenarios System Security Constraints

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve
2030 Scenario 1 Security Constraints							
PV Level	97	2	14.5 MW/min	35 MW maximum	16 MW maximum	20 MW	22 MW
Thermal Units	2 online						
PV Level	97	3	14.5 MW/min	35 MW maximum	16 MW maximum	20 MW	25 MW
Thermal Units	3 online						
2030 Scenario 2 Security Constraints							
PV Level	97	2	14.5 MW/min	35 MW maximum	16 MW maximum	25 MW	25 MW
Thermal Units	2 online						
PV Level	97	3	14.5 MW/min	35 MW maximum	16 MW maximum	20 MW	25 MW
Thermal Units	3 online						
2030 Scenario 3 Security Constraints							
PV Level	97	2	15.5 MW/min	23 MW maximum	3 MW maximum	25 MW	22 MW
Thermal Units	2 online						
PV Level	97	3	15.5 MW/min	23 MW maximum	3 MW maximum	20 MW	25 MW
Thermal Units	3 online						
2030 Scenario 4 Security Constraints							
PV Level	97	2	18.5 MW/min	55 MW maximum	36 MW maximum	25 MW	22 MW
Thermal Units	2 online						
PV Level	97	3	18.5 MW/min	55 MW maximum	36 MW maximum	20 MW	25 MW
Thermal Units	3 online						

Table 4-10. Hawai'i Electric Light 2030 Scenarios System Security Constraints

Maui Electric

The amount of legacy DG-PV on the Maui Electric system on Maui Island should not exceed 10 MW. Quantities in excess of 10 MW can result in excessive load shedding and the potential for system collapse. Improved relaying and communications are assumed to be installed in 2015 to help mitigate the potential for this consequence.

Maui Electric currently has two BESS connected to its system, one at Kaheawa Two and one at the Auwahi wind generating facilities. One BESS currently only manages the ramp rate of its associated wind generating facility, and the other has 10 MW of reserve available for the Maui Electric system. Years 2017 and 2019 represent significant changes to the Maui Electric system with the addition of substantial amounts of DG-PV and the permanent retirement of the four generating units at Kahului Power Plant.

The system security study for Maui Electric identified the energy requirements for the south Maui system to operate without the construction of new transmission lines to the area.

The system security constraints for Maui Electric are summarized Table 4-11 through Table 4-14. The Thermal Units Required column specifies the minimum number of thermal units required for stability. The remaining columns designate the specific constraint.

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve	DTT Scheme§ Required
Minimum Thermal Units, No EES								
Wind	72	DTCC1 + KPP3, KPP4	12.5 MW	47.25 MW	36 MW	24 MW	40.2 MW	Yes
DG-PV	75							
Largest Unit	30							
Wind	72	DTCC1 + ½ DTCC2 KPP3, KPP4	12.5 MW	47.25 MW	36 MW	45 MW	40.2 MW	No
DG-PV	75							
Largest Unit	30							

§ DTT Scheme refers to a direct transfer trip of the first stage of load shedding for select unit outages. In order to prevent the tripping of the second stage of load shedding, the first stage should be transfer tripped for the loss of the KWP plant or any of the combustion turbines.

Table 4-11. Maui Electric 2015 System Security Constraints

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve	DTT Scheme§ Required
Minimum Thermal Units, No EES								
Wind	72	DTCC1 + KPP3, KPP4	14 MW	49.5 MW	36 MW	45 MW	40.2 MW	No
DG-PV	90							
Largest Unit	30							

§ DTT Scheme refers to a direct transfer trip of the first stage of load shedding for select unit outages.

Table 4-12. Maui Electric 2016 System Security Constraints

The security constraints for years after 2016 (Table 4-13 and Table 4-14) assume that the utility will have the capability to install an energy storage system to meet the criteria.

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve
Minimum Thermal Units, Maximum EES							
Wind	72	DTCC1	14.6 MW	50.4 MW	36 MW	25 MW	38.5 MW
DG-PV	96						
Largest Unit	30						
Wind	72	DTCC1 + ½ DTCC2§	14.6 MW	50.4 MW	36 MW	10 MW	38.5 MW
DG-PV	96						
Largest Unit	30						
Wind	72	DTCC1 + KPP3, KPP4	14.6 MW	50.4 MW	36 MW	10 MW	38.5 MW
DG-PV	96						
Largest Unit	30						
Wind	72	DTCC1 + ½ DTCC2 KPP3, KPP4	14.6 MW	50.4 MW	36 MW	0 MW	38.5 MW
DG-PV	96						
Largest Unit	30						

§ The DTCC1 + ½ DTCC2 minimum unit combination closely matches the 2019 daytime cases since the load increase during the day is offset by the increase in the solar capacity For this reason, 2019 cases were not run.

Table 4-13. Maui Electric 2017 System Security Constraints

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve	Transmission Constraint§
Baseline: Minimum Thermal Units, Maximum EES								
Wind	72	DTCC1	18 MW	55.5 MW	36 MW	25 MW	38.5 MW	No
DG-PV	130							
Largest Unit	30							
Wind	72	DTCC1 + ½ DTCC2	18 MW	55.5 MW	36 MW	20 MW	38.5 MW	No
DG-PV	130							
Largest Unit	30							
NTA-PSH Minimum Thermal Units, Maximum EES								
Wind	72	DTCC1	18 MW	55.5 MW	36 MW	25 MW	38.5 MW	Yes
DG-PV	130							
Largest Unit	30							
Wind	72	DTCC1 + ½ DTCC2	18 MW	55.5 MW	36 MW	10 MW	38.5 MW	Yes
DG-PV	130							
Largest Unit	30							
NTA ICE Minimum Thermal Units, Maximum EES								
Wind	72	DTCC1	18 MW	55.5 MW	36 MW	25 MW	38.5 MW	Yes
DG-PV	130							
Largest Unit	30							
Wind	72	DTCC1 + ½ DTCC2	18 MW	55.5 MW	36 MW	10 MW	38.5 MW	Yes
DG-PV	130							
Largest Unit	30							

1. With the proposed transmission upgrades, the generation dispatch is not constrained by transmission.
2. With a 30 MW PSH located in South Maui, all transmission constraints can be relieved. Minimum frequency for unit trip events are slightly lower compared to the same contingencies with the proposed ICE units located in South Maui.
3. With a 24 MW of ICE units located in South Maui, all transmission constraints can be relieved. Minimum frequency for unit trip events is slightly better compared to the same contingencies with the proposed PSH unit located in South Maui. The difference in response between the PSH and ICE units does not warrant a change in the contingency reserve requirements.

Table 4-14. Maui Electric 2030 System Security Constraints

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5. Preferred Plan

Hawai‘i Electric Light developed this Preferred Plan for transforming the system from current state to a future vision of the utility in 2030 that is consistent with the Strategic Direction (presented in Chapter 2).

Implementation of this Preferred Plan would safely transform the electric system and achieve unprecedented levels of renewable energy production. The electric system of the future would be a balanced portfolio of renewable energy resources, thermal generation, energy storage, and demand response.

This Preferred Plan transforms the electric system to provide the appropriate characteristics to accommodate high levels of both variable and dispatchable renewable technologies. This transformation includes the addition of new renewable dispatchable generating units and energy storage for system reliability. The plans also incorporate systematic retirement of existing steam generating units as their value to the system has diminished. This transformation allows for the incorporation of significantly unprecedented amounts of renewable generation on the power system, above the levels that are already the highest in the nation. Through adding the identified resources to the power system, the Hawai‘i Electric Light Preferred Plan exceeds the mandated RPS in 2030 by a substantial margin, decreases reliance on imported fossil fuels, improves costs, and preserves system operability.

The tactical, year-by-year plan for executing this transformation is described and discussed in this chapter.

HAWAI'I ELECTRIC LIGHT OF 2030: UNPRECEDENTED LEVELS OF RENEWABLE ENERGY

The Hawaiian Electric Companies are at the forefront of defining and designing the electric utility industry of the future. Our task is especially challenging. We are blessed with immense renewable resources, but each island has different situations and opportunities. Our island grids operate without interconnections and therefore we cannot share reliability responsibilities with other systems. Due to the small size of the autonomous island grids, variable generation creates significant challenges to system operation. Nevertheless, we are transforming our power supply portfolio to employ unprecedented levels of renewable resources while continuing to provide reliable and safe electric service to all customers at a reasonable cost.

The vision does not focus on one strategic element to the detriment of another, but rather focuses on satisfying multiple considerations. These considerations include:

- Social Policy. Efforts to "go green", address customer choice, sustainability, manage or lower costs, and maintain flexibility. These objectives often move in opposing directions so the plans must balance these competing priorities.
- Consideration of Myriad of Technology Options. There are a large number of both renewable, demand side, storage, transmission and distribution, and fossil technology options that could be incorporated. This creates a large number of possibilities as to technology mix; conversely there are very concrete requirements for maintaining grid safety and security.
- Rate Impacts. Transformation from current state to preferred state will involve extensive capital expenditures and managing risk. Capital investments are required to acquire new renewable resources and convert existing resources to alternate fuels, to lower fuel costs in the long run. The impact on customer bills has to be considered in the choice of technology options and the path to realizing the long-term vision embodied in energy policies.
- Increased Customer Choice. Incorporates distributed assets as well as centralized assets into the grid system control center. This migration to a system control which has integrated distributed assets into the overall grid management actively increases customer participation and choice.
- Third Party Participation. Continue to expand third party participation in production and ancillary services; raising required capital will extend beyond Hawai'i Electric Light and will require participation of independent power producers and other third parties.
- Integration of Variable Resources. Rich renewable resources are variable and do not provide the same ancillary services and system security capabilities as thermal

resources. The resource plan must address these differences in order to maintain system reliability and security. This is achieved by a combination of available solutions: addition of technologies such as storage and demand response, increased contribution to grid reliability from thermal resources and dispatchable renewable resources, and technical and operational requirements for the variable resources to improve their impact on grid reliability.

- Fuel Prices. Hedge against fuel price escalation and uncertainty; while sustainability goals are high and going green is complex, it offers a natural hedge against fuel price escalation.

To this end, the vision of Hawai‘i Electric Light in 2030 includes transforming the system design to maintain system operability, provide acceptable levels of system security, and incorporate more renewable energy and decreasing reliance on imported fossil fuels.

The Preferred Plans for the Hawaiian Electric Companies will result in significantly exceeding the Renewable Portfolio Standard (RPS) requirement of 40% by 2030 at each operating company.

Company	Renewable Portfolio Standard
Hawaiian Electric	61%
Maui Electric	72%
Hawai‘i Electric Light	92%
Consolidated	67%

Table 5-1. 2030 Renewable Portfolio Standard Percentages for Preferred Plans

Projection of Compliance with the Renewable Portfolio Standard

As shown in Figure 5-1, the Hawaiian Electric Companies' Preferred Plans will add significantly more renewable energy and substantially exceed the mandated Consolidated 2030 RPS of 40%. This Consolidated RPS would be 67%, and would more than double between 2015 and 2030.

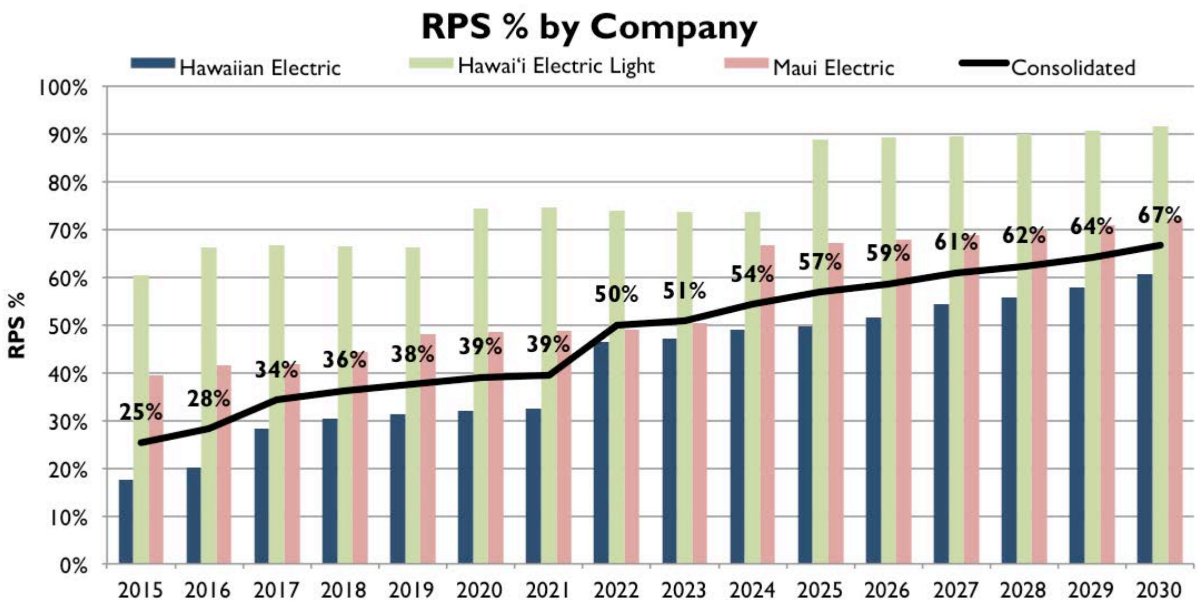

Figure 5-1. Consolidated RPS of Hawaiian Electric Companies' Preferred Plans

The Hawai'i Electric Light Preferred Plan for Hawai'i Island increases the RPS to 92% by year 2030 (Figure 5-3 below). The relative contribution of distributed generation photovoltaic (DG-PV, also referred to as "rooftop PV") will be a significant portion of the RPS value.

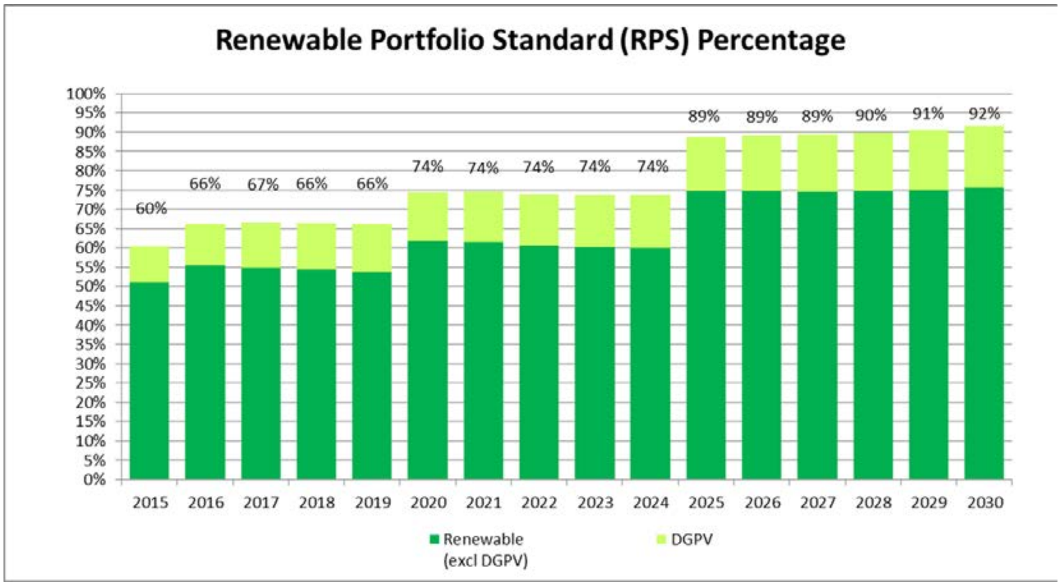

Figure 5-2. Hawai'i Electric Light Preferred Plan RPS

The mix of renewable energy resources contributing to the RPS in 2030 is shown in Figure 5-4 (the chart does not show the fossil fuel resources). Note the very substantial contribution of geothermal resources, which is unique to Hawai'i Island.

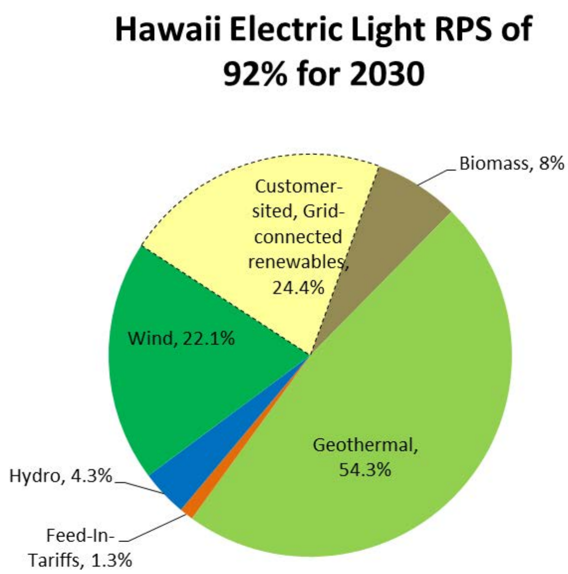

Figure 5-3. Source of Renewable Energy used in the 2030 RPS for Hawai'i Electric Light Preferred Plan

As described in Chapter 2, the Companies developed Power Supply Improvement Plans in two iterative steps:

A. Step A: Define the desired end state for the physical design of the power system in 2030

B. Step B: Define and validate a detailed path to transform from the current state to the desired end state in 2030

In Step B, Hawai'i Electric Light developed this Preferred Plan through a collaborative, analytical, and innovative process. The PSIP analytics leveraged different models and modeling teams. The Preferred Plans were developed to assure safe operability and reliability consistent with the system security analysis described in Chapter 4.

The process began with the construction of a Base Plan, then various sensitivity analyses were performed to gain insights on the impacts of the alternatives to the Base Plan. Collaboration between the teams proved invaluable in providing opportunities for sharing theories and options for improvement based on incremental analytical results. Using different models, and performing sub-hourly analysis, was a means for vetting the results obtained, as discussed in Appendix L. Those alternatives that displayed positive cost and resource diversity impacts to the Base Plan were candidates for incorporation into the Preferred Plan.

The resulting Preferred Plan was tested to assure system operability, reliability, and stability, and financial outputs were then forwarded to the Financial Model for further analysis. Figure 5-4 illustrates the sensitivities analyzed and the evolution into the Preferred Plan. Figure 5-5 shows a timeline out to 2030 of the Preferred Plan, and it shows when new resources would be added ("above the date line") and existing resources would be retired ("below the date line").

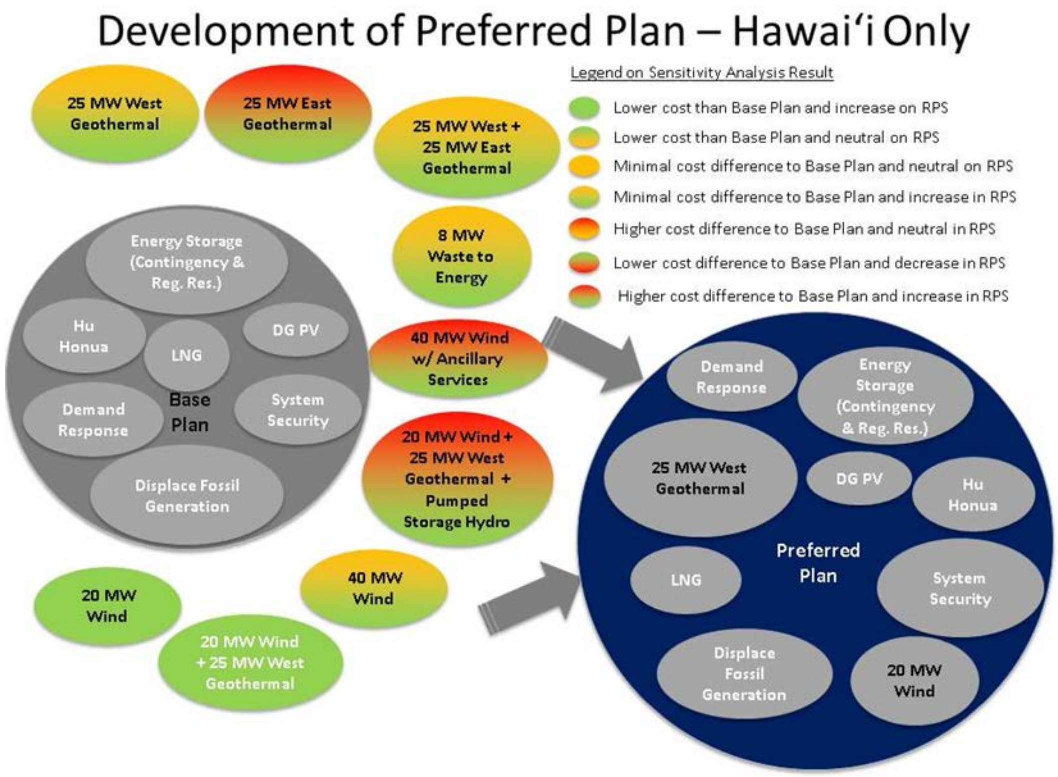

Figure 5-4. Illustration of the Process for Developing the Hawai'i Electric Light Preferred Plan

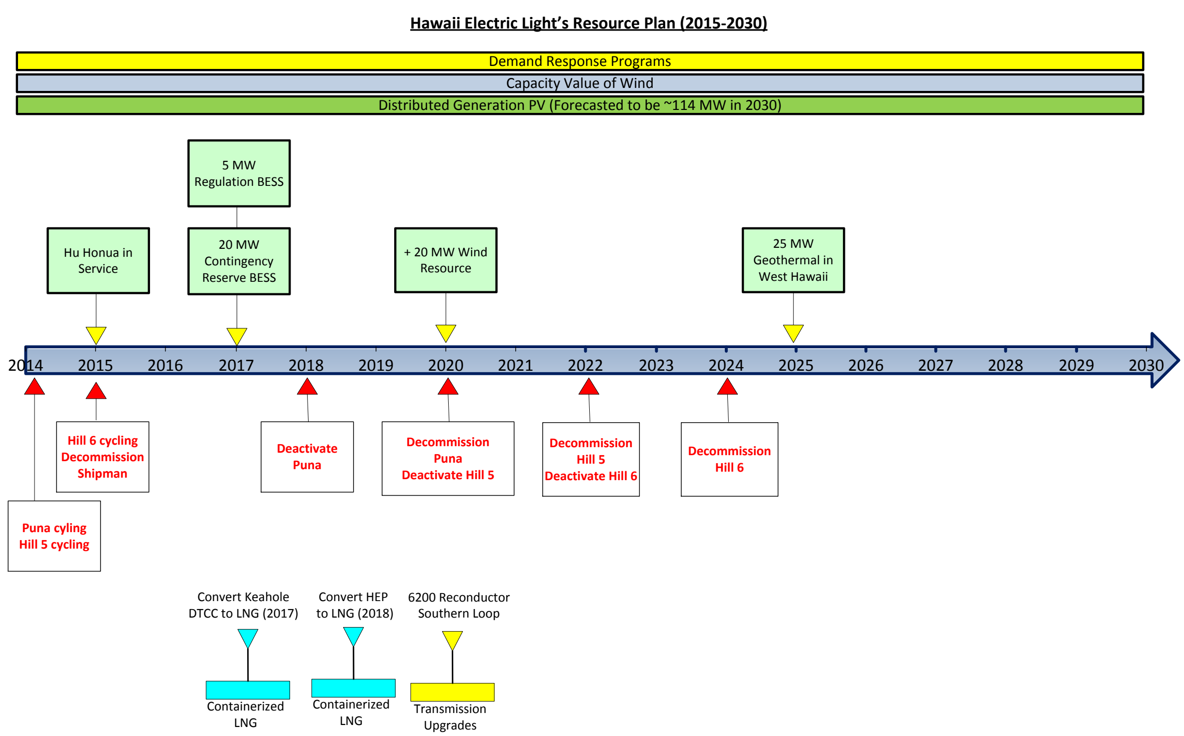

Figure 5-5. Timeline Diagram of Hawai'i Electric Light Preferred Plan

GENERATION RESOURCE CONFIGURATION

The transformation of the electric system design allows for incorporating additional low-cost renewable energy on the Hawai'i Electric Light power system. The plan also leverages conversion to lower-cost LNG to replace oil in thermal generation. To accomplish this, the location and technical and operational characteristics are considered in selection of new resources. This transformation from reliance upon fossil fuels to renewable energy has been continuously occurring with innovative renewable generation resources, and technical and operational changes for thermal resources. The Preferred Plan incorporates additional renewable resources: growing distributed PV (DG-PV), new low-cost wind, and new dispatchable geothermal generation—all of which permits additional displacement of energy from fossil fuels. As need for the energy and capacity from steam units declines due to benefits of new resources and changes in load demand, the generators are planned for retirement. Thermal units providing significant amounts of energy are converted from oil to lower-cost LNG.

Transformational change is needed to reliably operate the system with the amounts of distributed and variable renewable energy included in the plan. The system must incorporate significant amounts of energy storage. Modification is required of the system's relay protection equipment and underfrequency load shed schemes. Changes are required to substation components and communication equipment to meet more stringent and shorter clearing times. Each increment of variable generation has to be balanced by dispatchable firm generation assets (fossil or renewable) and/or energy storage to meet various system reliability criteria. The plans also include Demand Response, including impacts of time-of-use rates, reduction in peak, and contribution to system security requirements.

Changes that allow for higher levels of variable renewable penetration onto the electrical system incur costs. For example, operating generating units at lower, less-efficient load levels to manage the regulating reserve requirements that increase as more variable renewable resources are added to the system increase costs. The lower output of the firm, dispatchable assets results in less efficient operations of these assets (similar to a cars gas mileage is worse at 10 mph than at 50 mph). Additional starts and stops caused by variable generation resources are expected to increase maintenance costs for these assets. These and other considerations were considered in cost analysis for the development of the Preferred Plan, in addition to the leveled cost of a resource technology. This includes valuing the capabilities of dispatchable renewable energy, which can contribute to system security and reliability through the operational and technical characteristics. The full process for the development of the Preferred Plan is described in more detail in Appendix L.

Energy Mix

The Hawai'i Electric Light Preferred Plan will change over time to convert thermal units to LNG and incorporate greater amounts of renewable energy future in 2030. Figure 5-6 shows how the resource mix of generation transforms over time.

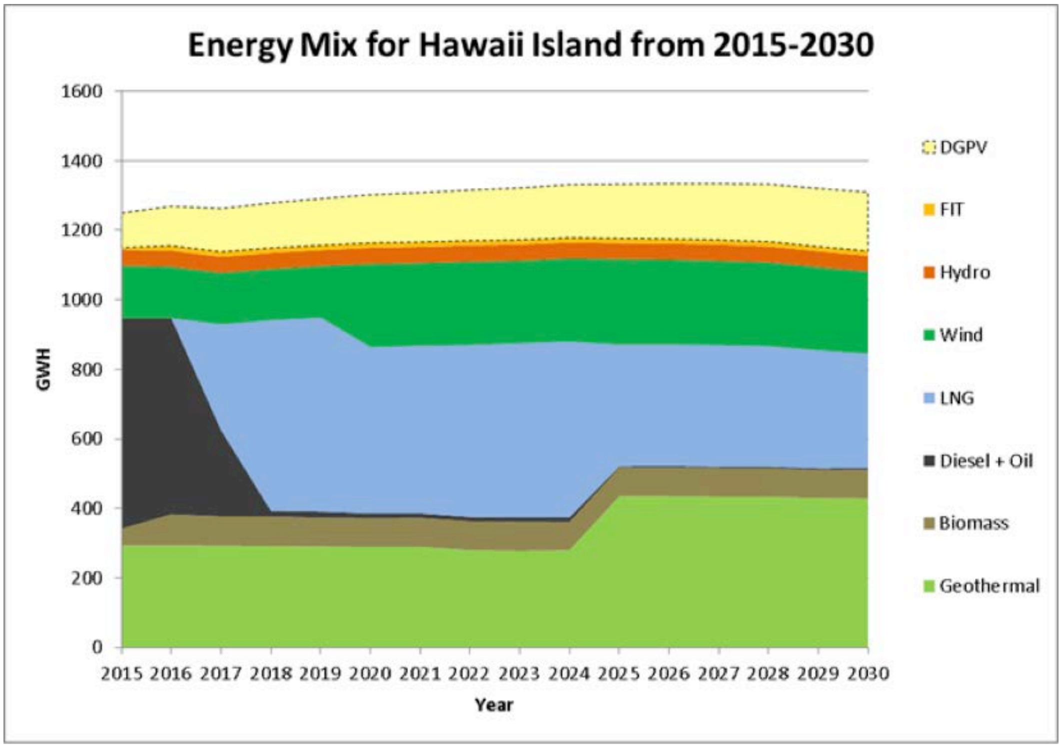

Figure 5-6. Annual Energy Mix of Hawai'i Electric Light Preferred Plan

Generation Resources for the Preferred Plan ("X" indicates resources included)																
Unit	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
DG PV	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
FIT	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Tawhiri Wind	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
HRD Wind	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Wailuku Hydro	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Utility Hydro	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Future Wind						X	X	X	X	X	X	X	X	X	X	X
20 MW BESS (Contingency)			X	X	X	X	X	X	X	X	X	X	X	X	X	X
5 MW BESS (Regulation)			X	X	X	X	X	X	X	X	X	X	X	X	X	X
PGV	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
HEP	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Hu Honua	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Hill 5	X	X	X	X	X	Deactivated		Decommissioned								
Hill 6	X	X	X	X	X	X	X	Deactivated		Decommissioned						
Puna	X	X	X	Deactivated		Decommissioned										
Kanoe D11	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Waime D12	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Waime D13	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Waime D14	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Kanoe D15	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Kanoe D16	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Kanoe D17	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Keaho D21	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Keaho D22	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Keaho D23	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Kanoe CT1	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Keaho CT2	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Keaho CT4	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Keaho CT5	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Keaho ST7	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Puna CT3	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Panaewa	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Ouli	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Punalu'u	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Kapua	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Future West Geothermal											X	X	X	X	X	X

Table 5-2. Hawai'i Electric Light Preferred Plan Generation Resources

The chart (above) shows the generation resources in the preferred plan for each year from 2014 to 2030.

Adequacy of Power

Our first priority is providing safe and reliable service for our customers, and this starts with planning to maintain an adequate amount of capacity to meet our customers' needs. Hawai'i Electric Light's Preferred Plan complies with current capacity planning criteria[28], as well as draft planning criteria, BAL-502, provided in Appendix M. The draft planning criteria in BAL-502 includes the capacity value of demand response, grid-side variable renewable generation, and energy storage. The impact of dynamic pricing on the evening peak is incorporated into the margin analysis.[29] For the purposes of the PSIP, a minimum of 30% reserve margin was targeted. Table 5-3 shows the resulting reserve margin for the Preferred Plan.

[28] Docket No. 2012-0036, Integrated Resource Planning, Appendix L: Capacity Planning Criteria.

[29] For more details refer to the Companies' *Integrated Demand Response Portfolio Plan* (IDRPP) filed with the Commission on July 26, 2014.

Hawaii Electric Light Preferred Plan										Revisions as of August 23, 2014		
Year	Peak (MW)	Total Thermal Capacity (MW)	New Thermal Generation (MW)	Deactivated (MW)	DR for Capacity (MW)	Energy Storage for Capacity (MW)	Variable Generation Capacity (MW)	Notes	Reserve Margin (%) Base	Reserve Margin (%) w/ DR	Reserve Margin (%) w/ Energy Storage	Reserve Margin (%) w/ Variable GenerationCapacity Value
Included in Reserve Margin Calculation								Thermal Generation	x	x	x	x
								Demand Response		x	x	x
								Energy Storage			x	x
								Capacity Value of Wind				x
2014	191	275	0.0	0.0	0.0	0	3.8		44.4%	44.4%	44.4%	46.4%
2015	190	297	21.5	0.0	0.3	0	3.8	Add Hu Honua	56.2%	56.5%	56.5%	58.5%
2016	188	297	0.0	0.0	4.1	0	3.8		57.7%	61.2%	61.2%	63.3%
2017	175	297	0.0	0.0	4.9	0	3.8		69.3%	74.1%	74.1%	76.4%
2018	177	281	0.0	(15.7)	5.6	0	3.8	Deactivate Puna	58.6%	63.8%	63.8%	66.0%
2019	179	281	0.0	0.0	6.4	0	3.8		57.1%	63.0%	63.0%	65.2%
2020	180	287	20.0	(13.5)	7.2	0	5.8	Add 20 MW Wind Deactivate Hill 5	59.4%	66.0%	66.0%	69.4%
2021	181	287	0.0	0.0	7.2	0	5.8		58.6%	65.2%	65.2%	68.5%
2022	183	267	0.0	(20.2)	7.2	0	5.8	Deactivate Hill 6	46.2%	52.2%	52.2%	55.5%
2023	183	267	0.0	0.0	7.2	0	5.8		45.9%	51.8%	51.8%	55.1%
2024	183	267	0.0	0.0	7.2	0	5.8		45.6%	51.6%	51.6%	54.9%
2025	184	292	25.0	0.0	7.2	0	5.8	Add 25 MW Geothermal	58.5%	65.0%	65.0%	68.3%
2026	183	292	0.0	0.0	7.2	0	5.8		59.5%	66.1%	66.1%	69.4%
2027	182	292	0.0	0.0	7.2	0	5.8		60.5%	67.2%	67.2%	70.5%
2028	181	292	0.0	0.0	7.2	0	5.8		61.6%	68.3%	68.3%	71.6%
2029	180	292	0.0	0.0	7.2	0	5.8		62.6%	69.4%	69.4%	72.7%
2030	179	292	0.0	0.0	7.2	0	5.8		63.6%	70.5%	70.5%	73.9%

Table 5-3. Reserve Margin for the Hawaiʻi Electric Light Preferred Plan

Capacity Value of Variable Generation and Demand Response

Accurately assessing the capacity value of variable generation and demand response resources are critical components toward meeting customer demand and maintaining system reliability.

Capacity Value of Variable Generation

Wind was assigned a capacity value of 10% of nameplate capacity. This 10% capacity value was determined using a statistical correlation of variable generation output during the peak hour of each day. A 90% probability level was used to determine the capacity value. For the purposes of the impact of a new wind facility on capacity requirements, it was assumed to provide 10% capacity similar to the existing facilities.

PV was not assigned any capacity value due to the annual peak of the system occurring in the evening when PV is not available.

Run-of-river hydro was assigned a capacity value of about 4% of nameplate capacity. This value was determined using a statistical correlation of variable generation output during the peak hour of each day. A 90% probability level was used to determine the capacity value.

Capacity Value of Demand Response

The demand response programs defined in the *Integrated Demand Response Portfolio Plan* (IDRPP)[30] that are expected to provide capacity value are included in the calculation for the reserve margin; time-of-use rates are assumed to substantially reduce the peak demand. (See Appendix F for details on the assumptions used in the PSIP for demand response.)

System Reliability

To move to a future with substantial variable renewable energy, the physical design of the system must be able to operate safely and reliably with the resources available. The criteria and requirements for developing a plan to adequately accomplish this was described, in part, in Chapter 4. All the generation and transmission planning criteria are met to achieve the unprecedented levels of RPS in the Preferred Plan.

ROLES OF GENERATION RESOURCES

The current state of the electrical grid has transformed into one where variable renewable resources, particularly distributed solar, has changed the system reliability requirements that Hawaiʻi Electric Light; Independent Power Producers need to adapt to, in order to continue to provide safe, reliable power to all customers. The existing generation fleet of on Hawaiʻi Island is comprised of utility and Independent Power Producer (IPP) firm capacity resources that have provided system security and safe, reliable power for many years. The mix of resources must also provide adequacy of energy supply, as addressed through resource adequacy evaluations.

The operation of the firm generation resource mix is expected to change over time to utilize lower-cost LNG and incorporate additional firm renewable energy. Adding energy storage, demand response, and requiring firm renewable generation to provide necessary grid support capabilities are necessary components of the Preferred Plan to enable reliable operation with increased variable renewable generation on the electrical system. In addition, the secure operation of the system requires that distributed generation contribute to improved system security by improvements by remaining connected through faults and contingencies, and active power control to manage excess

[30] On July 28, 2014, in Docket No. 2007-0341, the *Integrated Demand Response Portfolio Plan* was filed by the Hawaiian Electric Companies.

energy.[31] The Preferred Plan incorporates measures identified as necessary to mitigate impacts of DG in the April 2014 PSP.

Plan for Increasing Generation Flexibility

Hawai‘i Electric Light has analyzed the operation of existing resources and planned resources. The operational plans incorporate the results of consulting work to evaluate optimization of existing resources, and build upon previous cycling and turn down studies, Electric Power Research Institute (EPRI) publications, and other industry literature. We have taken a holistic approach to operational flexibility and have incorporated into our operational and planning processes procedures and policies enabling generation flexibility. The historical operation of the Hawai‘i Electric Light system included a fleet of fast-start generators; these have been leveraged as flexible resources which have proven invaluable in reliable integration of a large amount of wind and distributed solar PV energy. (See Hawai‘i Electric Light's Generation Flexibility Plan, Exhibit 11 of the April 2014 Filing PSP for details.) In the analysis performed subsequent to the April 2014 filing, and identified as necessary measures in that filing, security and reliability studies identified the need for increasing regulating and contingency reserve requirements of reliable operation of the power system with increasing levels of DG-PV. As part of the preferred plan, energy storage will be added to the mix of resources to provide some of the system flexibility and resiliency in the future.

On/Off Cycling

The operational plans for on/off cycling ("Daily Cycling") have been developed based on thorough economic analysis, as described in the Power Supply Plan (PSP).[32] An input to the analysis is the extensive evaluation that determined the system reliability requirements of the system, when resources historically operated continuously are displaced from the system. The results of the analysis produced minimum criteria for system reliability for generation units. With that information, units not necessary for system security and reliability are subject to economic unit commitment dispatch, with consideration of the incurred daily cycling costs. The present system operation at Hawai‘i Electric Light incorporates routine daily cycling of HEP. Puna Steam is currently cycled on a seasonal basis: left offline with preservation measures for extended periods and brought back on line when needed to ensure adequate capacity. When in operation, Puna may be daily cycled if system conditions permit. Hill 5 will also begin daily cycling in 2014. Hill 6 will begin daily cycling in 2015, following the anticipated operation of Hu Honua.

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[31] For more detail, refer to the *Distributed Generation Interconnection Plan* (DGIP) that the Companies filed with the Commission on August 26, 2014.

[32] Hawai‘i Electric Light filed its Power Supply Plan (PSP) with the Commission on April 21, 2014.

Expanded Turn Down Range

Hawai'i Electric light has already improved the turndown of its steam units to lower loads. Minimum dispatch limits decreased by 3 MW to 5 MW for Hill 5, and 7 MW to 8 MW for Hill 6, respectively, since mid-2012. The minimum turndown for Puna Steam was also reduced significantly to 6 MW, and the unit is subject to daily cycling. The minimum economic dispatch limits for other significant units are 27 MW for Puna Geothermal, and 10 MW for Keahole in single-train (combined cycle), the same limit applies for Hamakua Energy Partners in single-train (which is subject to offline cycling). The regulation limit is 5 MW lower for Puna and 1 MW lower for the combined cycle units. Hu Honua will have a 10 MW minimum economic dispatch limit and 7 MW minimum regulation limit.

Fast-Start Resources

Existing generation resources provide a significant amount of fast-start, fast-ramping capability. The fast-start generating resources include fourteen small diesel units (28.5 MW in total that are available in less than three minutes) and three simple-cycle gas turbines (43.3 MW in total that can come online in under 15 minutes, and ramp at 3 to 4 MW/min). In addition, CT4 or CT5, if not online, can be started in simple cycle.

The existing available capacity for fast-start resources is sufficient to meet the supplemental reserve requirements for the Preferred Plan. An assessment was performed to evaluate the cost-effectiveness of replacing existing fast-start unit capacity with more efficient new resources in Appendix O. The evaluation concluded the existing resources meet the operational needs at a lower cost than if provided through new assets, with consideration of the capital investment for new resources.

Frequency Response, Regulation, and Ramp Rates

Generators and technologies differ in their ability to contribute to essential grid services. Tables providing a summary of technical and operational attributes of existing and potential future resources was provided in the April 2014 Power Supply Plan. In order to best meet system needs for frequency response, regulation, and ramping, new generation additions are required to provide these capabilities to maintain system security and reliability. Moreover, where possible, ramping and regulation capabilities are being improved from existing resources. As part of continuous improvement initiatives, ramp rates were increased for all the steam units respectively, since mid-2012. Increased dispatch range also improves regulation capabilities by allowing a larger contribution of a generator to both up and down reserve. Additional projects to continue to improve generation flexibility can be found in the Power Supply Plan. [33]

As part of its expansion to 38 MW, Puna Geothermal Ventures (PGV) changed its facility characteristics from a passive energy source to one that provides frequency response, voltage response, and dispatch under Automatic Generation Control (AGC). PGV can now contribute to regulating reserves where it previously could not. The Hu Honua facility contract terms also require operational and technical capabilities allowing this rebuilt biomass steam-electric power plant to provide grid services. Incorporating capacities similar to existing plants into new generation facilities allows them to operate in place of existing generation while preserving system security and reliability. In the Preferred Plan, the evaluation of new firm capacity renewable resources assumed these resources would provide the grid services comparable to similarly sized conventional plants. The "West Hawai'i Geothermal" scenario assumes that resource could provide the system reliability requirements presently met by the generating units at Keahole Power Plant, through provision of similar operational and technical capabilities and a location electrically near to Keahole. Future new utility-scale variable generation such as the wind plant included in the Preferred Plan will also be designed to incorporate technical and operational capabilities available in present day wind plants, including inertial response, ramp rate control, frequency response, active power control, and disturbance ride-through.

Due to the impacts of DG-PV, increased contingency response (that is, fast frequency-responding reserves) as well as fast-ramping regulating reserves are required, in addition to ride-through capabilities from DG-PV To meet these needs, a 20 MW energy storage system with response capabilities in excess of generation capabilities will be added to the system to provide contingency reserves. To meet the faster ramping capabilities, the fast ramp capabilities of the existing combustion turbines will be leveraged, and supplemented with a 5 MW energy storage system will be included to provide additional fast ramping and regulation. The sizing of the storage assumed that new DG-PV and a substantial amount of existing DG-PV will provide disturbance ride-through.

Key Generator Utilization Plan

Keahole Combined Cycle Units

The combined cycle units at Keahole are assumed to remain in service, and switch fuels from diesel fuel to LNG in 2017. In addition to being an efficient generator providing low-cost energy, Keahole generating station is a critical component for system reliability

[33] Refer to "Future Projects (Exhibit 11B)" of the Power Supply Plan that Hawai'i Electric Light filed with the Commission on April 21, 2014.

and voltage support for the electrical grid. The station also provides system restoration capabilities

Puna Geothermal Ventures (PGV)

The existing Power Purchase Agreement (PPA) between PGV and Hawai'i Electric Light continues until 2027. Upon the conclusion of the PPA, for the purposes of the PSIP, an extension to the PPA is assumed to be successfully negotiated and approved by the Commission.

Hamakua Energy Partners (HEP)

The existing PPA with HEP continues until 2030. We will investigate a fuel switch from naphtha to LNG at HEP in the 2018 timeframe.

Other Generating Units Owned and Operated by Hawai'i Electric Light

In order to utilize lower-cost fuel, we will convert Puna CT-3 to LNG in the 2017 timeframe. The remaining peaking and cycling units will continue to be used as flexible generation resources.

Other Purchased Power

The following existing Power Purchase Agreements (PPA) expire within the model time frame on the dates noted. Upon the conclusion of the PPA, for the purposes of the PSIP, an extension to the PPA is assumed to be successfully negotiated and approved by the Commission with pricing switch to the representative resource prices consistent with those used in the resource evaluation. Curtailment priorities were assumed unchanged in the evaluation.

- HRD – 2021
- Wailuku River Hydro – 2023
- Tawhiri – 2027

Plan for Retiring Fossil Generation

As shown in Figure 5-5, the Preferred Plan has all the existing steam generating units deactivated by 2022. In general, the units will be decommissioned (retired) two years after deactivation. For example, the Puna steam unit will be deactivated by 2018, and decommissioned in 2020.

The operation of our steam units will be monitored to evaluate its need to continuously operate due to economics or to meet system reliability requirements. As the need for the steam units decline, they will be considered for daily or seasonal cycling. Units that would only be required if major changes to operating conditions occur or if anticipated or existing assets fail to perform as expected may be deactivated. Decommissioning is considered for units in which the potential benefits from keeping the option to return to service no longer justifies the limited expense incurred keeping the equipment in reserve.

Plan for New Generation

To create a truly flexible utility of the future, all new firm generating units must provide and contribute to system security and reliability by having technical and operational capabilities similar to existing thermal generation, allowing them to contribute to essential grid services. New variable generating units will also incorporate technical and operational characteristics to maintain system security and reliability. The Preferred Plan designated a mix of existing units, new firm capacity renewable generation, and additional variable generation renewable in conjunction with demand response and energy storage.

Our Preferred Plan includes the addition of 20 MW of new wind in 2020 and 25 MW of new geothermal on the west side of Hawai‘i Island in 2025. These resources are anticipated to provide our customers with lower cost renewable energy and higher RPS attainment. The plan will be updated as new information and/or resource options becomes available, such as waste-to-energy or ocean-based renewable generation.

Procurement of Replacement/New Generation

New generation resources will be procured through a competitive process. The Companies’ most immediate need for new, replacement generation is at Maui Electric, not Hawai‘i Electric Light. For example, the PSIPs for O‘ahu and Maui identify replacement generation being needed in 2022 and 2019, respectively. In addition, demand response programs and energy storage are planned to be implemented during in the immediate future that are expected to provide capacity reserves for both island power systems. The most urgent replacement generation is needed on Maui island, as it would provide for the timely retirement of the four generating units at Kahului Power Plant by 2019.

Below is a recommended process for competitively procuring the needed replacement generation for the Maui power system. A similar process is recommended for O‘ahu, and thereafter for Hawai‘i Electric Light as needed. Hawai‘i Electric Light has an RFP in progress for Geothermal Energy. Hawai‘i Electric Light has committed to modeling 25 and 50 MW of new IPP-owned geothermal projects and to issue a Request for Best and Final Offers for at least 25 MW. Per Commission order in Docket No. 2012-0092, the Request for Best and Final Offers shall be filed no later than September 25, 2014 for Commission review and approval.

Maui Electric – Maui Island

The PSIP for Maui island includes procurement of replacement/new firm generation resources in advance of the retirement of 36 MW and 4 MW of capacity at Kahului Power Plant and HC&S Power Purchase Agreement (PPA) termination, respectively, on or before 2019. The PSIP also indicates a need to locate a portion of the replacement/new generation in the South Maui Area in order to mitigate an under-voltage contingency without building new overhead transmission lines in the area. Subject to the Commission's concurrence, the following competitive process (not a waiver to the competitive bidding framework) will be implemented in the immediate future to procure the needed replacement/new generation.

1. Maui Electric will implement Demand Response programs in accordance with the *Integrated Demand Response Portfolio Plan* (IDRPP) to secure demand response (DR) capacity reserved on Maui island.
2. A technical specification will be prepared that describes the situation on Maui island, including the need for replacement generation for the retirement of KPP and termination of the PPA with HC&S. The specification will also describe the need for non-transmission alternatives (NTA) to new overhead transmission in the South Maui area, and how new generation and/or energy storage may be implemented to address the under-voltage contingency that exists.
3. The technical specification will describe the size, type, locations and timing of resources that may be proposed for implementation to meet the specified needs. Alternative resources and resource configurations that would meet the need would be invited to be proposed and will be given full consideration.
4. The technical specification would not provide target capacity for individual generating units or in total, but would likely specify minimum capacity size for individual units and capacities, and a maximum size for individual units (to meet system security and system operation and dispatch requirements).
5. At the Commission's direction, Maui Electric or an independent third party will run a competitive procurement process, including the issuance of a Request for Proposals (RFP) that utilizes the technical specification.
6. In parallel with Step 5, if requested by the Commission, Maui Electric would run a competitive process for the selecting and contracting of an Independent Observer (IO).
7. In parallel with Step 5, Maui Electric would run a competitive process for the selection and procurement of energy storage systems (based on the needs defined by the PSIP).

8. Maui Electric will prepare a "self-build option" for replacement/new generation in accordance with the technical specification described in Steps 2 and 3.
9. Maui Electric (or the third party designated by the Commission), in cooperation with the IO (if the Commission requested an IO) would evaluate the proposals received in response to the RFP issued in Step 5. The evaluation of proposals will be based, in parts, on the needs for the Maui island power system taking into account the results to procure energy storage and DR capacity reserves in Steps 7 and 8, respectively.
10. The results of the evaluation of the competitive proposals and the Maui Electric self build option would be submitted to Commission, with an accompanying recommendation by the IO (if the Commission requested an IO) on the selection of projects. The recommendation to the Commission would include a portfolio of energy storage, DR, and generation resources that meet the power system's needs as defined by Adequacy of Supply analyses and PSIP.
11. Pending approval by the Commission on the path forward, applications for approval of specific projects and/or power purchase agreements will be prepared and submitted to the Commission for approval. If approved, the projects and/or PPA would be implemented.

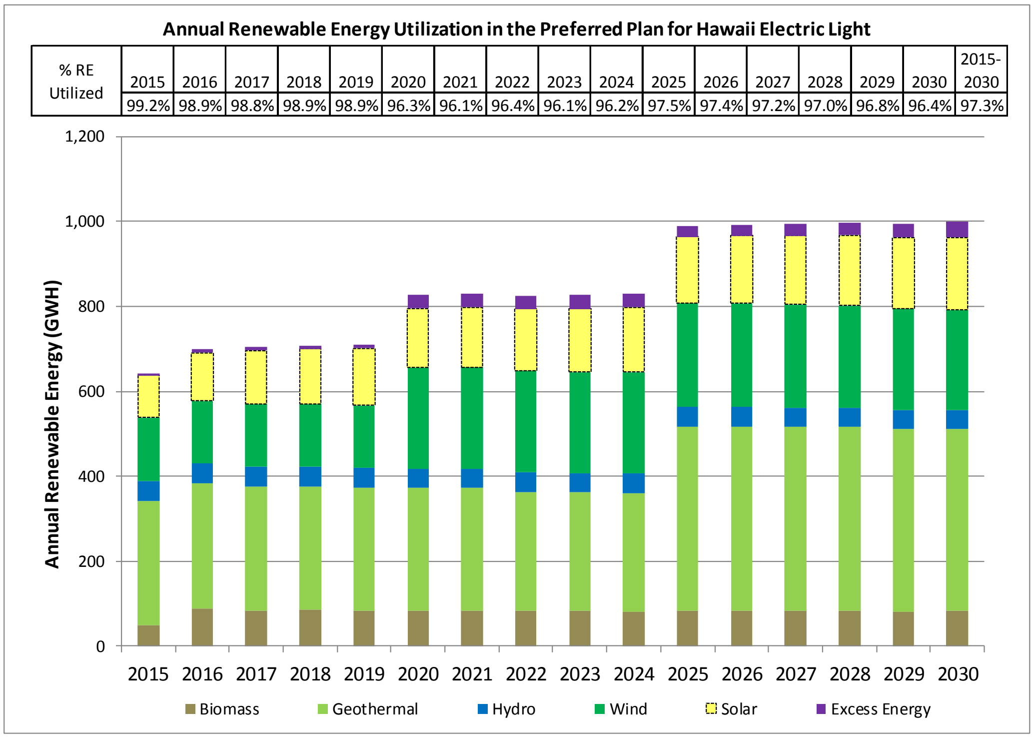
Utilization of Renewable Energy Resources

The Hawai'i Electric Light system has incorporated increased daily cycling and increased the dispatch range of existing thermal generation, which has greatly increased the amounts variable generation that can be utilized ("not curtailed") during low demand periods (which may occur during daytime hours, as well as night time, due to the influence of DG-PV). These factors, combined with incorporation of firm renewable energy, has created the highest use of renewable energy amongst the larger Hawai'i island grids. By acquiring additional new flexible firm renewable generation along with increasing wind generation, unprecedented high levels of variable renewable energy can be utilized. However, even with these improvements, non-firm renewable generation such as wind is occasionally available in quantities that cannot be effectively utilized by the system.

As shown graphically in Figure 5-7 below, exceptionally high levels of variable renewable energy can be utilized (that is, not curtailed) throughout the planning period. From 2015 through 2030, 96.4% to 99.2% of the estimated energy produced from all variable renewable resources would be utilized each year. The percentage of utilization drops slightly with the addition of non-firm utility-scale wind in 2020, then increases with the firm renewable geothermal addition in 2025.

It should also be noted that the utilization declines in the latter years of the planing period. The reason for the forecast demand reduction is that that energy efficiency is anticipated to grow exponentially during the end of the planning period. The projected demand reductions cause a slight decrease in utilization; however, the amount of energy curtailed remains extremely low, less than 4%, throughout the evaluation period.

Conversely, if there is slight load growth, for example due to higher adoption rates of electric vehicles, the execss energy condition would not exist and utilization of energy produced from variable renewable energy resources would approach 100%.



% RE Utilized	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2015-2030
	99.2%	98.9%	98.8%	98.9%	98.9%	96.3%	96.1%	96.4%	96.1%	96.2%	97.5%	97.4%	97.2%	97.0%	96.8%	96.4%	97.3%

Figure 5-7. Hawai'i Total System Renewable Energy

ENERGY STORAGE PLAN

Integrating energy storage is key to adding increased amounts of both distributed and utility-scale renewable generation into our power supply mix.

Energy storage provides unique operational and technical capabilities, including the ability to provide essential grid services. In addition, energy storage can be part of a portfolio of potential resources that can increase grid flexibility, operability, and reliability in a rapidly changing operating environment.

The Companies will evaluate and implement energy storage technologies and applications from two perspectives:

Utility Perspective: Evaluate energy storage in parallel with other resource options, such as new types of generation, modified operations of existing generating units, advanced planning and operational tools, smart grid and micro-grid technologies, and demand response programs.

Customer Perspective: Explore ways to utilize energy storage to provide a broader range of services for customers, including the utilization of energy storage within micro-grid environments, demand response, and thermal storage (for example, grid interactive water heating and ice storage). This perspective also includes the need to incorporate customer-owned energy storage as a grid resource, including possible ownership and operation of behind-the-meter energy storage assets.

The Strategic Energy Storage Plan (Energy Storage Plan) applies to all three operating Companies; however, due to differences in generation portfolios and operational needs, the action plans and timeframes for Hawaiian Electric, Hawai‘i Electric Light, and Maui Electric are expected to be different.

Appendix J – Energy Storage for Grid Applications, provides background information regarding the commercial status of energy storage, applications for energy storage, grid energy storage technologies, and the economics of energy storage, including capital and operating cost assumptions utilized in the PSIP.

Goals and Objectives of the Energy Storage Plan

The primary goal of the Companies’ Energy Storage Plan is to utilize energy storage in safe, cost-effective applications that enhance grid services to accomplish three outcomes:

- Optimize the costs of power system operation;
- Maintain acceptable reliability and security of the power system; and
- Expanded services to customers.

The following objectives will be pursued to achieve the Companies’ strategic vision:

- Pursue utility-owned and -operated energy storage projects under applications that make technical and financial sense, but at the same time, be open to non-utility storage options.
- Develop utility-owned and -operated distributed energy storage solutions and collaborate with industry and customers to utilize customer-sited storage as grid assets.

- Explore and pursue actions that address business model, utility cost recovery, customer rate schedules for different services, and regulatory issues that affect the Companies' ability to implement energy storage.
- Continue energy storage research and development activities.

Guiding Principles of the Energy Storage Plan

The following guiding principles will govern the implementation of the Companies' Energy Storage Plan.

Implement energy storage under a programmatic approach considering both utility-scale and customer-sited systems. Assess and implement an energy storage program for the deployment and operation of energy storage assets such that reliability, public policy, and customer interests are considered.

Both utility owned and independently owned storage will be considered.

Pursue energy storage to broaden the level of services for customers. The Companies will evaluate energy storage applications at the distribution level that increase customer value, including the contributions of customer-sited energy storage systems. The Companies are also open to owning energy storage systems on the customer-side of the meter to provide services to its customers. An example is the use of distributed, community-based and/or customer-sited storage to perform bulk load shifting. Another potential application of customer-sited energy storage is the use of EV batteries as energy storage for grid management purposes (Grid to Vehicle (G2V) and Vehicle to Grid (V2G) applications).

The timing of the Companies' plans to deploy energy storage and enter into contracts for services will consider technology maturity/development, pricing trends and development lead times. When determining the timing of energy storage system installation, the Companies must consider technology development and pricing trends and the estimated timelines required to design, permit, and construction such facilities. As discussed earlier, it is anticipated that some energy storage technologies will require considerable project development time.

Control of energy storage systems will be coordinated with other resources on the system through the Companies' Energy Management Systems (EMS). Any energy storage system providing system-level services, such as frequency regulation or response, must be coordinated with other resources on the grid; the system operator may accomplish this through the storage asset's local frequency response settings or through actual control of the energy storage asset. Although control will be centralized at the Companies' System Operation Control Center, distributed storage systems may be aggregated through a third party or through the Company's EMS or Advanced

Distribution Management System (ADMS). Also, since energy storage systems are finite energy resources, their operation must be transitioned to appropriate generation sources in a coordinated and controlled manner so that other resources can be made available when the storage is depleted. It is essential that any resource that is integral to system operations, including energy storage, be monitored at the system control center.

Energy storage will be considered in generation and transmission/distribution planning analyses to assess alternatives to generation and T&D projects. Planning for generation, transmission, and distribution assets and applications will include energy storage (and load management). A balanced portfolio of resources will be pursued during utility planning.

Collaborate with stakeholders and leverage external resources when available. The Companies will seek collaborative opportunities for energy storage solution development, especially on the customer side of the meter. External participation in energy storage solutions should be considered where it makes operational and financial sense. To offset technical and financial risks of unproven technologies or applications within a nascent energy storage industry, the Companies will seek opportunities for collaboration with external entities to leverage labor, expertise, and funding.

Energy Storage Operating Philosophy

The implementation plans for energy storage must be developed in concert with modified operating practices such as generation unit dispatch, load shed schemes, load management, and customer-focused solutions. By executing the energy storage strategy, the Companies will strive to:

- Ensure the Safety of the Company's crews and contractors working on either energized or non-energized distribution lines[34];
- Maintain or improve system reliability, and provide acceptable system reliability which is security through normal operation conditions and disturbances;
- Increase the value of electric services and lower cost to customers; and
- Develop a diverse portfolio of resources to reduce dependence on imported fossil fuels.

Energy Storage Operating Issues

Existing and growing levels of variable renewable energy resources, primarily wind farms and distributed PV, are creating the need for additional grid services. In the PSIP,

[34] The Companies will implement additional safety procedures to protect the safety of line crews, including design and installation of appropriate breakers and switching to ensure that energy storage will not inadvertently energize lines when our crews are performing repairs and maintenance.

Appendix E provides a description of essential grid services, and Chapter 4 provides a description of security analysis for increasing levels of distributed PV and new resources.

System impacts of the aggregate contribution of variable generation affect various time frames. These time frames determine the particular grid services that are required to mitigate these impacts.

Sub-Seconds to Seconds (primary frequency response time frame)

These impacts increase the need for frequency-responsive contingency reserves and regulating reserves:

- Fast ramping events (ramping of renewable resources exceeds ramping of dispatchable generation and primary frequency response for generation with governor response)
- Increased second-to-second frequency variation due to fast variability
- Increased rate-of-change of frequency during faults and contingencies
- Larger frequency impacts from faults and contingencies (lower frequency nadir result in increased under-frequency load-shedding)

Seconds to Minutes (supplemental frequency response and regulation time frame)

These impacts increase the need for regulating reserves and offline quick-start reserves (10-minute, 30-minute reserves):

- Increased need for second-to-second system balancing due to changes in variable generation output
- Sustained ramp events resulting in significant loss in wind or PV production to the system

Minutes to Hours

These impacts increase the need for offline reserves and require flexible options to balance supply and demand:

- Less predictability in the net demand to be served by generation
- Increased flexibility required from resources due to change in the nature of the demand served (that is, morning and evening peaks with low daytime and night time demand)

Energy Storage Uses in the Companies' Systems

Chapter 4 of the PSIP describes system security analysis that identified ancillary services for the existing and future possible system resource combinations. These services can be provided by storage. Detailed operational requirements are provided in PSIP Appendix E: Essential Grid Services. To adapt to the changing power grids, energy storage will be evaluated for its technical and cost effectiveness in providing the following applications/grid services:

Frequency Responsive Contingency Reserve

Application

- Respond very quickly to a change in frequency, to arrest frequency decay and mitigate under-frequency load shedding (UFLS).
- Provide sufficient energy capacity (MWh) during recovery period to provide time for operators to turn on units that cover generation deficit until combustion turbines (CT) can be started

Storage System Characteristics

- Fast response: Detect and respond within the first few cycles of sudden change in frequency
- High MW rating: Exact size is dependent on desired results
- Minimum MWh rating: Equal to MW rating times the amount of time needed to implement replacement reserves
- Must be constantly charged to a specific level of charge
- Must have the appropriate safety features to prevent energizing during periods when not required (that is, when workers are working on a de-energized portion of the line, or must be able to trip off due to a maintenance situation where a worker may be in the line)

Regulating Reserve

Application

- Dampen momentary frequency variations through governor-droop type response (if frequency responsive, this is required for a portion of the regulating reserve)
- Respond to AGC signals to increase or decrease output to regulate system frequency

Storage System Characteristics

- Governor-droop-like response to changes in system frequency (for frequency responsive regulating reserve)
- MW rating dependent on desired up/down regulation amount
- Control interface to AGC, responds within one AGC cycle
- Frequent charge/discharge cycle (may be every AGC cycle, 4–6 seconds)

- Must maintain energy for long enough for supplemental reserves to be brought online.
- Must have the appropriate safety features to prevent energizing during periods when not required (that is, when workers are working on a de-energized portion of the line, or must be able to trip off due to a maintenance situation where a worker may be in the line)
- Must have the appropriate safety features to prevent energizing during periods when not required (that is, when workers are working on a de-energized portion of the line, or must be able to trip off due to a maintenance situation where a worker may be in the line)

Load/Peak Shifting – System Ramping, Curtailment of Renewables, Economic Benefits

Application

- Absorb energy (charge) during periods of excess energy to minimize curtailment of variable renewables and optimize use of more efficient generation resources
- Provide power (discharge) during periods where there is demand for the energy

Storage System Characteristics

- MW rating dependent on desired deficit compensation
- High MWh rating (multiple hours) driven by amounts and duration of excess energy
- Must have the appropriate safety features to prevent energizing during periods when not required (that is, when workers are working on a de-energized portion of the line, or must be able to trip off due to a maintenance situation where a worker may be in the line)

Voltage Support – System Stability and Security

Application

- Provide dynamic VARs to regulate voltage (site specific)
- May be used to replace dynamic voltage support from generation resources, allowing them to be taken offline

Storage System Characteristics

- MVAR dependent on need
- Site-specific: MVAR support must be at location needed
- Fast-responding, dynamic, at a droop setting determined by specific requirement
- Discharge duration and minimum cycles per year not relevant for this use
- Must have the appropriate safety features to prevent energizing during periods when not required (that is, when workers are working on a de-energized portion of the line,

or must be able to trip off due to a maintenance situation where a worker may be in the line)

Black Start

Application

- Provide power that can be used for system restoration following system failure
- Used as an energy source to provide station power to bring power plants online and re-energize transmission and distribution lines following grid failure

Storage System Characteristics

- Able to self-start without grid power
- Able to be controlled remotely by the system operator
- MW rating able to provide startup energy to major generation resources, and absorb transformer inrush currents
- Must maintain enough charge after grid failure to provide system restoration services
- Must have capability to regulate voltage and frequency
- Must have the appropriate safety features to prevent energizing during periods when not required (that is, when workers are working on a de-energized portion of the line, or must be able to trip off due to a maintenance situation where a worker may be in the line)

Incorporating Energy Storage and Unit Commitment/Dispatch

Properly designed energy storage can provide the system operator with a flexible resource capable of providing capacity and ancillary services. In order to provide the system operator with appropriate control and visibility of energy storage, storage assets will be equipped with essentially the same telemetry and controls necessary to operate generating units. The specific interface requirements depend upon whether the storage device is responding automatically, or is under the control of the system operator. For devices that are integrated to the system control center, telemetry requirements include:

- Real-time telemetry indicating charging state, amount of energy being produced, and device status.
- Control interface to the operations control center to control the storage charging and discharging of energy.

Depending on the specific application, storage may also be required to respond to local signals. For example, storage may need the capability to respond to a system frequency change in a manner similar to generator governor droop response, which may be used for a contingency reserve response or for frequency responsive regulating reserve.

Another example of local response includes the ability of the storage to change output (or absorb energy) in response to another input signal from a variable renewable energy resource in order to provide "smoothing" of the renewable resource output.

A special consideration of short-duration storage is the fact that it is a limited energy resource. This introduces the need for the system operator to be informed regarding the storage asset's charging state, and the need to ensure that the integration and operation of these resources allows for replacement energy sources prior to depletion of the storage. This replacement could be in the form of longer-term storage or generation resources.

Incorporating energy storage into daily unit commitment and generator dispatch is dependent on how the storage is to be used.

Storage Used for Frequency Responsive Contingency Reserves: When used to provide frequency responsive contingency reserves, the storage asset must be operating on the power system as a security requirement. This storage stands ready to respond to short-term events and should not be deployed for regulation. The availability of storage for contingency reserves may reduce the number of online units required for system security and can be used to improve the response of the system to loss of generation events or similar disturbances that require an automatic response. It is important that the storage provides for sufficient energy duration so that replacement energy sources can come online before the storage is depleted.

Storage Used for Regulating Reserves: When used to provide regulating reserves, the energy storage will be committed and dispatched like any other resource used to provide regulating reserves via AGC commands. The storage would contribute to available reserves. In order to emulate the response of a generator, the storage will be equipped with frequency-response (droop) capabilities. The interface must provide enough information so the operator may bring online replacement reserves if the storage is depleted.

Storage Used to Provide Capacity: If the storage is used to provide capacity to serve load, then it will be treated like a generator and will be committed and dispatched in the same manner as a generator, based on marginal costs. However, because the energy storage resource will be limited in terms of how long it can provide capacity to the system, additional status monitoring capabilities will be required to ensure that the energy storage device is utilized in a manner consistent with its capabilities (for example, depth of discharge). This will also require that the daily unit commitment be performed to take into account the limits on duration of capacity available from the storage asset.

Customer-Side Energy Storage

The PSIPs did not specifically utilize customer-side energy storage devices. However, customer-side energy storage might be aggregated to achieve the same operational attributes as utility-scale energy storage. The aggregated storage concept allows storage assets to be properly sized and installed to meet bulk power supply needs and to help customers manage their electricity use. In order for distributed energy storage to be of value in bulk power applications, the following considerations must be taken into account.

Distributed energy storage can smooth the output of distributed solar PV. However, under the existing net energy metering rules, there is very little incentive for a customer to install their own energy storage device because customers essentially utilize the grid as a storage system. If the NEM arrangement is modified or eliminated and replaced with an arrangement that compensates customers based on a price that is more in line with the Company's marginal cost of generating energy for the system, then customers will have specific price signals that they can use to evaluate the benefits of installing their own storage.

Distributed energy storage may be useful through aggregation programs. Storage sited at customer facilities can not only play an active role in balancing load for the customer's site, but if aggregated, multiple customers' storage systems can provide a tool for providing grid services. Proper design of distributed storage programs will require additional investigation. However, the overhaul and expansion of time-based pricing programs that are part of the Companies' *Integrated Demand Response Portfolio Plan*[35] (IDRPP), and the concept of third-party aggregator programs provide opportunities to utilize aggregated energy storage for providing grid services.

Distributed energy storage will likely cost more than grid scale storage, however, it may be possible for distributed energy storage systems to be implemented faster than grid-scale systems. Due to economies of scale inherent in utility-scale storage applications, customer-side energy storage is expected to have a higher capital cost on a per unit of storage capacity installed. Even as battery costs decline, this cost disadvantage relative to grid scale storage will remain since the balance of plant components is expected to be higher per unit of capacity for distributed storage. While it is assumed that any customer-side energy storage project would be paid for by the customer, the compensation that can be paid by the Companies to customers for customer-side energy storage must reflect the cost of alternatives available to the Companies; otherwise excess costs will be borne by ratepayers. The value proposition for the customer is being evaluated through an active initiative with storage technology providers.

[35] See *Integrated Demand Response Portfolio Plan*. Hawaiian Electric Companies. Docket No.2007-0134. July 28, 2014.

In order to provide certain grid services, distributed energy storage must be equipped with proper telemetry / communications to allow coordination with grid operations; the telemetry / communications design must provide for operation within specified performance time frames. Advances in communications utilizing Internet protocols (IP) and cloud-based aggregation technologies are now more prevalent in the industry. With the addition at the distributed storage site of control hardware with communication backhaul to an aggregator/coordination point for the utility, near real-time storage asset status and the ability to control the storage asset can be provided for customer-sited storage. For essential grid services response, an aggregated response would be needed to manage local distribution conditions as well as provide some of the support services to manage ramping of locally sited distributed PV. The response time is a function of both communications latency and the ability of a distributed resource itself to respond in the time frames required by certain grid services. These response times are described in Appendix E, Essential Grid Services. For example, regulating reserves must beimmediately responsive to AGC (observable change within 2 seconds) signals, which requires an interface to the Energy Management System (EMS). Distributed energy storage used to provide grid services with fast response requirements and integration with the EMS must also be equipped with the proper telemetry and communications infrastructure. Depending on the business model, the cost of the communications infrastructure is in addition to the cost of the storage product. This cost may be incurred by the customer, or by aggregators who manage the telemetry devices. The cost/benefit must consider the interface costs and value benefit for the customer and utility. Without coordination and visibility by the utility, the value of customer-sited storage is diminished.

The Companies are engaged in conversations with customer storage integrators and suppliers to develop and test advanced integration and management features for customer-sited energy storage systems.

Energy Storage in the Preferred Plan

The Preferred Plans for the three operating companies include specific energy storage additions summarized below. These are additions on top of energy storage already installed in the respective systems, and could change as the Companies conduct further technical and economic analyses. Table 5-4 through Table 5-6 show the energy storage additions that are in the Preferred Plan (demonstration projects are not shown).

Year Installed	Capacity	Type of Storage Device	Storage Duration	Purpose
2017	200 MW	Battery (advanced lead-acid or lithium ion) or Flywheel	20 min	Contingency reserves to bring O'ahu system into compliance with security criteria
2022	100 MW	Battery (advanced lead-acid or lithium ion) or Flywheel	30 min	Regulation

Table 5-4. Hawaiian Electric Preferred Plan Energy Storage Additions

Year Installed	Capacity	Type of Storage Device	Storage Duration	Purpose
2015 (Maui)	2 MW (committed project)	Battery	11 min	Frequency regulation; PV DG-PV support
2018 (Lana'i)	10 MW	Battery	90 min	Contingency reserves; DG-PV support
2018 (Moloka'i)	10 MW	Battery	90 min	Contingency reserves;
2019 (Maui)	20 MW	Battery	30 min	Regulating reserves; reduce regulating reserves carried by thermal units
2019 (Maui)	20 MW	Battery	30 min	Contingency reserves. Bridge until quick start RICE units can be installed for voltage support in South Maui

Table 5-5. Maui Electric Preferred Plan Energy Storage Additions

Year Installed	Capacity	Type of Storage Device	Storage Duration	Purpose
2017	5 MW	Battery (advanced lead-acid or lithium ion)	30 min	Managing variable generation ramping events
2017	20 MW	Battery (advanced lead-acid or lithium ion)	20 min	Contingency reserves

Table 5-6. Hawai'i Electric Light Preferred Plan Energy Storage Additions

Hawaiian Electric Energy Storage RFP (O'ahu)

On April 30, 2014, Hawaiian Electric issued an RFP for energy storage. The RFP requested proposals that encompass engineering, procurement, construction, testing, commissioning, start-up, and performance verification from 60 MW up to 200 MW for a storage duration of 30 minutes to the grid (the Project). (The Project could consist of multiple energy storage systems installed at multiple locations on the grid.) As previously discussed herein, storage durations up to 30 minutes are useful for the provision of ancillary services, and the capital cost of storage may be more attractive than building a new generator, provided that the storage system can respond within the time frames required for ancillary services.

Interested bidders were requested to submit proposals describing sizing, storage technologies, and operational capabilities of their energy storage system. Bidders were encouraged to propose projects on a number and size that optimizes their technology for Hawaiian Electric's system needs.

The overall objectives of the Project are to incorporate into the energy storage system as many of the functions below as practical and cost effective:

- Provide an additional resource to help manage system frequency by absorbing or discharging energy on a minute-to-minute basis to help maintain system frequency at 60 Hz.
- Provide energy for a short duration during the recovery period after a sudden loss of generation until a quick starting generator can be brought online.
- Provide an immediate injection of a large amount of energy for a short duration in the event of a sudden loss of generation to decrease the need to utilize load-shedding blocks.
- Assist Hawaiian Electric's generation fleet with meeting system load variations due to intermittency of renewable generation caused by unpredictable wind or sun availability.
- Provide Hawaiian Electric with grid operational flexibility to reasonably manage distributed, intermittent generation with the island electrical load.

Bidders were encouraged to propose the best technology solution to meet the Companies' technical and operating needs. The RFP explicitly asked for proposals that might utilize any of the following technologies:

- Battery energy storage
- Mechanical flywheel energy storage
- Capacitor energy storage
- Compressed gas (for example, air) energy storage
- Pumped storage hydroelectric
- Any combination of the above

Proposals were received on July 21, 2014. The proposals are currently under review and in order to protect the integrity of the RFP process cannot be discussed here in detail. However, generally the proposals received included lead-acid batteries, several forms of lithium-ion batteries, flow batteries, pumped-storage hydroelectric, and mechanical flywheels. Pricing proposals are generally consistent with the PSIP assumptions detailed above.

Hawaiian Electric intends to evaluate these proposals, and if cost and technical requirements are met, make an award on or about August 29, 2014.

Utilization of Energy Storage on O'ahu

Companies already have energy storage technologies and application evaluation programs in place. These include the following field demonstration projects:

- Hawaiian Electric is collaborating with Hawai'i Natural Energy Institute (HNEI) of the University of Hawai'i to test the ability of a one MW/250 kWh fast-response lithium-titanate battery (purchased by the University of Hawai'i with a federal grant) to help smooth power fluctuations and regulate voltage on a feeder with high distributed PV penetration on O'ahu. The battery energy storage system (BESS) will be operated to evaluate circuit-level functions, such as power smoothing and voltage regulation, and system-level frequency response to assess whether this technology is feasible and to provide Hawaiian Electric with operational experience with distributed energy storage technology. Installation is targeted for late 2014.
- Hawaiian Electric is collaborating with STEM to deploy and demonstrate the aggregated dispatch and response capabilities of distributed energy storage systems in commercial and industrial load management applications. These storage assets will be coordinated with utility operations to help manage high penetration PV conditions. This program will provide valuable information regarding the installation and use of new telemetry devices, and will provide operational and customer experience with aggregated storage resources. The lessons learned from this program will be used to help design effective aggregator programs. This effort leverages the funding provided to STEM by the State's Energy Excelerator Program. Installation is targeted for late 2014 through early 2015.

The Companies will continue their energy storage demonstration projects of substation-sited and other distributed applications to build its experience base of technical and cost characteristics. These efforts will continue in parallel to commercial applications that are implemented to meet critical operational needs.

Utilization of Energy Storage on Maui and Lana'i

To varying degrees, existing battery energy storage systems on Maui and Lana'i have the potential to be repurposed to better serve the needs of the entire electrical system. In fact, one of the third-party owned existing batteries on Maui is already used to provide frequency regulation. Given their size in relation to their respective grids, it may be possible to utilize the other battery energy storage system on Maui, and the third-party owned battery energy storage system on Lanaʻi, for frequency regulation as well. However, in cases where the battery energy storage system is not owned by Maui Electric, the ability to repurpose the energy storage system will be contingent on negotiations of contract terms between the utility and each owner. Amendments to current contract terms would be as agreed upon by the parties and approved by the Commission.

Existing Storage at Maui Electric

The Maui system currently contains two battery energy storage systems that are owned and operated by third parties. The Kaheawa Wind Power II, LLC (KWP2) facility couples a 21 MW wind farm with a 10 MW/20 MWh battery energy storage system. The KWP2 battery provides system support in the form of frequency regulation and regulating reserve. In addition, the KWP2 BESS provides ramp rate control of its wind power output to meet ramp rate limits required by the Power Purchase Agreement (PPA).

The Auwahi Wind Energy, LLC (AWE) facility couples a 21 MW wind farm with an 11 MW/4.4 MWh battery energy storage system; the AWE battery was installed to allow the facility to meet the performance standards of their PPA, primarily ramp rate control.

In addition, Maui Electric owns and operates a 1 MW/1 MWh battery energy storage system located at the Wailea substation as part of the Department of Energy (DOE)-funded, HNEI-led Maui Smart Grid project. The Maui Smart Grid project battery provides peak circuit load reduction and voltage support. Operation of this battery is expected to continue through 2018. Several other smaller batteries are located across Maui as part of different research efforts, including the JUMPSmart project.

Several smaller batteries are targeted for installation on Maui as part of the Japan U.S. Maui Smart Grid Project (JUMPSmart). This project, in collaboration with Maui Electric, Hitachi, Hitachi Advanced Clean Energy Corporation, and the New Energy and Industrial Technology Development Organization in Japan (NEDO), will evaluate the aggregation and management of distributed energy storage and other distributed resources through smart grid technology.

Existing Energy Storage on Lanaʻi

On Lanaʻi, the Lanaʻi Sustainability Research, LLC (LSR) 1.2 MW photovoltaic facility incorporates a 1.125MW/500 kWh battery energy storage system within their generation facility design. Similar to the AWE battery, the LSR battery is utilized to allow the facility to meet the performance standards in their PPA, primarily ramp rate control.

Planned Energy Storage on Moloka‘i

Maui Electric, in collaboration with HNEI, is currently pursuing a 2MW/375 kWh battery energy storage project on the island of Moloka‘i to provide frequency regulation and PV integration support. Technical assessments on the optimal use of the battery are currently underway. Although a project schedule has not yet been developed, installation of the BESS is anticipated to occur in 2015.

Utilization of Energy Storage on Hawai`i

Hawai‘i Electric Light on Hawai‘i Island is collaborating with HNEI to test the ability of a one MW/250 kWh fast-response lithium-titanate battery to smooth the output of the Hawi Renewable Development wind farm. The battery was purchased by HNEI with a federal grant. The BESS was commissioned in December 2012, and continues to be operated for evaluation.

Hawai‘i Electric Light has installed 100 kW/248 kWh lithium ion batteries at two customer-owned PV projects on Hawai‘i Island using USDOE stimulus funds awarded through the State of Hawai‘i Department of Business, Economic Development and Tourism (DBEDT). These BESS projects, installed in July 2012, are helping Hawai‘i Electric Light Company evaluate the battery’s ability to smooth fluctuations of commercial-scale PV projects.

TRANSMISSION AND DISTRIBUTION SYSTEM DESIGN

Transmission

The role of the transmission systems for the Hawaiian Electric Companies remains the same – that is to transmit bulk power from one point to another in a networked configuration at current transmission voltages.

While the role of the transmission system on O‘ahu remains the same, changes in its design have been identified as part of the PSIP. Specifically, the Hawaiian Electric PSIP identifies the expansion of the O‘ahu 138kV transmission system through a transmission loop from the central area to the northern area of the island. Currently, O‘ahu’s 138kV transmission system is limited to the leeward, central and southern portions of the island. Yet, there has been much interest and demand for interconnection of utility-scale and distributed renewables from the northern and central areas of the island. A new transmission loop can interconnect renewable generation from this part of the island beyond the capacity of existing subtransmission circuits in the area in-line with the Preferred Resource Plan for O‘ahu.

Similarly, the role of the transmission system on Maui remains the same. However, the PSIP identifies the addition of a new 69 kV transmission line between substations in Wailuku and Kahului in order to provide greater voltage regulation of the 23 kV system in Central Maui, defer overloads of 69-23 kV transformers, and allow for the retirement of all generators of Kahului Power Plant as identified in the Maui Electric PSIP for 2019.

On the island of Hawai‘i, the role and the design of the transmission system remains the same. However, if additional generation is built on the East side of the island beyond what is included in the Hawai‘i Electric Light PSIP (such as an additional increase in geothermal generation), the design of Hawai‘i Island’s transmission system would require additional transmission capacity to reliably transmit bulk generation from the east side to the west side of the island.

Distribution

In contrast to the transmission system, the role of the distribution systems does change dramatically as part of each Company’s preferred resource plans. The previous role of distribution system was to serve local power loads only. As part of the PSIP and DGIP, the distribution system will continue in its role to serve in the role of serving local loads, but now will also have an additional role of collecting and reliably delivering DG power and energy up to the sub-transmission or transmission systems. This is necessary in order to accommodate approximately 600 MW, 120 MW, and 120 MW of DG-PV on O‘ahu, Maui, and Hawa‘i islands, respectively.

As detailed in the Companies’ DGIP report, the Hawaiian Electric Companies plan to continue to use a radial architecture for the distribution system as a more cost-effective alternative compared with building a new networked distribution system. But in order to fulfill its new role to collect and reliably deliver DG power up with a radial architecture, the design of the distribution will need to be modified by: 1) upgrading circuit components such as replacing LTCs with newer designs capable of regulating voltage in two directions; 2) adding new circuit components, such as the addition of grounding transformers to address ground fault over-voltage events, to ensure operating conditions on all circuits remain within expected and allowable limits; and 3) adding intelligence and controls throughout the distribution circuit and substation along with two-way communications to monitor and control inverter operation, switching, regulation of voltages and management of power flows on distribution feeders.

It should be noted that as part of design of the transmission and distribution (T&D) system over the planning period, the utility’s telecommunications system will play an increasingly important role in the operation of the T&D system. In fact, one should think of the transmission and distribution system evolving into a transmission, distribution, and communications system design. This communications system is not only an essential part of the Company's Smart Grid Program, it is an essential part of the Companies' plan to modify and upgrade its distribution system to allow for the integration of greater levels of DG, as well as to allow for the interoperations between utility's grid systems with customer-side equipment such as advanced inverters, storage devices, and control systems.

Such design changes for the distribution system are common to all Hawaiian Electric Companies and they are discussed in detailed in our DGIP.

In order for the transmission and distribution system to reliably operate in its various roles through the planning period of the PSIPs, the Hawaiian Electric Companies must intelligently integrate its Smart Grid and DGIP upgrades with its Asset Management programs. All components of a circuit (such as conductors, wires, breakers, switchgear, transformers, poles, and others) must be replaced on a programmatic basis in an asset management program to ensure that the transmission and distribution system remains reliable and able to serve in its increasingly important role in the grid. However, such replacement and upgrades much be done not just for age or condition reasons, but to also be done to add the control and communications functionality described in the Smart Grid plan and DGIP. By integrating plans for Smart Grid and DGIP with the Asset Management program, savings and efficiencies can be achieved as grid components are replaced and upgraded.

ENVIRONMENTAL COMPLIANCE

The Hawaiian Electric Companies must comply with environmental laws and regulations that govern how existing facilities are operated, new facilities are constructed and operated, and hazardous waste and toxic substances are cleaned up and disposed.

Complying with air and water pollution regulations could require the Companies to commit significant capital and annual expenditures. Chapter 9 of the 2013 IRP Report[36] described the environmental requirements of the Companies. This section describes any updates to the filing and provides additional environmental requirements that were not discussed.

Hawai'i Electric Light Environmental Compliance

Hawai'i Electric Light analyzed alternatives for environmental compliance in the 2013 IRP. Obtaining compliance through fuel switching was the most economical alternative.

[36] Docket No. 2012-0036, Integrated Resource Planning for the Hawaiian Electric Companies, filed June 28, 2013.

National Ambient Air Quality Standards (NAAQS)

As shown in the 2013 IRP, compliance with NAAQS through the use of diesel fuel switching strategy was the lowest cost option.

Greenhouse Gas (GHG) Regulations

In 2012, the DOH issued a proposed state GHG rule to achieve the goals of State of Hawai‘i Act 234, the Global Warming Solutions Act of 2007 (Act 234) which mandates that statewide GHG emissions be reduced to 1990 levels by 2020. DOH addressed public comments to the proposed rule in 2013. The GHG regulations were recently signed by Governor Abercrombie and became effective on June 30, 2014.

The regulations issued by the DOH requires entities that have the potential to emit GHGs of more than 100,000 tons per year of carbon dioxide equivalent (CO2e) to reduce GHG emissions by 16 percent below 2010 emission levels by January 1, 2020, and maintain those levels thereafter. Ten power plants operated by the Hawaiian Electric Companies meet the applicability condition. Hawaiian Electric has one year to submit GHG emission reduction plans to DOH for its affected power plants. These plans will explain how each facility intends to meet its GHG reduction threshold by the 2020 target date, what technology will be employed, and how the reduction will be sustained going forward. For greater flexibility, the proposed rule allows affected facilities to “partner” among each other to meet GHG reduction targets. That is, one affected facility can agree to “transfer” some of their allowable GHG emissions to another facility to meet the reduction target for the second facility in cases where that facility might not be able to meet their target on their own.

On June 18, 2014, EPA published a proposed rule that would establish GHG performance standards for existing power plants under Clean Air Act Section 111(d)[37].

The Clean Air Act requires EPA to establish a “procedure” for each state to follow in implementing Section 111(d) that is “similar” to the state implementation plan procedures laid out in Section 110 of the Act. Section 111(d) delegates to the states primary responsibility for both developing and implementing the performance standards.

EPA is proposing state-specific GHG emission reduction targets and a two part-structure for states to achieve the targets. States would be required to meet an “interim goal” on average over the ten year period from 2020–2029 and a “final goal” in 2030 and thereafter. EPA also identifies a number of potential options for states to meet the proposed targets. Using EPA’s 2012 baseline, Hawai‘i would have to reduce its statewide CO2 emission rate by approximately 15% to meet EPA’s proposed 2030 final goal.

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[37] 79 Fed. Reg. 34830

EPA developed the proposal pursuant to a 2013 directive from President Obama. The directive requires EPA to finalize the proposal no later than June 1, 2015, which will start the one-year period for states to complete and submit state plans to EPA. Hawaiian Electric is studying EPA's proposal and will actively participate in the rulemaking.

The Hawaiian Electric Companies are committed to taking direct action to mitigate the contributions to global warming from electricity production. Such action has, and will, continue to include promoting aggressive energy conservation and transitioning to clean, efficient and eco-effective energy production in all markets that the Company serves. Hawai'i Electric Light is already taking active steps to mitigate contributions to global warming by investing in and committing to integrate renewable generation, and energy conservation.

SYSTEM RELIABILITY AND STABILITY

For each year of the study period, Hawai'i Electric Light's Preferred Plan incorporates the system reliability criteria further described in Chapter 4. The production simulation models include system reliability criteria such as increasing the required regulating reserves each year to mitigate additional variable renewable wind and solar generation. The regulating and ramping reserves needed for system reliability are met by combinations of thermal and renewable dispatchable units and energy storage additions on the system.

Ancillary Services

Currently, Hawai'i Electric Light uses its existing and IPP resources to operate its system today as economically as feasible while maintaining acceptable reliability. Utility-scale variable renewable resources and distributed generation resources create uncertainty in actual system operations which require a combination of operational flexibility, system modifications, and technology improvements to preserve system security.

Ancillary Services from Renewable Generation

In addition to supplying energy, generators provide capabilities critical for system security. The technical and operational characteristics determine if, and to what extent, these resources can contribute to essential grid services (Ancillary Services), as described in Appendix E. These capabilities are not consistent or equivalent for all generators as shown in Figure 5-8 below.

Generation Resource	Inertial/ Frequency Response	Ramping For Load Following/ Frequency Regulation	Fast Startup	Voltage Reg	East West Power Flow Balancing	Black Start
A=Excellent	B=Good	C=Some Ability	Negative Impact	Blank=neutral		
Hu Honua	A	B		B		
Hill 5	A	B		B		
Hill 6	A	B		B		
Puna	B	B		B		
CT1	B	A	A	B		A
CT2	B	B	A	A	A	A
CT3	B	A	B	A		A
Kea CC	A	A		A	A	C
Diesels	C	C	A	A	B (Keahole)	
HEP CC	A	A		A		B
PGV	B	C		A		
Hydro						
Wind				A		
Distr PV						

Blank indicates the resource does not contribute to the listed function.

Figure 5-8. Simplified Portrayals of Existing Generating Unit Capabilities.

In order to support system security, generating units must have operational and technical characteristics to support the system security constraints: frequency response, inertial response, dispatch control under AGC for ramping, frequency regulation, and load following.

Load Shed, the Rate of Change of Frequency, Ramping Capability, and Regulation are all related to system frequency response and system balancing needs. Frequency control is a significant challenge due to Hawai‘i Electric Light’s small system size and its isolation. With no interconnections to any other electrical grid, any imbalance between energy production and demand results in frequency error. A relatively small imbalance will result in a large frequency change.

If operating with the minimum online generation, multiple contingencies (such as what may occur during lightning storms or earthquakes) will be more likely to lead to system failure (that is, an island-wide blackout).

Ancillary Services from Demand Response

Hawai‘i Electric Light discussed ancillary services in our Power Supply Plan filed in Docket No. 2012-0212 on April 21, 2014. Refer to Attachment 8A – Potential for Beneficial Demand Response on the Hawai‘i Electric Light System - An Operational Perspective.

Ancillary Services from Energy Storage

Energy storage opportunities on the Hawai‘i Electric Light system were evaluated in our Power Supply Plan in Exhibit 9 – Energy Storage Opportunities at Hawai‘i Electric Light.

6. Financial Impacts

The PSIP presents a Preferred Plan for the transformation of Hawai‘i Island’s power system. The analyses used in the development of the Preferred Plan were based on numerous assumptions (discussed in Chapter 4 and quantified in Appendix F).[38] The transformation of the power system will require significant investments by both the company and third parties to build the necessary flexible, smart, and renewable energy infrastructure needed to reliably serve customers across Hawai‘i Island. The PSIP requires a reliable, well-maintained transmission and distribution (T&D) system, a thermal generation fleet to firm variable renewables, and related infrastructure to achieve this transformation.

A strong and resilient grid is foundational for meeting our customers’ needs for safe and reliable electric service, serving new customers and new electric loads such as electrified transportation, and providing energy services more generally. Investments to maintain, and as necessary expand, this foundational infrastructure are termed “foundational investments”. These foundational investments are essential and complementary to the transformational investments defined by the PSIP. The investment requirements of the PSIP, including both transformational and foundational investments, are presented in detail in Appendix K. The magnitude and impacts of these investments are analyzed and discussed in this chapter in terms of customer affordability as measured by full service residential customer bill impact in real dollars (that is, 2014 dollars).

By combining the transformational together with the foundational investments, including their impact on fuel and O&M expenses we provide a comprehensive analysis of customer affordability. Implicit in these financial analyses is the Company’s ability to maintain affordable and ready access to capital markets.

[38] We acknowledge that actual circumstances may vary from what was assumed in the analyses, and accordingly, the PSIP will need to be revised and/or actions will need to be reviewed and updated from time to time.

RESIDENTIAL CUSTOMER BILL IMPACTS

The rate reform proposed in the DGIP[39] provides a rate design that reduces average monthly bills in real terms for average[40] residential full service[41] customers to approximately 30% below 2014 levels by 2030 while more fairly allocating fixed grid costs across all customers. The residential customer bill impact with DG-PV reform is discussed in detail in the next section of this chapter. The discussion immediately below presents the customer bill impact under current rate design to facilitate the comparison with the customer impact under the proposed DG-PV reform.

As show in Figure 6-1, in the early years, the bill impact of capital investments made to transform the system is mitigated by the conversion of several assets to lower cost containerized liquefied natural gas (LNG) in 2017.

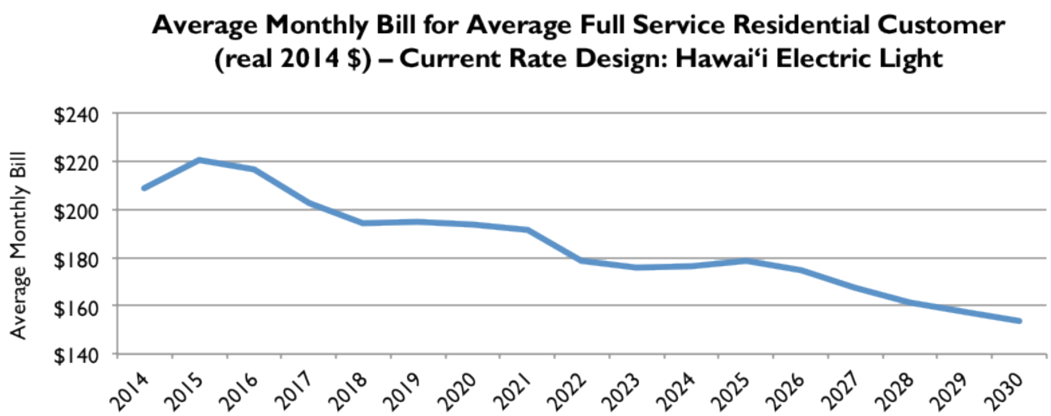

Figure 6-1. Monthly Bill for Average Full Service Residential Customer under Current Rate Design

These bill impact analyses assume that the residential customer class continues to be responsible for its current percentage of the total revenue requirement. This is a reasonable simplifying assumption, given that this class responsibility has been largely unchanged over the last 20 years or more.

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[39] The Companies filed their *Distributed Generation Interconnection Plan* (DGIP) on August 26, 2014.

[40] Average is defined by taking the total usage across all full service customers and dividing by the number of full service customers in a given year. The average bill is not meant to project an actual future customer bill, but is illustrative of the bill impacts anticipated for customers with an average amount of usage across full service residential customers.

[41] Full Service Customer is defined as any residential or commercial customer that imports the entirety of their energy demands from the grid, and does not self-consume or export any energy derived from distributed energy resources co-located with their load.

RESIDENTIAL CUSTOMER BILL IMPACTS WITH DG-PV REFORM

In this section, we estimate the average monthly bill for average, full service and DG residential customers assuming specific adjustments to rate design for all residential customers, including those with DG-PV. It is important to note that this is one potential approach to rate design among many other possibilities. Use of this approach for customer bill projections is not meant to advocate for or against this rate design versus any other, but instead is meant to demonstrate the relative impact to residential customer bills as a result of one possible set of rate design changes intended to address various challenges and concerns as discussed in the DGIP filing.[42]

The financial analysis utilizing this rate construct illustrates how such an alternative approach to DG-PV could result in average monthly bills for average full service residential customers that are, in real terms, 30% lower in 2030 as compared to 2014 (that is, an additional 3% lower than under the current rate design) and more fairly allocates fixed grid costs across all customers.

Outline of Hypothetical DG-PV Reform (DG 2.0)

The Company's strategic vision for DG-PV encompasses reform of the rates governing DG-PV interconnections under an overall approach to distributed generation called "DG 2.0". As part of DG 2.0, the current net energy metering (NEM) would be replaced with a tariff structure for DG systems that more fairly allocates fixed grid costs to DG customers and compensates customers for the value of their excess energy. For modeling purposes, DG 2.0 is assumed to begin for all new DG customers in 2017; customers who interconnect before 2017 will retain the tariff structures under which they applied.

As a party to Order No. 32269 issued by the Commission on August 21, 2014, the Companies view this as an opportunity to evaluate the precise nature and timing of the DG 2.0 rate reform. A preliminary set of assumptions regarding DG 2.0 has been made to facilitate the financial and capacity modeling performed in this PSIP and the DGIP, but these assumptions should not be interpreted as a policy recommendation.

These rate assumptions adhere to the underlying principles of the Company's DG strategy and include the following:

- A fixed monthly charge applied to all customers, allocating fixed customer service and demand costs in a fair, equitable and revenue-neutral manner within customer classes.

[42] Additional policy options are described further in the DGIP.

- An additional fixed monthly charge applied only to new DG customers to account for additional standby generation and capacity requirements provided by the utility.
- A "Gross Export Purchase model" for export DG. Under this model, coincident self-generation from DG-PV and usage is not metered and customers sell excess electricity near wholesale rates and buy additional electricity at variable retail rates.

For the purposes of these projections, fixed monthly charges are assumed to comprise demand and customer service charge components.

The fixed demand charge has been estimated in two steps. First, a capacity requirement across all customers that would minimize cost shifts to low-usage customers was determined. Second, the fixed cost of meeting this capacity requirement for production, transmission, and distribution was calculated. An additional demand charge was also applied to DG 2.0 customers due to the higher peak capacity requirements that DG customers have, on average, compared to the broad class of residential customers.

In addition to fixed capacity-based charges, monthly customer charges were estimated by allocating the fixed costs associated with servicing individual customers across all relevant households. These costs were assumed to be uniform within customer classes.

These fixed charge projections, along with assumed feed-in tariff (FIT)rates under the envisioned Gross Export Purchase model are shown in Table 6-1.

Residential Customer Groups	Monthly Fixed Charge – All Residential Customers	Monthly Fixed Charge – DG Only	Feed-in Tariff Purchase Price	Tariff for Energy Consumed from Grid
Current NEM Customers	$61	n/a	n/a	n/a, within NEM energy balance, retail rate for any shortfall
DG 2.0 Customers	$61	$16	$0.18	Retail rate
Full Service Customers	$61	n/a	n/a	Retail rate

Table 6-1. Estimated Hawai'i Island DG 2.0 Customer Charges and Feed-in Tariff Rate

OVERVIEW OF DG-PV FORECASTING

As customers respond to a revised set of market incentives such as DG 2.0, the rate of DG-PV installations will change. A market-driven forecast for DG-PV demand, assuming DG 2.0 is implemented in 2017, has been developed. At a high level, these forecasts estimate what DG-PV uptake will be as regulatory reform transitions away from existing

DG programs (including NEM) over the next two years and implements DG 2.0 in the medium term. Accordingly, this PSIP has used DG-PV forecasts that were based on two distinct phases of DG uptake.

From 2014 to 2016, a set rate of interconnection under existing DG programs was assumed, based on simplifying assumptions about queue release and the pace of new applications.

From 2017 onward, the DG 2.0 tariff structure is assumed to apply across all customer classes.[43] Using benchmarked relationships between the payback period of PV systems and customer uptake rates, we projected market demand for new PV systems among all residential and commercial customer classes.

Based on this methodology, the projected number of residential customers on Hawai'i Island with DG-PV would grow by about 225% from approximately 5,500 at the end of 2013 to approximately 18,000 in 2030. While this forecast will undoubtedly shift as more detailed policies are developed, it has been used as an essential input for all of the PSIP analyses.

Residential Customer Bill Impacts Under DG 2.0

The reform of DG-related rates has a material impact on average monthly bills for full service residential customers. As shown in Figure 6-2, the projected average monthly bill for an average full service residential customer drops by 30% in real terms over the 2014 to 2030 period.

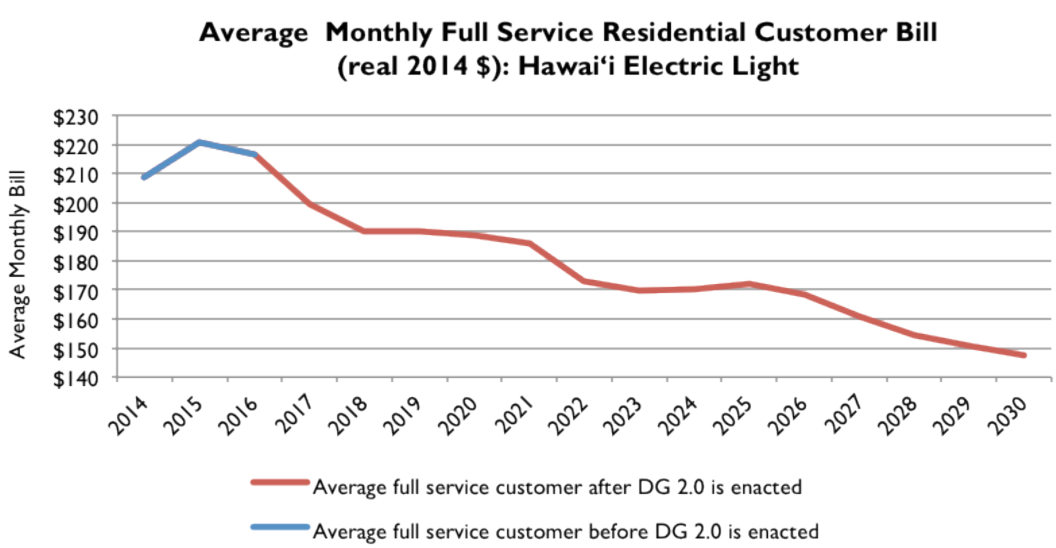

Figure 6-2. Average Full Service Residential Customer Bill Impact under DG 2.0

[43] With the exception of grandfathered current NEM customers.

As discussed above, DG 2.0 is assumed to take effect in 2017. This results in a bill reduction for full service residential customers in 2017 that grows throughout the planning period, as compared to the current rate design.

Under the DG 2.0 concept, current NEM customers would see an increased average monthly bill due to the increased fixed monthly demand and customer charges for all customers beginning in 2017, partially offset by the decrease in variable retail rates charged to all residential customers for electricity taken from the grid. The bill impact for new residential DG customers would include those charges, as well as the fixed charge for higher capacity and their net cost from the "Gross Export Purchase" model. Average full service customer average monthly bills would decrease under DG 2.0, despite the increase in fixed monthly demand and customers charges, as a result of the decrease in variable retail rates. Bill impacts for these customer groups, both under the current tariff structure as well as DG 2.0, are shown in Figure 6-3.

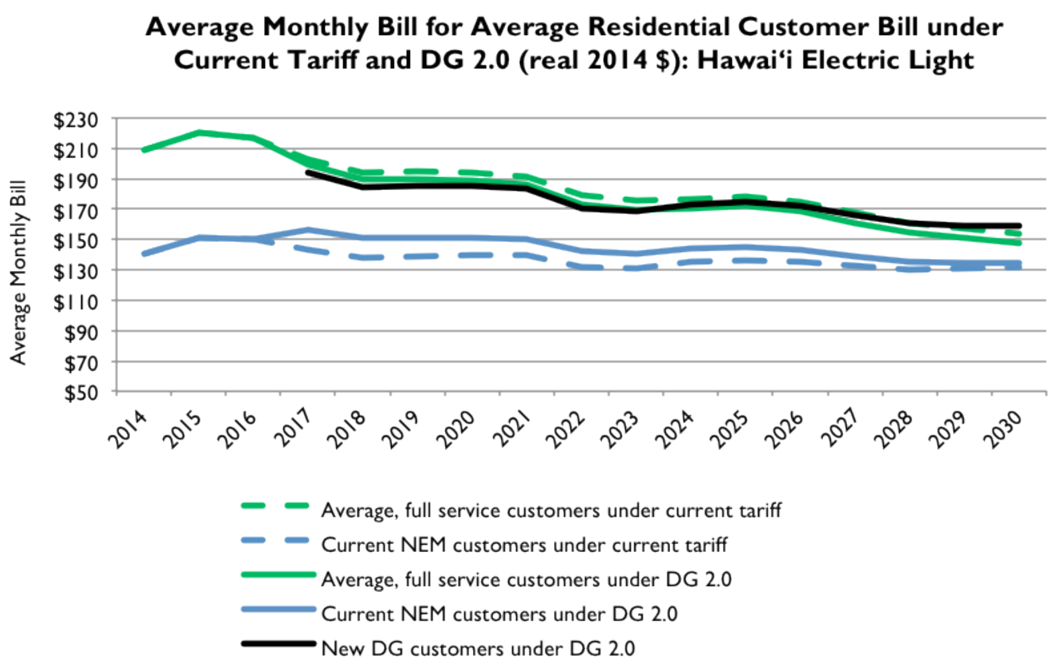

Figure 6-3. Average Residential Customer Bill Impact under Current Tariff and DG 2.0

POTENTIAL POLICY TOOLS TO FURTHER SHAPE CUSTOMER BILL IMPACTS

This PSIP, coupled with the DGIP and the IDRPP, demonstrate a comprehensive path forward to achieve higher levels of renewable generation, lower long term costs, and provide additional options for customers to manage their energy costs. To further mitigate these bill impacts, there are a range of policy tools that could be applied.

Statewide Rates

As shown in the three PSIPs, the average monthly bill for an average full service residential customer for the three operating utilities vary under DG 2.0 in terms of both magnitude and timing (Hawaiian Electric: Figure 6-4; Maui Electric: Figure 6-5; and Hawai‘i Electric Light: Figure 6-6).

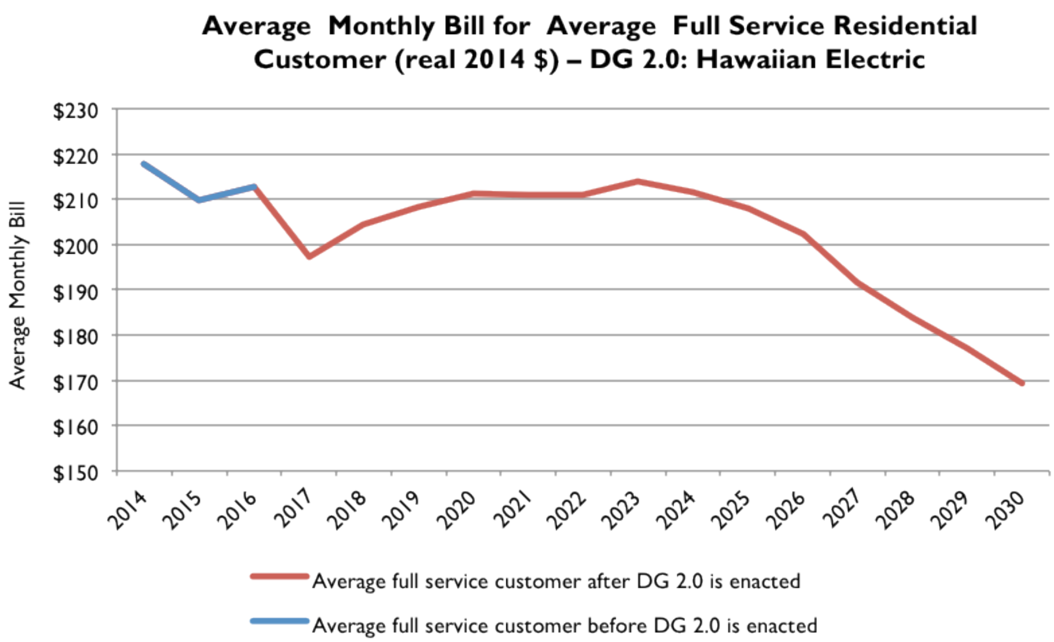

Figure 6-4. Average Monthly Bill for Average Full Service Residential Customer, Hawaiian Electric: DG 2.0

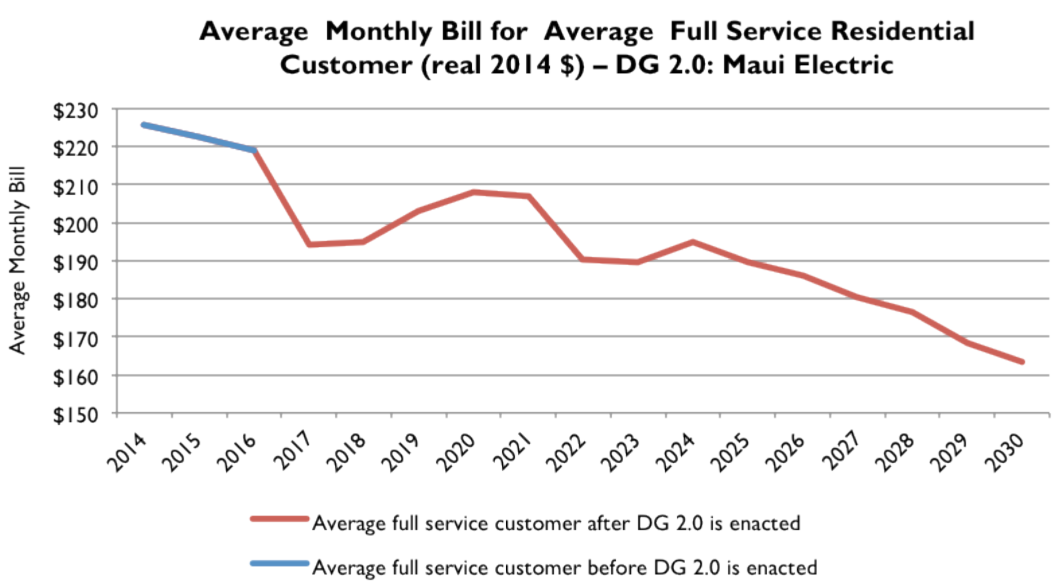

Figure 6-5. Average Monthly Bill for Average Full Service Residential Customer, Maui Electric: DG 2.0

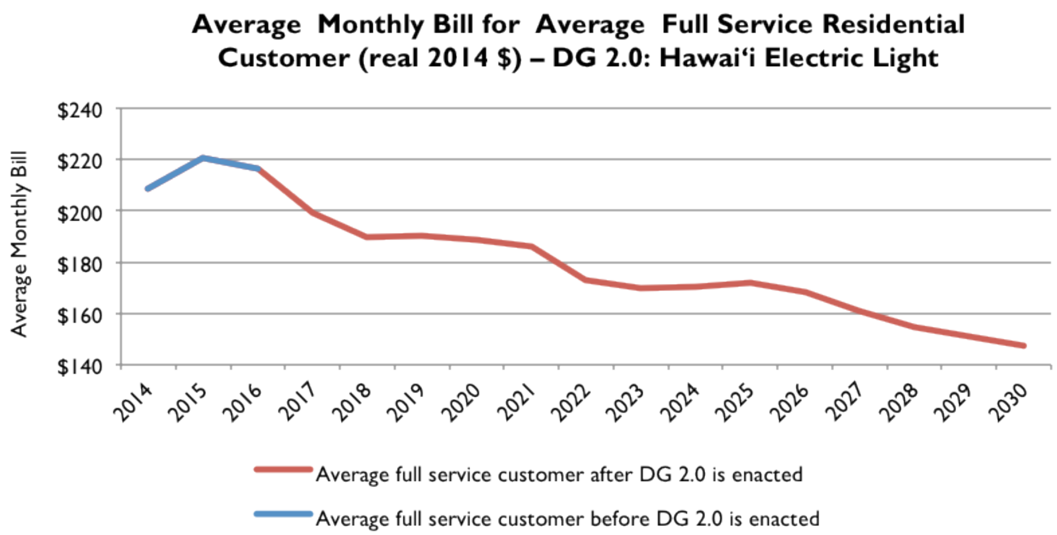

Figure 6-6. Average Monthly Bill for Average Full Service Residential Customer, Hawai'i Electric Light: DG 2.0

A shift toward a statewide rate approach, perhaps beginning with a statewide power supply rate component, would be a tool to smooth out changes impacting individual grids. This approach would also be logical given the "statewide" nature of the RPS goals.

In addition, moving to statewide rates would likely create regulatory efficiencies which would also serve to mitigate rate increases. For example, costs should be reduced by filing a single rate case every three years, rather than filing three rate cases every three years.

Transportation Electrification Incentives

Accelerating the growth of the electric vehicle (EV) market in Hawai'i represents a significant opportunity to impact state emission policy goals, while having a positive impact on the cost of electricity by spreading the fixed costs of the grid over larger usage, and by developing a large load eligible for demand response. Electric vehicles can develop into a sizable, flexible, incremental load. Each of these attributes contributes to helping reduce long-term energy costs. State policy adjustments, such as expanded incentives for purchasing EVs, could help further the reduction of long-term energy costs.

As a new incremental load, EVs are unlikely to drive new, large investments in the grid. Thus, it is likely that the marginal T&D cost to serve EV load is very modest[44], so energy sales for EVs would help lower the cost of the grid to other, non-EV customers.

State Tax Policy

There are a number of ways in which alternative State tax policy can potentially help mitigate electricity prices. Two potential opportunities are described below.

Today, approximately 9% of the average customer bill is comprised of taxes other than income taxes. The investment plans contained in this PSIP will result in the deployment of over $1.1 Billion in capital over the 2015 through 2030 time period. A limited duration excise tax exemption for certain types of investments (such as energy storage) would help reduce the impact on electric customers, while leaving state tax receipts at traditionally expected levels.

Another aspect of tax policy to be considered is the various revenue taxes the Company's customers pay. These taxes automatically increase with any increase in bills, such as the near-term increases driven by the PSIP and DGIP transformational investments. However, any change in the Public Utilities fee component of revenue taxes must be made in light of the need for additional funds required for the Commission and Consumer Advocate to implement regulatory changes.

PROJECTED REVENUE REQUIREMENTS FOR THE PERIOD 2015–2030

The bill reductions discussed in the previous sections are made possible by projected changes in the underlying cost structures. These changes, discussed in terms of overall revenue requirements, are discussed below.

A utility's revenue requirement is the level of gross revenue that enables it to cover all of its prudently incurred expenses and allows it the opportunity to earn a fair return on its invested capital. The major cost elements that contribute to the total revenue requirement include:

- Fuel expense
- Purchased eower expense
- Operations and maintenance expense

[44] This would remain true as long as EV charging is done at times of high renewable generation, allowing excess generation to be used. The cost of an infrastructure and DR controls to achieve this end is not included in the PSIP analysis.

- Depreciation expense
- Interest expense
- Taxes (revenue and income)
- Return on equity investment

Each revenue requirements is discussed in greater detail below.

Projected Revenue Requirements

As illustrated in Figure 6-7, the total Hawai'i Island revenue requirement increases from 2014 to 2015 in real terms, and then decreases significantly from 2024 forward, such that total revenue requirements are declining in real terms over the 2014 through 2030 period.

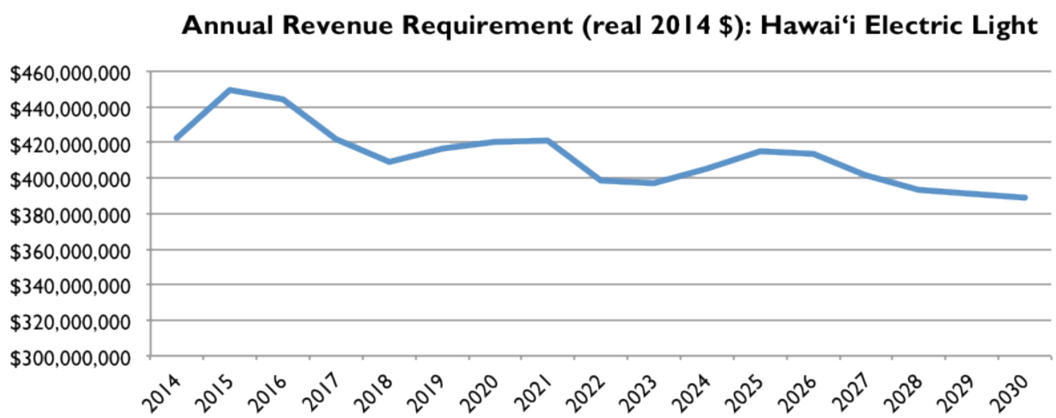

Figure 6-7. Hawai'i Island Annual Revenue Requirement

The balance of this section explores the drivers of the changes in total revenue requirements.

To understand the drivers of the long-term reductions in revenue requirements in real terms, Figure 6-8 provides a breakdown of the annual revenue requirement into its major components.

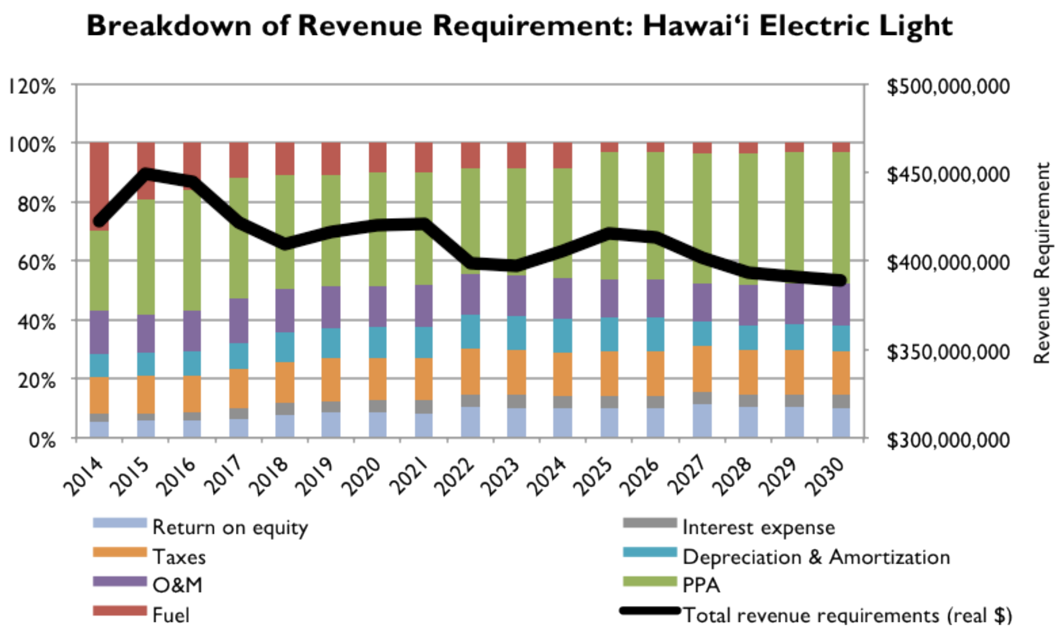

Figure 6-8. Hawai'i Island Annual Revenue Requirement by Major Component

Fuel expense declines significantly over the period, driven by the continued shift toward renewable generation and the cost savings from the introduction of LNG, beginning in 2017.

Power Purchase Agreement costs increase over the period, reflecting both the expanding purchases of renewables and the capacity costs for replacement dispatchable generation.

O&M remains unchanged in real terms across the period.

Depreciation expense grows over the period, driven by both the transformational and foundational investments in the grid and the costs associated with retirement of existing generating units.

Interest expense grows over the period, driven by higher levels of investment and rising interest rates for long term debt.

Tax expense, including revenue and income tax, increases over the period, driven in part by increased income tax expense associated with the increased equity investment. The excise taxes associated with the significant transformational and foundational investments to be made by the Company and others over the 2015–2025 period will be significantly higher than excise taxes associated with Company activities over the 2010–2014 period. The impact of this higher level of tax payments is reflected in the total cost of the new capital investments and is included in the PPA, depreciation, and return on capital cost elements in Figure 6-9. The corresponding state tax credit is amortized over 48 years and so the benefit is only partially realized in the forecast period.

The growth in *return on equity investments* and, as mentioned above, the interest expense, is driven by the capital investment profile of foundational and transformational investments, shown in Figure 6-9.

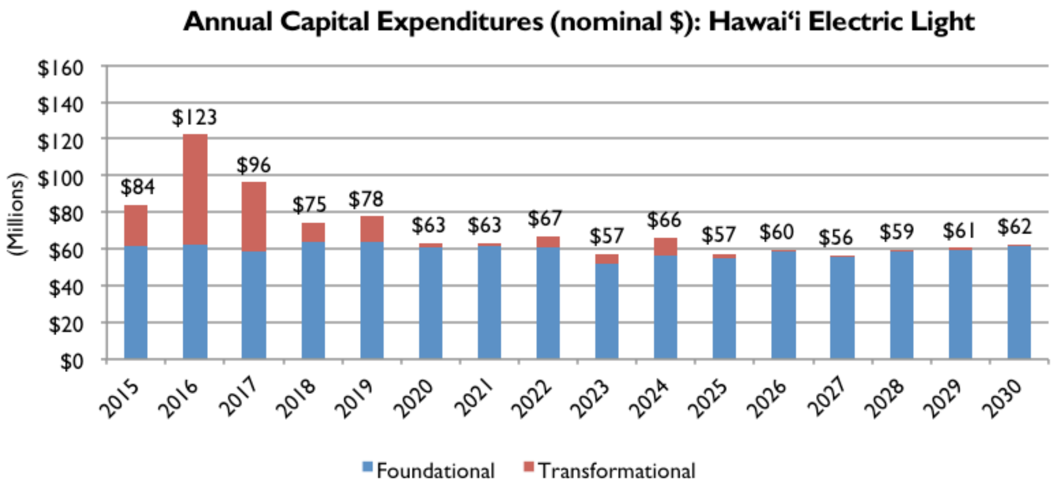

Figure 6-9. Hawai'i Island Foundational and Transformational Capital Expenditures by Year

This profile reflects the basic fact that transformational investments need to be made in advance of each of major changes to the Hawai'i Island grid. The LNG transportation, re-gasification and unit modification investments must be made to enable the LNG fuel savings. Rapid reacting contingency storage and other grid enhancements are necessary to ensure system reliability with current levels of DG-PV, as well as being required to enable DG-PV growth over the next five to seven years. Replacement dispatchable resources must be built or sourced in advance of any additional unit deactivations and retirements. Smart Grid capabilities must be built to enable dynamic pricing.

Securitization

One tool that can help reduce the revenue requirement would be the use of a securitization mechanism to deal with retired generating units. This technique has been widely used elsewhere in the industry to deal with stranded costs.45 One way it could be applied in Hawai'i to lower revenue requirements and reduce costs to our customers would be to re-finance upon retirement the net book value of a generating unit, plus any un-accrued for removal costs, fully with securitized debt. The cash flow to repay the debt would come from a specially designated, non-bypassable customer charge. Figure 6-10 shows the revenue requirement reduction that can be achieved through securitization, assuming it was re-financed at 5% and repaid over 20 years, for each of the units planned to be retired through this PSIP.

[45] Including states such as Texas, Pennsylvania, and New Jersey among many others.

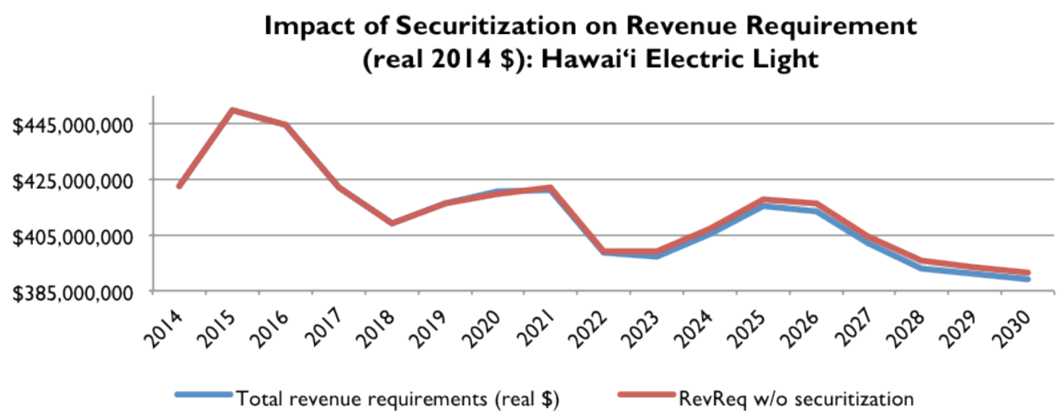

Figure 6-10. Impact of Securitization on Projected Hawai'i Island Revenue Requirement

Given that retirement of existing generation is a key policy objective and that there has been acknowledgement of the need to deal with stranded costs by both the legislature and the Commission, the Company believes that planning for the availability of this tool is reasonable. Therefore, the customer bill impact analysis presented at the start of this chapter assumes that the projected revenue requirement has been reduced by securitization, as shown in Figure 6-10 above.

CONCLUSION

The PSIP identifies those transformational and foundational investments required to build the necessary flexible, smart and renewable energy needed to reliably serve customers across Hawai'i Island. Under the current rate design, while electricity bills for average full service residential customers will increase in the short-run, by 2030, electric bills will be reduced by 22% in real terms from 2014 levels under the current tariff structure and by 30% under DG 2.0.

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7. Conclusions and Recommendations

Hawaiian Electric, Maui Electric, and Hawai‘i Electric Light are pleased to present their Power Supply Improvement Plans (PSIPs).

CONCLUSIONS

1. **Renewable Portfolio Standard (RPS).** Hawai‘i's policy goals will be achieved due to unprecedented levels of renewable energy on each island by 2030.
   - **a.** For the Hawaiian Electric Companies, the consolidated renewable content of electricity increases to approximately 67%.
   - **b.** Hawai‘i Electric Light's PSIP increases renewable content of electricity for Hawai‘i Island to approximately 92%.
   - **c.** Maui Electric's PSIP increases renewable content of electricity for Maui County to approximately 72%.
   - **d.** Hawaiian Electric's PSIP increases renewable content of electricity for O‘ahu to approximately 61%.
2. **Customer Bill Impact Is Beneficial.** The Preferred Plan coupled with changes in rate design that more fairly allocates fixed grid costs across all customers (assumed effective in 2017) is expected to reduce monthly bills for average residential customers from 2014 to 2030 by:
   - **a.** 28% for Maui Electric
   - **b.** 30% for Hawai‘i Electric Light
   - **c.** 22% for Hawaiian Electric

3. **Distributed Solar PV.** For all three operating companies, the PSIP will result in a nearly three-fold increased in solar distributed generation (DG-PV).

4. **Demand Response.** The PSIP will utilize the demand response programs defined in the Companies recently issued *Integrated Demand Response Portfolio Plan* (IDRPP)[46] as integral tools for system operations, and to provide ways for customers to save money on their electric bills by reducing their usage at certain times.

5. **Energy Storage.** The Companies will utilize energy storage system for multiple purposes, and maximize the utilization of renewable energy that is available on the power systems. Storage will be used as "fast-responding" regulating and contingency reserves for system operation.
   a. "Load-shifting" energy storage, including pumped storage hydro and flow batteries, are not currently cost-effective and are not included in our Preferred Plan. In the future, this type of energy storage may prove to be cost-effective and beneficial.

6. **Liquefied Natural Gas (LNG).** LNG play a critical role in the Preferred Plans for all three operating companies, providing for significant cost savings, environmental compliance, and enhanced operational flexibility.

7. **High Utilization of Renewable Energy Resources.** The available energy from renewable resources will be utilized at extremely high levels from 2015 through 2030. This is accomplished by installing energy storage to provide regulating and contingency reserves, using demand response as a tool for better managing system dispatch, selecting future thermal generation resources that have a high degree of operational flexibility, increasing the operational flexibility of existing thermal generation not slated for retirement during the study period, and reducing the "must-run" requirements of thermal generators. The following annual amounts of renewable energy will be utilized (not curtailed) annually:
   a. Maui Electric achieves at least 97.0%
   b. Hawai'i Electric Light achieves at least 96.1%
   c. Hawaiian Electric achieves at least 97.3%

8. **Diverse Generation Resource Mix.** Achieving unprecedented levels of renewable energy, reliable electric service, high utilization of available renewable energy depends on a diverse mix of generation resources and energy storage systems, and judicious use of demand response programs.

[46] The Companies filed their IDRPP with the Commission on July 28, 2014.

9. **Role of Thermal Generation.** Firm and dispatchable thermal generators provide a critical role complementing the renewable energy resources in the generation mix, including a provision of critical grid services for system reliability, and back-up generation for when variable renewable resources are unavailable (for example, hours of darkness, extended cloudiness, or absence of wind).

10. **Retirement of Existing Oil-fired Steam Generators.** During the PSIP planning period of 2015–2030, all of the existing oil-fired steam generators will be retired, or converted to LNG and then retired, including:

    a. Maui Electric: Kahului Units 1–4

    b. Hawai'i Electric Light: Hill Units 5 & 6 and Puna Steam

    c. Hawaiian Electric: Kahe Units 1–6 and Waiau Units 3–8

11. **O'ahu–Maui Grid Tie.** A grid tie connecting the electric grids of O'ahu and Maui would not be cost effective.

RECOMMENDATIONS

We recommend that the Commission, interveners, and participants in Docket 2014-0183, carefully consider the thoughtful and thorough analyses presented in this PSIP. We commit to an honest and thorough discussion of the matters discussed herein.

In the meantime, there are certain initiatives that are already underway that are integral parts of the Preferred Plan. In particular, we will continue to work with stakeholders to address distributed generation interconnection requirements in order to realize the aggressive DG-PV goals included in the Preferred Plan, and as outlined in the *Distributed Generation Interconnection Plan* (DGIP) filed concurrently with this PSIP. All of the ongoing initiatives are the subject of existing docketed proceedings before the Commission. We will continue to move forward with those initiatives as directed by the Commission.

We pledge to work collaboratively with key stakeholders during the regulatory review process so that together, we will achieve success in the transformation outlined in this PSIP.

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A. Commission Order Cross Reference

In Docket No. 2012-0212, Order No. 31758, the Hawai'i Public Utilities Commission ordered Hawaiian Electric:

> "to file a Power Supply Improvement Plan (PSIP) with the commission within 120 days of the date of this Decision and Order…"[47]

The Order listed a number of component plans, each with a number of issues to consider. The Order also listed other stipulations—energy storage and ancillary services—to be analyzed and evaluated.

Presented here is a cross reference between the issues raised in the Commission's Order and the locations in this PSIP where they are addressed.

COMPONENT PLANS

Plan	PSIP Heading	Page
Fossil Generation Retirement Plan	Plan for Retiring Fossil Generation	5-16
Generation Flexibility Plan	Plan for Increasing Generation Flexibility	5-13
Must-Run Generation Reduction Plan	Plan for Increasing Generation Flexibility	5-13
Generation Commitment and Economic Dispatch Review	Appendix N	N-1

Table A-1. Component Plan Cross Reference

[47] Docket No. 2012-0212, Order No. 31758, Section V. E. 6. 7.; p112.

FURTHER ACTION: ENERGY STORAGE

Plan	PSIP Heading	Page
Further Action: Energy Storage[48]	Energy Storage Plan Appendix J	20 J-1

Table A-2. Further Action: Energy Storage Cross Reference

[48] Docket No. 2011-0206, Order No. 32053; Section II. C. 2. v. 1.; p107.

B. Glossary and Acronyms

This Glossary and Acronym Appendix contains the terms used throughout the Power Supply Improvement Plan (PSIP), the Distributed Generation Interconnection Plan (DGIP), and the Integrated Interconnection Queue (IIQ). The Appendix clarifies the meaning of these terms, and helps you better understand the concepts described by these terms.

A

Adequacy of Supply

The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Advanced DER Technology Utilization Plan (ADERTUP)

A plan within the Distributed Generation Improvement Plan (DGIP) that sets forth the near, medium, and long-term plans by which customers would install, and utilities would utilize, advanced technologies to mitigate adverse grid impacts of distributed generation (DG) photovoltaics (PV).

Advanced Distribution Management System (ADMS)

A single system that includes an Outage Management System (OMS), Distribution Management System (DMS), and Distribution SCADA components and functionalities all in one platform, with a single user interface for the operator. ADMS will be used to help manage and integrate the new technologies and applications to be deployed as part of the utility's grid modernization program.

Advanced Inverter

A smart inverter capable of being interconnected to the utility (via two-way communications) and controlled by it.

Advanced Metering Infrastructure (AMI)

A primary component of a modern grid that provides two-way communications between the customer premises and the utility. An AMI is a necessary prerequisite to the interactions with advanced inverters, customer sited storage, demand response through direct load control, and EVs.

Alternating Current (AC)

An electric current whose flow of electric charge periodically reverses direction. In Hawai'i, the mainland United States, and in many other developed countries, AC is the form in which electric power is delivered to businesses and residences. The usual waveform of an AC power circuit is a sine wave. In Hawai'i and the mainland United States, the usual power system frequency of 60 hertz (1 hertz (Hz) = 1 cycle per second).

Ancillary Services

Services that supplement capacity as needed in order to meet demand or correct deviations in frequency. These include reserves, black start resources, and frequency response.

As-Available Renewable Energy

See Variable Renewable Energy on page B-35.

Avoided Costs

The costs that utility customers would avoid by having the utility purchase capacity and/or energy from another source (for example, energy storage or demand response) or from a third party, compared to having the utility generate the electricity itself. Avoided costs comprise two components:

- Avoided capacity costs, which includes avoided capital costs (for example, return on investment, depreciation, and income taxes) and avoided fixed operation and maintenance costs.
- Avoided energy costs, which includes avoided fuel costs and avoided variable operation and maintenance costs.

B

Baseload

The minimum electric or thermal load that is supplied continuously over a period of time. See also Load, Electric on page B-19.

Baseload Capacity

See Capacity, Generating on page B-4.

Baseload Generation

The production of energy at a constant rate, to support the system's baseload.

Battery Energy Storage Systems (BESS)

Any battery storage system used for contingency or regulating reserves, load shifting, ancillary services, or other utility or customer functions. See also Storage on page B-31.

Black Start

The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the electric system.

British Thermal Unit (Btu)

A unit of energy equal to about 1055 joules that describes the energy content of fuels. A Btu is the amount of heat required to raise the temperature of 1 pound of water by 1°F at a constant atmospheric pressure. When measuring electricity, the proper unit would be Btu per hour (or Btu/h) although this is generally abbreviated to just Btu. The term MBtu means a thousand Btu; the term MMBtu means a million Btu.

Buy-All/Sell-All

Tariff structure for DER under which customers would sell their entire DG output to the utility and purchase all of their requirements from the utility. This structure requires a two-meter system, with one meter to monitor grid import/export and one to monitor generation from the PV system.

C

Capacitor

A device that helps improve the efficiency of the flow of electricity through distribution lines by reducing energy losses. This is accomplished by the capacitor's ability to correct AC voltage so that the voltage is in phase with the AC current. Capacitors are typically installed in substations and on distribution system poles.

Capacity Factor (cf)

The ratio of the average operating load of an electric power generating unit for a period of time to the capacity rating of the unit during that period of time.

Capacity, Generating

The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of an electric generating plant. It is the maximum power that a machine or system can produce or carry under specified conditions, usually expressed in kilowatts or megawatts. Capacity is an attribute of an electric generating plant that does not depend on how much it is used. Types of capacity include:

Baseload Capacity: Those generating facilities within a utility system that are operated to the greatest extent possible to maximize system mechanical and thermal efficiency and minimize system operating costs. Baseload capacity typically operates at high annual capacity factors, for example greater than 60%.

Firm Capacity: Capacity that is intended to be available at all times during the period covered by a commitment, even under adverse conditions.

Installed Capacity (ICAP): The total capacity of all generators able to serve load in a given power system. Also called ICAP, the total wattage of all generation resources to serve a given service or control area.

Intermediate Capacity: Flexible generators able to efficiently vary their output across a wide band of loading conditions. Also known as Cycling Capacity. Typically annual capacity factors for intermediate duty generating units range from 20% to 60%.

Net Capacity: The maximum capacity (or effective rating), modified for ambient limitations, that a generating unit, power plant, or electric system can sustain over a specified period, less the capacity used to supply the demand of station service or auxiliary needs.

Peaking Capacity: Generators typically called on for short periods of time during system peak load conditions. Annual capacity factors for peaking generation are typically less than 20%.

Capital Expenditures

Funds expended by a utility to construct, acquire or upgrade physical assets (generating plants, energy storage devices, transmission plant, distribution plant, general plant, major software systems, or IT infrastructure). Capital expenditures for a given asset include funds expended for the acquisition and development of land related to the asset, obtaining permits and approvals related to the asset, environmental and engineering studies specifically related to construction of the asset, engineering design of the asset, procurement of materials for the asset, construction of the asset, and startup activities related to the asset. Capital expenditures may be associated with a new asset or an existing asset (that is, renovations, additions, upgrades, and replacement of major components).

Carbon Dioxide (CO_2)

A greenhouse gas produced when carbon-based fossil fuels are combusted.

Combined Cycle (CC)

A combination of combustion turbine- and steam turbine-driven electrical generators, where the combustion turbine exhaust is passed through a heat recovery waste heat boiler which, in turn, produces steam which drives the steam turbine.

2x1 Combined Cycle: A configuration in which there are two combustion turbines, one heat recovery waste heat boiler, and one steam turbine. The combustion turbines produce heat for the single waste heat boiler, which in turn produces steam that is directed to the single steam turbine.

Dual-Train Combined Cycle (DTCC): A configuration in which there are two combustion turbines, two heat recovery waste heat boilers and one steam turbine. Each combustion turbine/waste heat boiler combination produces steam that is directed to the single steam turbine.

Single-Train Combined Cycle (STCC): A configuration in which there is one combustion turbine, one heat recovery waste heat boiler, and one steam turbine.

Combined Heat and Power (CHP)

The simultaneous production of electric energy and useful thermal energy for industrial or commercial heating or cooling purposes. The Energy Information Administration (EIA) has adopted this term in place of cogeneration.

Combustion Turbine (CT)

Any of several types of high-speed generators using principles and designs of jet engines to produce low cost, high efficiency power. Combustion turbines typically use natural gas or liquid petroleum fuels to operate.

Commercial and Industrial Direct Load Control (CIDLC)

A demand response program that provides financial incentives to qualified businesses for participating in demand control events. Such a program is designed for large commercial and industrial customers.

Commercial and Industrial Dynamic Pricing (CIDP)

A demand response program that provides tariff-based dynamic pricing options for electrical power to commercial and industrial customers. CIDP encourages customers to reduce demand when the overall load is high.

Conductor Sag

The distance between the connection point of a conductor (transmission/distribution line) and the lowest point of the line.

Connected Load

See Load, Electric on page B-19.

Contingency Reserve

The reserve deployed to meet contingency disturbance requirements, the largest single resource contingency on each island.

Curtailment

Cutting back on variable resources during off-peak periods of low electricity use in order to keep generation and consumption of electricity in balance.

D

Daytime Minimum Load (DML)

The absolute minimum demand for electricity between 9 AM and 5 PM on one or more circuits each day.

Demand

The rate at which electricity is used at any one given time (or averaged over any designated interval of time). Demand differs from energy use, which reflects the total amount of electricity consumed over a period of time. Demand is often measured in Kilowatts (kW = 1 Kilowatt = 1000 watts), while energy use is usually measured in Kilowatt-hours (kWh = Kilowatts x hours of use = Kilowatt-hours). Load is considered synonymous with demand. (See also Load, Electric on page B-19.)

Demand Charge

A customer charge intended to allocate fixed grid costs to customers based on each customer's consumption demand.

Demand Response (DR)

Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized. The underlying objective of demand response is to actively engage customers in modifying the demand for electricity, in lieu of a generating plant supplying the demand.

> ***Load Control:*** Includes direct control by the utility or other authorized third party of customer end-uses such as air conditioners, lighting, and motors. Load control may entail partial or load reductions or complete load interruptions. Customers usually receive financial consideration for participation in load control programs.
>
> ***Price Response:*** Refers to programs that provide pricing incentives to encourage customers to change their electricity usage profile. Price response programs include real-time pricing, dynamic pricing, coincident peak pricing, time-of-use rates, and demand bidding or buyback programs.

Demand-Side Management (DSM)

The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. It refers only to energy and load-shape modifying activities that are undertaken in response to utility or third party-administered programs. It does not refer to energy and load-shape changes arising from the normal operation of the marketplace or from government-mandated energy efficiency standards. Demand--Side Management (DSM) covers the complete range of load-shape objectives, including strategic conservation and load management, as well as strategic load growth.

Department of Business, Economic Development, & Tourism (DBEDT)

Hawai'i's resource center for economic and statistical data, business development opportunities, energy and conservation information, and foreign trade advantages. DBEDT's mission is to achieve a Hawai'i economy that embraces innovation and is globally competitive, dynamic and productive, providing opportunities for all Hawai'i's citizens. Through our attached agencies, we also foster planned community development, create affordable workforce housing units in high-quality living environments, and promote innovation sector job growth.

Department of Land and Natural Resources (DLNR)

A department within the Hawai'i state government responsible for managing state parks and other natural resources.

Direct Current (DC)

A department within the Hawai'i state government responsible for managing Hawai'i's unique natural and cultural resources. Also oversees state-owned and state conservation lands.

Distributed Energy Resources Technical Working Group (DER-TWG)

A working group to be formed as a review committee for DER-related technical assessments.

DG 2.0

A generic term used to describe revised tariff structures governing export and non-export models, based on fair allocation of costs among distributed generation (DG) customers and traditional retail customers, and fair compensation of DG customers for energy provided to the grid.

Direct Current (DC)

An electric current whose flow of electric charge remains constant. Certain renewable power generators (such as solar PV) deliver DC electricity, which must be converted to AC electricity, using an inverter, for use in the power system.

Direct Load Control (DLC)

This Demand-Side Management category represents the consumer load that can be interrupted by direct control of the utility system operator. For example, the utility may install a device such as a radio-controlled device on a customer's air-conditioning equipment or water heater. During periods of system need, the utility will send a radio signal to the appliance with this device and control the appliance for a set period of time.

Direct Transfer Trip

A protection mechanism that originates from station relays in response to a substation event.

Dispatchable Generation

A generation source that is controlled by a system operator or dispatcher who can increase or decrease the amount of power from that source as the system requirements change.

Distributed Circuit Improvement Implementation Plan (DCIIP)

A plan within the Distributed Generation Interconnection Plan (DGIP) that summarizes the specific strategies and action plans, including associated costs and schedules, to implement circuit upgrades and other mitigation measures to increase capacity of electrical grids to interconnect additional distributed generation.

Distributed Energy Resources (DER)

Non-centralized generating and storage systems that are co-located with energy load.

Distributed Energy Storage

Energy storage systems sited on the distribution circuit, including substation-sited and customer-sited storage.

Distributed Generation (DG)

A term referring to a small generator, typically 10 megawatts or smaller, that is sited at or near load, and that is attached to the distribution grid. Distributed generation can serve as a primary or backup energy source and can use various technologies, including combustion turbines, reciprocating engines, fuel cells, wind generators, and photovoltaics. Also known as a Distributed Energy Resource (see page B-9).

Distributed Generation Interconnection Capacity Analysis (DGICA)

A plan within DGIP to proactively identify distribution circuit capacity constraints to the safe and reliable interconnection of distributed generation resources. Includes system upgrade requirements necessary to increase circuit interconnection capability in major capacity increments.

Distribution Automation (DA)

Programs to allow monitoring and control of all distribution level sources, as well as the automation of feeders to provide downstream monitoring and control.

Distribution Circuit Monitoring Program (DCMP)

A document filed by the Companies on June 27, 2014, outlining three broad goals. First, to measure circuit parameters to determine the extent to which distributed solar photovoltaic (PV) generation is causing safety, reliability, or power quality issues. Second, to ensure that distributed generation circuit voltages are within tariff and applicable standards. Third, to increase the Companies' knowledge of what is occurring on high PV penetration circuits to determine boundaries and thresholds and further future renewable DG integration work.

Distribution Circuit

The physical elements of the grid involved in carrying electricity from the transmission system to end users.

Distribution Transformer

A transformer used to step down voltage from the distribution circuit to levels appropriate for customer use.

Disturbance Ride-Through

The capability of DG systems to remain connected to the grid under non-standard voltage levels.

Droop

The amount of speed (or frequency) change that is necessary to cause the main prime mover control mechanism to move from fully closed to fully open. In general, the percent movement of the main prime mover control mechanism can be calculated as the speed change (in percent) divided by the per unit droop.

Dual-Train Combined Cycle (DTCC)

See Combined Cycle on page B-5.

E

Economic Dispatch

The start-up, shutdown, and allocation of load to individual generating units to effect the most economical production of electricity for customers.

Electric Power Research Institute (EPRI)

A nonprofit research and development organization that conducts research, development and demonstration relating to the generation, delivery, and use of electricity.

Electric Vehicle (EV)

A vehicle that uses one or more electric motors or traction motors for propulsion.

Electricity

The set of physical phenomena associated with the presence and flow of electric charge.

Energy

The ability to produce work, heat, light, or other forms of energy. It is measured in watt-hours. Energy can be computed as capacity or demand (measured in watts), multiplied by time (measured in hours). For example, a 1 megawatt (one million watts) power plant running at full output for 1 hour will produce 1 megawatt-hour (one million watt-hours or 1000 kilowatt-hours) of electrical energy.

Emissions

An electric power plant that combusts fuels releases pollutants to the atmosphere (for example, emissions of sulfur dioxide) during normal operation. These pollutants may be classified as primary (emitted directly from the plant) or secondary (formed in the atmosphere from primary pollutants). The pollutants emitted will vary based on the type of fuel used.

Energy Efficiency DSM

Programs designed to encourage the reduction of energy used by end-use devices and systems. Savings are generally achieved by substituting more technologically advanced equipment to produce the same level of energy services (for example, lighting, water heating, motor drive) with less electricity. Examples include programs that promote the adoption of high-efficiency appliances and lighting retrofit programs through the offering of incentives or direct install services.

Energy Efficiency Portfolio Standard (EEPS)

A goal for reducing the demand for electricity in Hawai'i through the use of energy efficiency and displacement or offset technologies set by state law. The EEPS goes into effect in January 2015. Until then, energy savings from these technologies are included in the calculations for Hawai'i's RPS. The EEPS for Hawai'i provides for a total energy efficiency target of 4,300,000 megawatt-hours per year by the year 2030. To the extent that this target is achieved, this quantity of electric energy will not be served by Hawai'i's electric utilities. Therefore, the projected amount of energy reductions due to energy efficiency are removed from the system energy requirement forecasts used in this PSIP.

Energy Excelerator

A program of the Pacific International Center for High Technology Research that funds seed-stage and growth-stage startups with compelling energy solutions and immediate applications in Hawaiʻi, helping them succeed by providing funding, strategic relationships, and a vibrant ecosystem.

Energy Management System (EMS)

A computer system,including data-gathering tools used to monitor and control electrical generation and transmission.

Expense

An outflow of cash or other consideration (for example, incurring a commercial credit obligation) from a utility to another person or company in return for products or services (fuel expense, operating expense, maintenance expense, sales expense, customer service expense, interest expense.). An expense might also be a non-cash accounting entry where an asset (created as a result of a Capital Expenditure) is used up (for example, depreciation expense) or a liability is incurred.

Export Model

A model for DG PV interconnection in which co-incident self-generation and usage is not metered, excess energy is exported to the grid, and energy is imported to meet additional customer needs.

F

Feeder

A circuit carrying power from a major conductor to a one or more distribution circuits.

Firm Capacity

See Capacity, Generating on page B-4.

Feed-In-Tariff (FIT) Program

A FIT program specific to Hawaiian Electric, under guidelines issued by the Hawaiʻi Public Utilities Commission, which provides for customers to sell all the electric energy produced to the electric company.

Feed-In-Tariff (FIT)

The generic term for the rate at which exported DG PV is compensated by the utility.

First-In-First-Out (FiFo)

The policy for clearing the DG interconnection queues, under which applications are processed in the order in which they were received.

Flicker

An impression of unsteadiness of visual sensation induced by a light stimulus whose luminance or spectral distribution fluctuates with time.

Flywheel

See Storage one page B-31.

Forced Outage

See Outage on page B-23.

Forced Outage Rate

See Outage on page B-23.

Fossil Fuel

Any naturally occurring fuel formed from the decomposition of buried organic matter, essentially coal, petroleum (oil), and natural gas. Fossil fuels take millions of years to form, and thus are non-renewable resources. Because of their high percentages of carbon, burning fossil fuels produces about twice as much carbon dioxide (a greenhouse gas) as can be absorbed by natural processes.

Frequency

The number of cycles per second through which an alternating current passes. Frequency has been generally standardized in the United States electric utility industry at 60 cycles per second (60 Hz). The power system operator strives to maintain the system frequency as close as possible to 60 Hz at all times by varying the output of dispatchable generators, typically through automatic means. In general, if demand exceeds supply, the frequency will drop below 60 Hz; if supply exceeds demand, the frequency will rise above 60 Hz. If the system frequency drops to an unacceptable level (under-frequency), or rises to an unacceptable level (over-frequency), a system failure can occur. Accordingly, system frequency is an important indicator of the power system's condition at any given point in time.

Frequency Regulation

The effort to keep an alternating current at a consistent 60 Hz per second (or other fixed standard).

Full-Forced Outage

See Outage on page B-23.

Full Service Customer

Any residential or commercial customer that imports the entirety of their energy demands from the grid, and does not self-consume or export any energy derived from distributed energy resources co-located with their load.

G

Generating Capacity

See Capacity, Generating on page B-4.

Generation (Electricity)

The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatt-hours (kWh) or megawatt hours (MWh).

Nameplate Generation (Gross Generation): The electrical output at the terminals of the generator, usually expressed in megawatts (MW).

Net Generation: Gross generation minus station service or unit service power requirements, usually expressed in megawatts (MW). The energy required for pumping at a pumped storage plant is regarded as plant use and must be deducted from the gross generation.

Generator (Electric)

A machine that transforms mechanical, chemical, or thermal energy into electric energy. Includes wind generators, solar PV generators, and other systems that convert energy of one form into electric energy. See also Capacity, Generating on page B-4.

Geographic Information System (GIS)

A computer system designed to capture, store, manipulate, analyze, manage, and present all types of geographical data.

Gigawatt (GW)

A unit of power, capacity, or demand equal to one billion watts.

Gigawatt-hour (GWh)

A unit of electric energy equal to one billion watt-hours.

Grandfather

To exempt a class of customers from changes to the laws or regulations under which they operate.

Greenhouse Gases (GHG)

Any gas whose absorption of solar radiation is responsible for the greenhouse effect, including carbon dioxide, methane, ozone, and the fluorocarbons.

Grid (Electric)

An interconnected network of electric transmission lines and related facilities.

Grid Modernization

The full suite of technologies and capabilities—including the data acquisition capabilities, controlling devices, telecommunications, and control systems—necessary to operate the utility's modernized electric grid. This includes Advanced Metering Infrastructure (AMI) with two-way communications and all the components to implement an Advanced Distribution Management System/Energy Management System. Additional components might include Volt-VAR Optimization (VVO); demand response; control of DG (curtailment and other); adaptive relaying (dynamic load shed); transformer monitoring; and potentially other advanced analytics, reporting, and monitoring capabilities.

Gross Generation

See Generation (Electricity) on page B-14.

Ground Fault Overvoltage

A transient overvoltage issue that occurs when the neutral of a wye grounded system shifts, causing a temporary overvoltage on the unfaulted phase.

Grounding Transformer

A transformer that provides a safe path to ground.

H

Hawai'i Public Utilities Commission (PUC)

A state agency that regulates all franchised or certificated public service companies operating in Hawai'i. The PUC prescribes rates, tariffs, charges and fees; determines the allowable rate of earnings in establishing rates; issues guidelines concerning the general management of franchised or certificated utility businesses; and acts on requests for the acquisition, sale, disposition or other exchange of utility properties, including mergers and consolidations.

Hawai'i Revised Statute (HRS)

The codified laws of the State of Hawai'i. The entire body of state laws is referred to the Hawai'i Revised Statutes; the abbreviation HRS is normally used when citing a particular law.

Heat Rate

A measure of generating station thermal efficiency, generally expressed in Btu per net kilowatt-hour. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting net kilowatt-hour generation.

High Voltage Direct Current (HVDC)

An electric power transmission system that uses direct current, rather than alternating current, for bulk transmission.

I

Impacts

The positive or negative consequences of an activity. For example, there may be negative consequences associated with the operation of power plants from the emission discharge or release of a material to the environment (for example, health effects). There may also be positive consequences resulting from the construction and siting of power plants which could affect society and culture.

Impedance

A measure of the opposition to the flow of power in an AC circuit.

Independent Power Producer (IPP)

Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, co-generators (or combined heat and power generators) and small power producers (including net metered and feed-in-tariff systems) and all other non-utility electricity producers, such as exempt wholesale generators, who sell electricity or exchange electricity with the utility. IPPs are also sometimes referred to as non-utility generators (NUGs).

Installed Capacity

See Capacity, Generating on page B-4.

Integrated Demand Response Portfolio Plan (IDRPP)

A Comprehensive Demand Response program proposal filed by the Companies with the Hawai'i Public Utilities Commission on July 28, 2014.

Integrated Interconnection Queue (IIQ)

Recommendations and plan for implementing and organizing an Integrated Interconnection Queue across all DG programs as directed by the Hawai'i Public Utilities Commission in Order 32053, to be filed on August 26, 2014.

Integrated Resource Plan (IRP)

The plan by which electric utilities identify the resources or the mix of resources for meeting near- and long-term consumer energy needs. An IRP conveys the results from a planning, analysis, and decision-making process that examines and determines how a utility will meet future demands. Developed in the 1980s, the IRP process integrates efficiency and load management programs, considered on par with supply resources; broadly framed societal concerns, considered in addition to direct dollar costs to the utility and its customers; and public participation into the utility planning process.

Interconnection Charge

A one-off charge to DG customers reflecting costs of studies and any potential upgrades (such as transformer upgrades) associated with distributed generation.

Interconnection Requirements Study (IRS)

Studies conducted by the Hawaiian Electric Companies on specific DG interconnection requests that may require mitigation measures to ensure circuit stability.

Intermediate Capacity

See Capacity, Generating on page B-4.

Intermittent Renewable Energy

See Variable Renewable Energy on page B-35.

Inverter

A device that converts direct current (DC) electricity to alternating current (AC) either for stand-alone systems or to supply power to an electricity grid. An appropriately designed inverter can provide dynamic reactive power as well as real power and low voltage ride-through capability. A solar PV system uses inverters to convert DC electricity to AC electricity for use in the grid, or directly by a customer.

Islanding

A condition in which a circuit remains powered by non-utility generation (that is, distributed generation resources) even when the circuit has been disconnected from the wider utility power network.

K

Kilowatt (KW)

A unit of power, capacity, or demand equal to one thousand watts. The Companies sometimes express the demand for an individual electric customer, or the capacity of a distributed generator in kilowatts. The standard billing unit for electric tariffs with a demand charge component is the kilowatt.

Kilowatt-hour (KWh)

A unit of electric energy equal to one thousand watt-hours. The standard billing unit for electric energy sold to retail consumers is the kilowatt-hour.

L

Laterals

Lines branching off the primary feeder on a distribution circuit.

Levelized Cost of Energy (LCOE)

The price per kilowatt-hour in order for an energy project to break even; it does not include risk or return on investment.

Life-Cycle Costs

The total cost impact over the life of a program or the life of an asset. Life-cycle costs include Capital Expenditures, operation, maintenance and administrative expenses, and the costs of decommissioning.

Liquefied Natural Gas (LNG)

Natural gas that has been cooled until it turns liquid, in order to make storage and transport easier.

Live-Line Block Closing

Restrictions on the re-closing of feeders with interconnected DG PV systems based on line voltage levels.

Load, Electric

The term load is considered synonymous with demand. Load may also be defined as an end-use device or an end-use customer that consumes power. Using this definition of load, demand is the measure of power that a load receives or requires.

Baseload: The minimum load over a given period of time.

Connected Load: The sum of the capacities or ratings of the electric power consuming apparatus connected to a supplying system, or any part of the system under consideration.

Load Balancing

The efforts of the system operator to ensure that the load is equal to the generation. During normal operating conditions the system operator utilizes load following and frequency regulation for load balancing.

Load Control Program

A program in which the utility company offers some form of compensation (for example, a bill credit) in return for having permission to control a customer's air conditioner or water heater for short periods of time by remote control.

Load Forecast

An estimate of the level of future energy needs of customers in an electric system. Bottom-up forecasting uses utility revenue meters to develop system-wide loads; used often in projecting loads of specific customer classes. Top-down forecasting uses utility meters at generation and transmission sites to develop aggregate control area loads; useful in determining reliability planning requirements, especially where retail choice programs are not in effect.

Load Management DSM

Electric utility or third party marketing programs designed to encourage the utility's customers to adjust the timing of their energy consumption. By coordinating the timing of its customers' consumption, the utility can achieve a variety of goals, including reducing the utility's peak system load, increasing the utility's minimum system load, and meeting unusual, transient, or critical system operating conditions.

Load Profile

Measurements of a customer's electricity usage over a period of time which shows how much and when a customer uses electricity. Load profiles can be used by suppliers and transmission system operators to forecast electricity supply requirements and to determine the cost of serving a customer.

Load Shedding

A purposeful, immediate response to curtail electric service. Load shedding is typically used to curtail large blocks of customer load (for example, particular distribution feeders) during an under frequency event when demand for electricity exceeds supply (for example, during the sudden loss of a generating unit).

Load Tap Changer (LTC)

A substation controller used to regulate the voltage output of a transformer.

Low Sulfur Fuel Oil (LSFO)

A fuel oil that contains less than 500 parts per million of sulfur; about 0.5% sulfur content.

Low Sulfur Industrial Fuel Oil (LSIFO)

A fuel oil that contains up to 7,500 parts per million of sulfur; about 0.75% sulfur content. LSIFO is used by Maui Electric and Hawaiʻi Electric Light if a fuel with lower sulfur content than MSFO is needed.

Low Voltages

Voltages above 0.9 per unit that are of concern because these voltages can become an under voltage violation in the future.

M

Maalaea Power Plant (MPP)

The largest power plant on Maui, with 15 diesel units, a combined cycle gas turbine, and a combined/simple cycle gas turbine totaling 208.42 MW (net) of firm capacity.

Maintenance Outage

See Outage on page B-23.

MBtu

A thousand Btu. See also British Thermal Unit on page B-3.

Medium Sulfur Fuel Oil (MSFO)

A fuel oil that contains between 1,000 and 5,000 parts per million of sulfur; between 1% and 3.5% sulfur content.

Megawatt (MW)

A unit of power, capacity, or demand equal to one million watts. The Companies typically express their generating capacities and system demand in Megawatts.

Megawatt-hour (MWh)

A unit of electric energy equal to one million watt-hours. The Companies from time to time express the energy output of their generators or the amount of energy purchased from Independent Power Producers in megawatt-hours.

MMBtu

One million Btu. See also British Thermal Unit on page B-3.

Modern Grid

An umbrella term used to describe transformed grid, including communications, AMI, ADMS, and DA.

Must Run Unit

A baseload generation facility that must run continually due to operational constraints or system requirements to maintain system reliability; typically a large thermal power plant.

N

N-1 Contingency

A condition that happens when a planned or unplanned outage of a transmission facility occurs while all other transmission facilities are in service. Also known as an N-1 condition.

Nameplate Generation

See Generation (Electricity) on page B-14.

Net Capacity

See Capacity, Generating on page B-4.

Net Energy Metering (NEM)

A financial arrangement between a customer with a renewable distributed generator and the utility, where the customer only pays for the net amount of electricity taken from the grid, regardless of the time periods when the customer imported from or exported to the grid. Under a NEM arrangement, the customer is allowed to remain connected to the power grid, so that the customer can take advantage of the grid's reliability infrastructure (such as ancillary services provided by generators, energy storage devices, and demand response programs), use the grid as a "bank" for power generated by the customer in excess of the customer's needs, and use the grid as a backup resource for times when the power generated by the customer is less than the customer's needs.

Net Generation

See Generation (Electricity) on page B-14.

Nitrogen Oxide (NO_x)

A pollutant and strong greenhouse gas emitted by combusting fuels.

Nominal Value (Nominal Dollars)

While a complex topic, at its most basic, value is based on a measure of money over a period of time. Generally expressed in terms of US dollars, nominal value represents a money cost in a given year, usually the current year. As such, nominal dollars can also be referred to as current dollars.

Non-Export Model

A tariff structure governing the interconnection of non-export DG systems.

Non-transmission alternatives

Programs and technologies that complement and improve operation of existing transmission systems that individually or in combination defer or eliminate the need for upgrades to the transmission system.

North American Electric Reliability Corporation (NERC)

An international regulatory authority whose mission is to ensure the reliability of the bulk power system in North America.

O

Off-Peak Energy

Electric energy supplied during periods of relatively low system demands as specified by the supplier. In general, this term is associated with electric water heating and pertains to the use of electricity during that period when the overall demand for electricity from our system is below normal.

On-Peak Energy

Electric energy supplied during periods of relatively high system demand as specified by the supplier.

Operation and Maintenance (O&M) Expense

The recurring costs of operating, supporting, and maintaining authorized programs, including costs for labor, fuel, materials, and supplies, and other current expenses.

Operating Reliability

The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

Operating Reserves

There are two types of operating reserves that enable an immediate or near immediate response to an increase in demand. (See also Reserve on page B-28.)

> ***Spinning Reserve Service:*** Provides additional capacity from electricity generators that are on-line, loaded to less than their maximum output, and available to serve customer demand immediately should a contingency occur.
>
> ***Supplemental Reserve Service:*** Provides additional capacity from electricity generators that can be used to respond to a contingency within a short period, usually ten minutes.

Outage

The period during which a generating unit, transmission line, or other facility is out of service. The following six terms are types of outages or outage-related terms:

> ***Forced Outage:*** The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons or a condition in which the equipment is unavailable due to unanticipated failure.

Forced Outage Rate: The hours a generating unit, transmission line, or other facility is removed from service, divided by the sum of the hours it is removed from service, plus the total number of hours the facility was connected to the electricity system expressed as a percent.

Full-Forced Outage: The net capability of main generating units that is unavailable for load for emergency reasons.

Maintenance Outage: The removal of equipment from service availability to perform work on specific components that can be deferred beyond the end of the next weekend, but requires the equipment be removed from service before the next planned outage. Typically, a Maintenance Outage may occur anytime during the year, have a flexible start date, and may or may not have a predetermined duration.

Partial Outage: The outage of a unit or plant auxiliary equipment that reduces the capability of the unit or plant without causing a complete shutdown. It may also include the outage of boilers in common header installations.

Planned (or Scheduled) Outage: The shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule.

P

Partial Outage

See Outage on page B-23.

Peak Demand

The maximum amount of power necessary to supply customers; in other words, the highest electric requirement occurring in a given period (for example, an hour, a day, month, season, or year). For an electric system, it is equal to the sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system. From a customer’s perspective, peak demand is the maximum power used during a specific period of time.

Peaker

A generation resource that generally runs to meet peak demand, usually during the late afternoon and early evening when the demand for electricity during the day is highest. It is also referred to as a peaker plant or a peaking power plant.

Peaking Capacity

See Capacity, Generating on page B-4.

Phase imbalance

A condition in which there is a voltage imbalance across two or more phases of a multi-phase system.

Photovoltaic (PV)

Electricity from solar radiation typically produced with photovoltaic cells (also called solar cells): semiconductors that absorb photons and then emit electrons.

Planned Outage

See Outage on page B-23.

Planning Reserve

See Reserve on page B-28.

Plug-in Electric Vehicle (PEV)

An umbrella term encompassing all electric or hybrid electric vehicles that can be recharged through an external electricity source.

Power

The rate at which energy is supplied to a load (consumed), usually measured in watts (W), kilowatts (kW), or megawatts (MW).

Power Factor

A dimensionless quantity that measures the extent to which the current and voltage sine waves in an AC power system are synchronized. If the voltage and current sine waves perfectly match, the power factor is 1.0. Power factors not equal to 1.0 result in dissipation of electric energy into losses.

Power Generating Technology

The myriad ways in which electric power is produced, including both commercially available technologies and emerging technologies, as well as hypothetical technologies.

Power Purchase Agreement (PPA)

A contract for the Hawaiian Electric Companies to purchase energy and or capacity from a commercial source (for example, an Independent Power Producer) at a predetermined price or based on pre-determined pricing formulas.

Present Value

The value of an asset, taking into account the time value of money—a future dollar is worth less today. Present value dollars are expressed in a constant year dollars (usually the current year). Future dollars are converted to present dollars using a discount rate. For example, if someone borrows money from you today, and agrees to pay you back in one year in the amount of $1.00, and the discount rate is 10%, you would be only be willing to loan the other person $0.90 today. Utility planners use present value as a way to directly compare the economic value of multi-year plans with different future expenditure profiles. Net Present Value is the difference between the present value of all future benefits, less the present value of all future costs.

Primary Lines

The main high-voltage lines of the transmission and distribution network.

Proactive Approach

A forward-looking process governing the forecasting of penetration of DER on distribution circuits, analysis of operational constraints, and pre-emptive mitigation of these constraints.

Public Benefits Fee Administrator (PBFA)

A third-party agent that handles energy efficiency rebates and incentives for the Hawaiian Electric Companies.

Pumped Storage Hydro

See Storage on page B-31.

Q

Qualitative

Consideration of externalities which assigns relative values or rankings to the costs and benefits. This approach allows expert assessments to be derived when actual data from conclusive scientific investigation of impacts are not available.

Quantitative

Consideration of externalities which provides value based on available information on impacts. This approach allows for the quantification of impacts without assigning a monetary value to those impacts (for example, tons of crop loss).

R

Ramping Capability

A measure of the speed at which a generating unit can increase or decrease output.

Rate Base

The value of property upon which a utility is permitted to earn a specified rate of return as established by a regulatory authority. The rate base generally represents the book value of property used by the utility in providing service and may be calculated by any one or a combination of the following accounting methods: fair value, prudent investment, reproduction cost, or original cost. Depending on which method is used, the rate base includes net cost of plant in service, working cash, materials and supplies, and deductions for accumulated provisions for depreciation, contributions in aid of construction, customer advances for construction, accumulated deferred income taxes, and accumulated deferred investment tax credits.

Reactive Power

The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment.

Real Dollars

While a complex topic, at its most basic, value is a measure of money over a period of time. Generally expressed in terms of units of US dollars, real dollars represents the true cost inclusive of inflationary adjustments (such as simple price changes which, of course, are usually price increases). Over time, real dollars are a measure of purchasing power. As such, real dollars can also be referred to as constant dollars.

Recloser

A circuit breaker with the ability to reclose after a fault-induced circuit break.

Reconductoring

The process of replacing the cable or wiring on a distribution or transmission line.

Regulating Reserves

The capacity required to maintain system frequency through fast balancing.

Reliability

The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system, Adequacy of Supply and System Security. See also System Reliability on page B-33.

Renewable Energy Resources

Energy resources that are naturally replenished, but limited in their constant availability (or flow). They are virtually inexhaustible but are limited in the amount of energy that is available over a given period of time. The amount of some renewable resources (such as geothermal and biomass) might be limited over the short term as stocks are depleted by use, but on a time scale of decades or perhaps centuries, they can likely be replenished.

Renewable energy resources include photovoltaics, biomass, hydroelectric, geothermal, solar, and wind. In the future, they could also include the use of ocean thermal, wave, and tidal action technologies. Utility renewable resource applications include bulk electricity generation, on-site electricity generation, distributed electricity generation, non-grid-connected generation, and demand-reduction (energy efficiency) technologies.

Unlike fossil fuel generation plants (which can be sited where most convenient because the fuel is transported to the plant), renewable energy generation plants must be sited where the energy is available; that is, a wind farm must be sited where a sufficient and relatively constant supply of wind is available. In other words, fossil fuels can be brought to their generation plants whereas renewable energy generating plants must be brought to the renewable energy source.

Renewable Portfolio Standard (RPS)

A goal for the percentage of electricity sales in Hawai'i to be derived from renewable energy sources. The RPS is set by state law. Savings from energy efficiency and displacement or offset technologies are part of the RPS until January 2015, when they will instead be counted toward the new EEPS. The current RPS calls for 10% of net electricity sales by December 31, 2010; 15% of net electricity sales by December 31, 2015; 25% of net electricity sales by December 31, 2020; and 40% of net electricity sales by December 31, 2030.

Repowering

A means of permanently increasing the output and/or the efficiency of conventional thermal generating facilities.

Reserve

There are two types of reserves:

> ***Operating Reserve:*** That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. See also Operating Reserves on page B-23.

Planning Reserve: The difference between a control area's expected annual peak capability and its expected annual peak demand expressed as a percentage of the annual peak demand.

Reserve Margin (Planning)

The amount of unused available capability of an electric power system at peak load for a utility system as a percentage of total capability. Such capacity may be maintained for the purpose of providing operational flexibility and for preserving system reliability.

Residential Direct Load Control (RDLC)

A demand response program that offers incentives to customers who allow the Hawaiian Electric Companies to install a load control switch on residential electric water heater, so that the load can be curtailed remotely by the utility during times of system need.

Resiliency

The ability to quickly locate faults and automatically restore service after a fault, using FLISR (Fault Location, Isolation, & Service Restoration).

Retail Rate

The rate at which specific classes of customers compensate the utility for grid electricity.

Reverse Flow

The flow of electricity from the customer site onto the distribution circuit or from the distribution circuit through the substation to higher voltage lines. Also called backfeed.

Rule 14H

The Hawaiian Electric Company rules governing service connections and facilities on a customer's premises.

Rule 18

The Hawaiian Electric Company rules governing Net Energy Metering.

S

Schedule Q

The tariff structure that governs Hawaiian Electric purchases from qualifying facilities 100kW or less

Scheduled Outage

See Outage on page B-23.

Secondary Lines

Low voltage distribution lines directly serving customers.

Service Charge

A fixed customer charge intended to allocate the cost of servicing the grid to all customers, regardless of capacity needs.

Service Level Issue

Any issue arising at the point of service provision to customers, including traditional utility service and grounding transformer overloads caused by DG PV.

Service Transformer

A transformer that performs the final voltage step-down from the distribution circuit to levels usable by customers.

Simple-Cycle Combustion Turbine (SCCT)

A generating unit in which the combustion turbine operates in a stand-alone mode, without waste heat recovery.

Single-Train Combined Cycle (STCC)

See Combined Cycle on page B-5.

Small Business Direct Load Control (SBDLC)

A demand response programs that allows the electric utility to curtail load without intervention of an operator at the end user's (customer's) premises. For example, the utility may install a load control switch on an electric water heater or air-conditioning unit, so that the load can be controlled remotely by the utility during times of system need.

Smart Grid

A platform connecting grid hardware devices to smart grid applications, including VVO, AMI, Direct Load Control, and Electric Vehicle Charging.

Smart Inverter Working Group (SIWG)

A working group created by the California Public Utilities Commission to propose updates to the technical requirements of inverters.

Spinning Reserve Service

See Operating Reserves on page B-23.

Standard Interconnection Agreement (SIA)

Rules governing interconnection of distributed generation systems.

Standby Charge

A fixed charge intended to recover significant backup generation facilities the utility must maintain to ensure grid reliability in the event of widespread DG outages.

Static VAR Compensator

A device used provide reactive power in order to smooth voltage swings.

Steady-State Conditions

Conditions governing normal grid operations; contrasted with transient conditions.

Steam Turbine (ST)

A turbine that is powered by pressurized steam and provides rotary power for an electrical generator.

Storage

A system or a device capable of storing electrical energy to serve as an ancillary service resource on the utility system and/or to provide other energy services. Three major types of energy storage are relevant for consideration in Hawaiʻi:

Battery: An energy storage device composed of one or more electrolyte cells that stores chemical energy. A large-scale battery can provide a number of ancillary services, including frequency regulation, voltage support (dynamic reactive power supply), load following, and black start as well as providing energy services such as peak shaving, valley filling, and potentially energy arbitrage. Also referred to as Battery Energy Storage System (BESS).

Flywheel: A cylinder that spins at very high speeds, storing rotational kinetic energy. A flywheel can be combined with a device that operates either as an electric motor that accelerates the flywheel to store energy or as a generator that produces electricity from the energy stored in the flywheel. The faster the flywheel spins, the more energy it retains. Energy can be drawn off as needed by slowing the flywheel. A large flywheel plant can provide a number of ancillary services including frequency regulation, voltage support (dynamic reactive power supply), and potentially spinning reserve.

Pumped Storage Hydro: Pumped storage hydro facilities typically use off-peak electricity to pump water from a lower reservoir into one at a higher elevation storing potential energy. When the water stored in the upper reservoir is released, it is passed through hydraulic turbines to generate electricity. The off-peak electrical energy used to pump the water uphill can be stored indefinitely as gravitational energy in the upper reservoir. Thus, two reservoirs in combination can be used to store electrical energy for a long period of time, and in large quantities. A modern pumped-storage facility can provide a number of ancillary services, such as frequency regulation, voltage support (dynamic reactive power), spinning and non-spinning reserve, load following and black start as well as energy services such as peak shaving and energy arbitrage.

Sulfur Oxide (SO_x)

A precursor to sulfates and acidic depositions formed when fuel (oil or coal) containing sulfur is combusted. It is a regulated pollutant.

Substation

A small building or fenced in yard containing switches, transformers, and other equipment and structures for the purpose of stepping up or stepping down voltage, switching and monitoring transmission and distribution circuits, and other service functions. As electricity gets closer to where it is to be used, it goes through a substation where the voltage is lowered so it can be used by customers such as homes, schools, and factories.

Substation Transformer

Substation-sited transformers used to change voltage levels between transmission lines, or between transmission lines and distribution lines.

Supervisory Control and Data Acquisition (SCADA)

A system used for monitoring and control of remote equipment using communications networks.

Supplemental Reserve Service

See Operating Reserves on page B-23.

Supply-Side Management

Actions taken to ensure the generation, transmission, and distribution of energy are conducted efficiently. Supply-side generation includes generating plants that supply power into the electric grid.

Switching Station

An electrical substation, with a single voltage level, whose only functions are switching actions.

Synchronous Condensers

Devices used to modulate the voltage or power factor of transmission lines. Synchronous condensers typically provide dynamic reactive power support, and are deployed only where dynamic reactive power support needs to be maintained at a particular location.

System
The utility grid: a combination of generation, transmission, and distribution components.

System Average Interruption Duration Index (SAIDI)
The average outage duration for each customer served. A reliability indicator.

System Average Interruption Frequency Index (SAIFI)
The average number of interruptions that a utility customer would experience. A reliability indicator.

System Reliability
Broadly defined as the ability of the utility system to meet the demand of its customers while maintaining system stability. Reliability can be measured in terms of the number of hours that the system demand is met.

System Security
The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

T

Tariff
A published volume of rate schedules and general terms and conditions under which a product or service will be supplied.

Thermal Loading
The maximum current that a conductor can transfer without overheating.

Time-of-Use (TOU) Rates
The pricing of electricity based on the estimated cost of electricity during a particular time block. Time-of-use rates are usually divided into three or four time blocks per twenty-four hour period (on-peak, mid-peak, off-peak and sometimes super off-peak) and by seasons of the year (summer and winter). Real-time pricing differs from TOU rates in that it is based on actual (as opposed to forecasted) prices which may fluctuate many times a day and are weather-sensitive, rather than varying with a fixed schedule.

Total Resource Cost (TRC)
A method for measuring the net costs of a conservation, load management, or fuel substitution program as a resource option, based on the total costs of the program, including both the participants' and the utility's costs.

Transformer

A device used to change voltage levels to facilitate the transfer of power from the generating plant to the customer. A step-up transformer increases the voltage (power) of electricity while a step-down transformer decreases it.

Transient Condition

An aberrant grid condition that begins with an adverse event and ends with the return to steady-state conditions (stable voltage, connection of all loads).

Transient Over Voltage (TrOV)

A transient issue characterized by a sudden spike in voltage above steady-state conditions on a circuit, or on a subset or component of a circuit.

Transmission and Distribution (T&D)

Transmission lines are used for the bulk transfer of electric power across the power system, typically from generators to load centers. Distribution lines are used for transfer of electric power from the bulk power level to end-users and from distributed generators into the bulk power system. In the Hawaiian Electric Companies, standard transmission voltages are 138,000 volts (Hawaiian Electric system only) and 69,000 volts (Hawaiian Electric, Maui Electric, Hawai'i Electric Light). Distribution voltage is 23,000 volts (Maui Electric) and 13,200 volts (all systems).

Transmission System

The portion of the electric grid the transports bulk energy from generators to the distribution circuits.

Two-Way Communications

The platform and capabilities that are required to allow bi-directional communication between the utility and elements of the grid (including customer-sited advanced inverters), and control over key functions of those elements. The platform must contain monitor and control functions, be TCP/IP addressable, be compliant with IEC 61850, and provide cyber security at the transport and application layers as well as user and device authentication.

U

Ultra Low Sulfur Diesel (ULSD)

A diesel fuel that contains less 15 parts per million of sulfur.

Under Frequency Load Shedding (UFLS)

A system protection scheme used during transient adverse conditions to balance load and generation.

Under Voltage Load Shedding (UVLS)

A system protection scheme used during low voltage conditions to avoid a voltage collapse.

Under Voltage Violation

Bus voltage less than 0.9 per unit.

United States Department of Defense (DOD)

An executive department of the U.S. government responsible for coordinating and supervising all agencies and functions of the Federal government that are concerned directly with national security and the armed forces.

United States Department of Energy (DOE)

An executive department of the U.S. government that is concerned with the United States' policies regarding energy, environmental, and nuclear challenges.

United States Environmental Protection Agency (EPA)

An executive department of the U.S. government whose mission is to protect human health and the environment.

University of Hawaiʻi Economic Research Organization (UHERO)

The economic research organization at the University of Hawaiʻi, which is a source for information about the people, environment, and Hawai`i and the Asia-Pacific economies, including energy issues.

V

Variable Renewable Energy

A generator whose output varies with the availability of it primary energy resource, such as wind, the sun, and flowing water. The primary energy source cannot be controlled in the same manner as firm, conventional, fossil-fuel generators. Specifically, while a variable generator (without storage) can be dispatched down, its output cannot be guaranteed 100% of the time when needed. However, the primary energy source may be stored for future use, such as with solar thermal storage, or when converted into electricity via storage technologies. Also referred to as intermittent and as-available renewable energy.

Voltage

Voltage is a measure of the electromotive force or electric pressure for moving electricity.

Voltage Collapse

The sudden and large decrease in the voltage that precipitates shutdown of the electrical system.

Voltage Regulation

A measure of change in the voltage magnitude between the sending and receiving end of a component, such as a transmission or distribution line.

Voltage Regulator Controller

A device used to monitor and regulate voltage levels.

Volt/VAR control

Control over voltage and reactive power levels.

Volt/VAR Optimization (VVO)

The process of monitoring voltages at customer premises through an AMI system, and optimizing them using reactive power control and voltage control capabilities.

W

Watt

The basic unit of measure of electric power, capacity, or demand. It is a derived unit of power in the International System of Units (SI), named after the Scottish engineer James Watt (1736–1819).

C. Modeling Analyses Methods

Three teams conducted independent modeling analysis for produce the results presented in the PSIP. The teams included Hawaiian Electric Company generation planning, Black & Veatch, and PA Consulting. Each team employed a different modeling analysis method. In additional, Electric Power Systems employed a grid simulation model to conduct its system security studies.

Each of these four modeling methods are presented.

GRID SIMULATION MODEL FOR SYSTEM SECURITY ANALYSIS

The Transmission Planning Division of Hawaiian Electric Company 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 after which most 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.

HAWAIIAN ELECTRIC: P-MONTH MODELING ANALYSIS METHODS

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.

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.

PMONTH has a Monte Carlo Simulation option in which random draws are used to create multiple scenarios (iterations) to model the effect of random forced outages of generating units. Each scenario is simulated individually; the averages of the results for all the scenarios represent the expected system results. This Option provides the most accurate simulation of the power system operations if sufficient number of scenarios are used. However, the computer run time can be long if many scenarios are run. The number of scenarios 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 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 roundtrip 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 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 the 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:

1. Energy and hourly load to be served by firm and non-firm generating units
2. Load carrying capability of each firm generating unit
3. Efficiency characteristics of each firm generating unit
4. Variable O&M costs
5. Operating constraints such as must-run units or minimum energy purchases from purchased power producers
6. Overhaul maintenance schedules for the generating units
7. Estimated forced outage rates and maintenance outage rates
8. Regulating reserve requirements
9. Demand response and energy storage resources
10. 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:

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

Post-Processing

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

1. Capital costs for new generating units, renewable and energy storage resources, allocated based on capital expenditure profiles
2. Capital costs for utility projects such as fuel conversions or the retirement of existing utility generating units
3. Payments to Independent Power Producers (IPP) for purchased power, including Feed in Tariff projects
4. 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:

1. Differential accumulated present value of annual revenue requirements
2. Differential rate impact
3. Monthly bill impact
4. Total system curtailment
5. Renewable Portfolio Standards (RPS)
6. Gas consumption
7. Utility CO_2 emissions
8. Annual Generation Mix
9. 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 Renewable Portfolio Standards (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.

PA CONSULTING: PRODUCTION COST MODELING

PA Consulting Group (PA) performed hourly and sub-hourly production cost modeling to support the Hawaiian Electric Companies' development of the PSIPs. The production cost modeling was conducted using the EPIS AURORAxmp software. AURORA is an hourly chronological dispatch model used to model electricity markets. The model has broad capabilities. The primary forecasting capabilities that we used in the model are least cost dispatch and long-term capacity expansion modeling.

The capacity expansion model is an optimization model that determines the most cost effective long-term generation expansion and retirement schedules, based upon assumptions regarding capital costs, operating costs, and operational constraints, as well as system constraints such as reserve margins and spin requirements. The most cost effective plan is based upon the solution with the lowest net present value.

The chronological dispatch model determines the least-cost solution for dispatching resources, including demand side resources, to meet load and reserve margin requirements. The dispatch solution honors individual generator constraints and factors in marginal dispatch costs, including fuel and O&M. Each resource is modeled individually, taking into account the unit-specific cost and operating characteristics. Units are dispatched in the simulation in the order of economic merit (according to dispatch cost) until adequate generation is brought on line to meet the load. The model factors in out-of-merit dispatch due to must-run and must-take requirements. The model also curtails resources if the constrained generation exceeds demand.

The sub-hourly modeling was structured to address the Commission's interest in utilizing sub-hourly modeling to more fully investigate issues raised in the April 28th D&Os. These issues include evaluation of the value of DR and DG in the context of the Company's vision for the future of the utility, and consideration of resources required to support the integration of more intermittent renewable generation resources, and to reduce curtailments where it is economic to do so.

Specifically, PA used the sub-hourly modeling to identify any periods with unserved energy or periods with significant potential for renewable energy curtailment. We evaluated whether changing the resource mix can cost effectively address these issues. This assessment was conducted using iterative analyses to identify whether changing the available resource mix will reduce curtailment or dispatch costs.

AURORA was used to both evaluate a least-cost capacity expansion and retirement plan, and also to model scenarios of alternative resource plans in order to identify the incremental costs associated with alternative policies.

Key Inputs

PA worked with Hawaiian Electric Resource Planning and Black & Veatch to develop a common set of assumptions for the modeling initiative. These assumptions include:

- Resource characteristics (such as capacity, heat rates, ramp rates, minimum-up times, and minimum-down times)
- Characteristics of demand response programs
- Fuel costs
- Types of fuel that each fossil generator will use
- Identification of timing and generators that would be converted to burn LNG
- Fixed and variable operating costs
- Capital costs necessary to extend the life of existing generation
- Costs for new generation technologies (capital and operating)
- Availability of new generation resources (timing and capacities)
- System load forecasts
- Production profiles for variable energy resources.

Hourly Production Cost Modeling

Generation and demand side resources are dispatched to serve the system load. The base case simulations reflect the current configuration in which each island is a stand-alone system.[1] Units with low operating costs relative to other facilities are dispatched often; units with high costs are dispatched less frequently. The hourly dispatch logic is based upon short-run marginal generation costs, which include: fuel costs, variable operating costs, start-up costs, and emission costs. In contrast, the long-term retirement and expansion plan considers all costs rather than just marginal costs. The additional costs in the long run optimization include fixed O&M costs and capital costs.

The hour-by-hour interaction of supply and demand determines how frequently plants are dispatched within a market. The model incorporates logic for a variety of constraints that are incorporated into the least-cost dispatch logic. These constraints include: must-run requirements, minimum load requirements, ramp times, minimum uptimes, and minimum downtimes. The model also includes planned maintenance schedules and forced outage rates. The determination of the least-cost dispatch, subject to constraints, is based upon the model, assuming perfect information about future hourly loads.

PA used an iterative process to develop the preferred PSIP for each island. Our first step was to represent the existing systems within the model and develop simulations for the

[1] A case was run with a 200 MW DC transmission cable connecting the islands of Oʻahu and Maui.

first two years. We used these simulations to calibrate the models to reasonably represent how the current power systems dispatch and to capture the current generation operating costs, fuel costs, and purchase power agreements. We then used the optimization model to develop a least cost base case that factored in constraints related to committed generation retirements, assumptions about future levels of distributed generation, and availability of new generation resources. In the third stage of our analysis we tested alternative scenarios to examine the incremental costs of alternative power supply plans. The analysis in the third stage was based upon modeling specific scenarios over the 2015–2030 time horizon and did not use the long-term resource optimization feature.

Sub-Hourly Production Cost Modeling

The purpose of the sub-hourly modeling was to gain insights regarding ramp constraints, identify potential issues with large amounts of variable supply resources, and identify the potential value of fast response resources, including demand response resources. We use sub-hourly modeling to identify any periods with unserved energy or high frequency, and amounts of renewable energy curtailment. We then assess whether changing the resource mix can cost effectively address these issues.

The sub-hourly modeling was conducted with the previously described production cost model. In order to develop the sub-hourly analysis, it was necessary to convert all the hourly generation and variable supply resource profiles into five-minute profiles. We did not change any assumptions about fuel costs or generator constraints. A brief description of the process for developing the five-minute profiles follows.

We started with available one-minute historic net load profiles, wind production profiles, and solar production profiles. We developed a one-minute gross load profile from the one-minute profiles into five-minute profiles using averages of the five-minute periods. In instances where we did not have sub-hourly data, such as for hydro generation, we assumed that the generation was constant over the one hour period.

PA modeled four days per month at the five-minute level, rather than every day, due to the large amounts of data associated with five-minute modeling. The four representative days included a mid-week weekday (Monday–Thursday), a Friday, and each week-end day.

An overview of PA's sub-hourly modeling methodology follows. This modeling will be conducted at the five-minute intervals.

1. Development of Sub-Hour Modeling Assumptions and Data Inputs

We based inputs to the sub-hourly model on the assumptions agreed upon for the hourly model (fuel costs, generator characteristics, and load forecast) and on one-minute data.

The one-minute data include historic net load profiles, wind production profiles, and solar production profiles. In addition, PA incorporated input from parallel tasks related to development of DG and DR unit characteristics and cost options, as well as how that analysis should be integrated into the sub-hourly chronological dispatch modeling. PA closely coordinated these efforts with the company to ensure that the modeling assumptions and scenarios modeled are consistent with the Company's strategic vision.

2. Translation of Hourly Model Assumptions/Inputs to Five-minute Data

The vast majority of assumptions and inputs used for hourly modeling were used directly in the 5-minute modeling. These include fuel costs, resource capacities and efficiencies, and resource variable operating costs, as well as system operating reserve requirements. In some cases, dynamic information such as resource ramp rates and other time dependent assumptions were adjusted to correspond to the five-minute modeling interval, so that the inputs were correctly incorporated in to the model's economic dispatch algorithms.

3. Development of Five-minute Profiles for Modeling Inputs

We converted renewable generation production profiles from one-minute to five-minute data, and converted the hourly load forecasts to five-minute profiles using the historic one minute load profiles. The conversion ensured consistency between the hourly, one-minute, and five-minute data sets.

Renewable Generation Profiles. Five-minute profiles for wind and solar were constructed from available one-minute data. PA analyzed the one-minute data to develop representative five-minute shapes for typical days in each month. The representative five-minute shapes were not limited to simple averages of one-minute renewable output levels across days, but were structured to represent the extent of variation that exists at the one minute level. There was only one one-minute wind and solar profile per island so all solar and wind resources on each island used the common wind / solar profile. The capacity of the individual units were adjusted so that over a year the total production matched each unit's characteristics.

Load Shape and Distributed Generation Profiles. The derivation of the five-minute load shape profiles required a different analysis, since existing load data reflect behind-the-meter generation. Given time limitations, PA utilize an Excel-based model to construct five-minute load shapes for future years. Future load shapes were based on the current five-minute system load shape and the hourly load forecasts. PA used the five-minute PV production shape and penetration estimates for behind-the-meter solar to allocate the hourly loads into five-minute blocks representing gross system loads (without behind-the-meter generation) and net system loads for future years.

4. Sub-Hourly Model Development and Calibration

PA modeled four days per month at the five-minute level. We did not model all days due to the large amount of data at the five-minute level, and array limitations in the AURORAxmp software. The four representative days included a mid-week weekday (Monday–Thursday), a Friday, and each week-end day. Depending on model run-times and post processing efforts, PA either weighted the midweek day to represent four days, or performed additional simulations to capture a typical week per month to facilitate developing aggregate annual results.

PA developed and validated sub-hourly generation dispatch models for the Maui, Oʻahu, and Hawaiʻi Island systems. Since AURORAxmp is currently configured for hourly modeling, PA had to adjust input parameters to facilitate five-minute modeling. PA adjusted input parameters so that each standard Aurora model hour is interpreted as a five-minute period. Hence, each representative day consisted of 288 standard Aurora model hours. Each representative day was modeled independently, and the standard Aurora model hourly output was aggregated through post processing to produce results for the day.

PA conducted a calibration exercise to verify that the model results made sense in the context of the sub-hourly modeling. We also verified that the sub-hourly modeling results are logical and reasonable, based upon PA's expertise and based upon consultation with generation planning and generation operations staff expertise within the Company. After the results were validated for each system, PA executed simulations of the representative, P5, and P95 cases for each system. Annual system costs and performance metrics were calculated for each set of system conditions.

The simulations provided insights into the resource requirements necessary to meet load requirements with a mix of intermittent and non-intermittent resources. PA used the hourly simulations to capture the full capital and fixed operating costs for the purposes of estimating the total generation system operating costs at the annual level.

BLACK & VEATCH: ADAPTIVE PLANNING MODEL

Black & Veatch is applying its Adaptive Planning Framework to support the PSIP. Adaptive planning provides a framework for modeling complex systems, exploring options (and impacts of constraints), and comparing such options across varying metrics. Key metrics or outcomes would be costs, annual capital commitment required, degree of renewable penetration (capacity, energy served), and system reliability.

The Adaptive Planning Framework manages the overall calculation and cost accounting process. PSIP-specific requirements will be directly addressed by configuring the model:

- Dispatch methodology defined by collective Hawaiian Electric team, based on legal mandates, operational protocols, and defined reserve margins.
- Dispatch models and algorithms tailored to address system constraints (safety, security), loading or ramping criteria defined by Hawaiian Electric by asset class, battery charge, and discharge protocols by size and class of battery, among others.
- Repair times by asset class for projected failures and scheduled outages.
- Full cost accounting of all power supply elements by asset class, nature of cost, and other factors.

Different solution approaches can be applied in adaptive planning. As configured for this plan, the dispatch and economic models do not optimize capacity additions directly, as we believe that there are number of factors and complexities that dictate technology strategies and paths that need to be "engineered". We have, rather, focused on leveraging the model to evaluate alternate technology and capacity plans, including the adequacy of these plans to meet reserve margin or cause curtailment.

For this particular problem, given the complexity, the number of constraints, and the need to consider system security and reliability thresholds in each period, we have elected to apply the following:

- In concert with Hawaiian Electric and PA Consulting, define the general characteristics of base "path" based on central strategy and glide-path analysis. This will define some key initial assumptions regarding technology choice, timing, and retirements.
- Based on this analysis, the B&V team will then define alternative technology mixes or paths that need to be investigated; the focus would be to improve economics, flexibility, grid resiliency, or other factors based on our assessment of year-to-year unit commitment and dispatch data; this effort will also directly explore roles and penetration of battery assets over time.

- The team will generate sensitivities for each path (base and alternative) to stress test results; key variables that can be considered would be aggregate demand by system, the amount of spinning reserves over time (by year coincident with asset mix and by hour to address night-time or off-peak versus peak requirements), timing of capital investments, technology flips (battery versus pumped storage, battery versus thermal for contingency, etc.), timing of retirements, etc.

We believe that this approach maximizes our ability to provide visibility into results and key assumptions, as needed to define optimal PSIP path. It will also allow for direct comparison of decisions and timing that will be critical for Hawaiian Electric in subsequent steps to refine financial engineering of overall rates. Given the short time frame of this study, we do not plan on directly integrating a regulatory or rate model with AP framework, but would work with Hawaiian Electric to apply results of our work within existing spreadsheet models to enable analysis of investment requirements and the nature of investments over the evaluation period.

Economic results will be driven, in part, by market forecasts for fuel (oil, LNG, etc.). The Black & Veatch framework provides robust scenario analysis that will be applied in this case to evaluate:

- Mix and timing of renewable and energy storage assets
- Timing of retirements
- Timing and nature of new generation additions
- Timing and nature of participation from IPPs
- System characteristics
- Reliability risk based on level of investment and intensity of asset type
- Alternate views of costs including market price of fuel, the cost of implementing technology, etc., as needed to address increasingly higher degree of renewable penetration over time.

Economics can be applied in different forms within the model. We can consider:

- Direct capital investment in year of investments driven by project S-curves.
- Levelized costs based on spread of CAPEX and other related costs into an equivalent annual annuity.
- RRF schedule. Capital can be spread and factors can be assigned based on RRF input schedules.
- Third-party contract (IPP, DR, etc.) where the energy or service can be contracted on $/MWh, $/MW, or combination.

Model outputs will be populated within spreadsheets and data viewers to enable direct analysis and comparison (between cases) of:

- Period values by asset; periods can be either 1-hour or 5-minute for PSIP. We will also consider a smaller segment of 1-minute data to test impacts on wind and solar dispatch and spin. Detailed results would include dispatch MW, costs (capital, VOM, FOM), contribution to renewable, and role (contingency, regulation, energy, etc.)
- Aggregated results by asset; basically the same output as available for the period would be available for the asset by year and overall.
- Typical "daily" or 24-hour view; this view would analyze data for each asset by hour in day resulting from dispatch by asset by year. This will allow us to validate the overall dispatch approach, as well as better characterize roles of units. Values calculated would include average, min, max, and standard deviation. This will provide insights into rationale for IPP energy supply schedules for assets that are not anticipated to be owned by Hawaiian Electric.

Time Slice Model within Adaptive Planning Framework.

At the heart of the Adaptive Planning framework is a direct solution mathematical framework that enables direct analysis and "integration" of asset performance and aggregate match of resources to demand (as depicted in the figure below) contribution by asset, aggregate reliability, and costs.

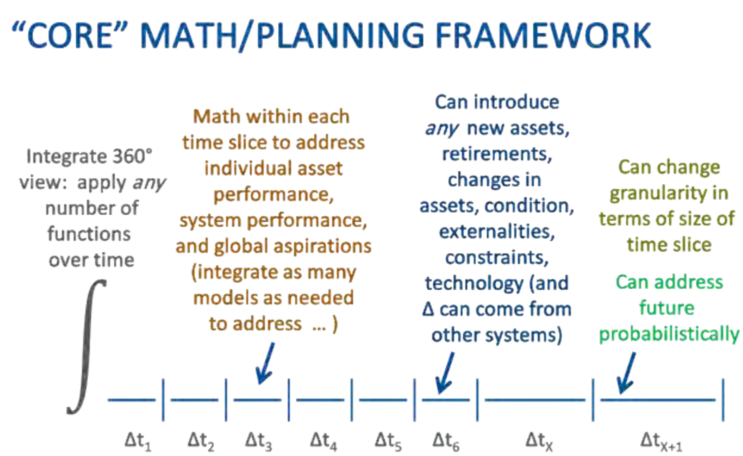

Figure C-1. Black & Veatch Mathematical Modeling Framework

Within the framework, each time slice affords the opportunity for us to:

- Introduce new assets, retire assets, change characteristics (simulate planned outages, etc.).
- Commit assets based on availability, renewable and non-renewable, and economics.

- Incorporate assumptions for wind and solar variability for that particular time slice based on perturbations of the historical wind and solar patterns.
- Incorporate rules for utilizing DG as must-take resource versus curtailable resource.
- Dispatch assets based on protocol and security, and economics including use of DR and energy storage to address ramping or smoothing, forced outages of committed assets, etc.
- Identify boundary conditions (from time slice to time slice) that serve as the basis for evaluating the next time slice; there are a number of instances where actions (such as a start of a 10-minute or 30-minute reserve resource within a particular time slice) will require forward commitment across time slices.

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

- Status (available, scheduled outage, forced outage, retired, etc.)
- Operating efficiency
- Fuel characteristics (if applicable)
- Consumable unit costs
- Revenue requirements for capital expenditure

Each time slice also considers demand, adjusted for DR load shaping programs and, as applicable, DG PV. With this information, the time slice model determines:

- Status applicable to next time slice
- Consumable requirements
- Operating costs

The information generated is available at the time-slice or less granular resolution, for example, hourly, monthly, or annually. In addition, the asset hierarchy allows data to be viewed for each power source or aggregated across sources. Capital costs and other outputs associated with those investments would be tabulated by calendar year or other time domain, as required.

Generation Dispatch Methodology

The dispatch model will be used to set the electrical generation outputs to satisfy the electrical demand at the lowest cost while also satisfying system constraints (constrained optimization). These constraints will include system stability (must-run units), minimum downtime and uptime constraints, spinning and non-spinning reserve margin requirements, and non-dispatchable renewable generation. The model will use the following data:

- Variable costs and start-up costs for electrical generation assets
- Ramp rates, minimum downtime, and minimum uptime for electrical generation assets
- Historical reliability and maintainability (MTBF, MTTR) data for all generation assets
- Solar and wind penetration forecast (by time step resolution)
- Solar and wind forecasts (by time step resolution)
- Demand forecasts (by time step resolution)
- System losses

Demand response will be factored into this model via two forms: 1) change in overall "demand" curve as influenced by time-of-day pricing and 2) modeling of specific DR programs.

Energy storage is applied as a resource to supply capacity, regulation, contingency, and other ancillary services associated with frequency response and security. Energy storage added to supply capacity, regulation, or contingency will be modeled via the dispatch model; energy storage added to frequency response will be considered as a cost component of the overall system.

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 assets may have over another set of assets, 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, etc.)

Similar to an hourly modeling approach, the sub-hourly model will calculate both commitment (what units are generating power) and dispatch (MW contribution of each asset to the target load) 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 hourly model assumes dispatch and commitment set points that do not violate any constraints when the time step is one hour, but when the truer transient nature is exposed at the sub-hourly time step, some otherwise masked constraints will likely become controlling.

The sub-hourly model (5 minute time step) will perform a constrained optimization for both asset commitment and asset dispatch against a sub-hourly desired load that utilizes both near term (next few time steps ahead) and intermediate term (out to the largest minimum down time of committed assets) load forecasts. The assets 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. Each asset will also have a series of constraints or attributes:

- Maximum output (or curtailment)
- Minimum output (or curtailment)
- Ramp up constraint
- Ramp down constraint
- Minimum run time
- Minimum down time
- Maximum run time curve as a function of operating state (energy storage, demand response, emission limits, fuel availability, etc.)
- Time between failures
- Time to restore
- Planned outages
- Startup cost
- Variable cost curve as a function of MW (input/output curve, heat rate curve, O&M, fuel forecast)
- Fixed costs (for annual cost calculations)

There are also system constraints that must be met. These include:

- Spinning reserve requirements (incorporating energy storage and demand response options)
- Grid stability requirements, including must-run units (constraints will be rules-based, as power flow modeling is not envisioned as feasible within the project time constraints)
- 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). We envision sensitivities where selected constraints are relaxed and where the load forecast is modified. This will help test the robustness of the plan.

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 and base constraints. These constraints can be modified to evaluate other policy considerations (such as greater renewable penetration) that may move the solution away from optimal.

D. System Security Standards

The Hawaiian Electric Company contracted with Electric Power Systems and its two senior project engineers, David A Meyer and David W Burlingame, to conduct a system security and stability study and analysis of the Hawai'i Electric Light power grid.

Herewith is a discussion of the study and its resultant effects for system security on the Hawai'i Electric Light power grid.

This study identifies the security requirements for various generation and load scenarios under study for the Hawai'i Electric Light system. As such, the cases were intended to establish the boundary conditions for the security cases. For instance, if thermal units were utilized, the energy storage was sized to withstand the loss of the largest thermal unit at high generation levels, even though in actual practice, the thermal units may be operating at reduced levels to avoid curtailment of renewables.

Contents

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METHODOLOGY

The methodology used to help determine the security requirements was based on simulating system disturbances, including unit trips and line faults, using four periods throughout the day/night. The load values for the periods came for the forecast data provided by Hawai'i Electric Light. The "Min" period case represents the minimum load found throughout the study year. The "Max" period was represents the maximum load found throughout the study year. The "Min Day" and "Max Day" loads represent the minimum and maximum loads found between the hours of 10 AM and 4 PM.

Each of the four basic period cases included high wind and low wind generation in order to determine the wind related boundary conditions for a total of eight cases. Additional cases were created to help determine the generation commitment related to boundary conditions where practical. For instance, cases may compare the use of two and three thermal units online with different levels of the size of an energy storage system (ESS) size in order to evaluate the contingency reserve requirements.

The key performance criterion used to assess the simulation results was the allowance of no more than one stage of under frequency load shedding (UFLS). Acceptable simulation results must also be stable and exhibit satisfactory voltage conditions.

For each case, the amount of contingency reserves for the system was evaluated. Each case had a total contingency reserve value meeting or exceeding the value of the largest unit contingency. If the sum of the spinning reserves and amount of net load found in Stage 1 of the UFLS scheme did not exceed the size of the largest unit contingency, then an ESS was added and sized to meet the largest unit contingency. For instance, comparing two and three thermal unit cases, the two unit case would have a larger sized ESS compared to the three unit case. The ESS size was increased if necessary to meet the performance criteria.

Note that the required size of ESS was typically determined directly from the simulation results. For some cases, the required value was estimated. The estimates were based on the simulation results and the case configurations. The amount of initial estimated ESS size along with the generation unit outputs, amount of spinning reserves, and renewable curtailment were used to assess the required size.

The simulated system disturbances included unit trips and line faults/outages. The unit trips selected included the larger conventional generation units and centralized wind plants. The variable generation and smaller PGV aggregate units were not included. The line faults included a number of higher sensitivity fault locations based on past studies and preliminary results. Zone 1 fault clearing times were used in addition to longer times. Since some Zone 2 fault locations are known to be beyond the critical clearing times of the system, a cursory assessment of the critical clearing times was made.

Generation Scenarios

The following describes the four generation scenarios used for the study. The cost related aspects of each scenario are not listed and do not effect the security studies.

Scenario 1: No New Additions Reference Case

- No generation additions beyond Hu Honua and DG growth in the study period.
- Includes LNG conversion.

Scenario 2: No New Additions Reference Case

- No generation additions beyond Hu Honua and DG growth in the study period
- Assume new unit will be situated at the same location as Keahole
- New geothermal online date is 2020
- For system stability purposes, this West Hawaii geothermal unit will be designated must-run. Keahole will be allowed to cycle as needed
- Unit will be dispatchable in the 7 to 25 MW range and can supply all system constraints

Scenario 3: High Variable Renewable

- Add 40 MW of wind at Lalamilo
- Assume new unit will provide regulating reserves and ramp control by using advanced inverter capabilities, which will reduce the capacity factor; but will still be very high based on the excellent wind resource
- Online date is 2020

Scenario 4: High Variable Renewable without Ancillary Services

- Add 40 MW of wind at Lalamilo
- Assume new unit will not provide its own regulating reserves and ramp control
- Online date is 2020

Major Study Assumptions

The following describes the major assumptions made for the study.

Performance Criteria:

- Do not exceed Stage 1 UFLS
- System must remain stable
- Satisfactory voltage conditions

UFLS Settings:

- Described in reference file "Hawai'i Electric Light PSIP Assumptions-R1.xlsx"
- Stage 1 58.8 Hz
- Stage 2 58.5 Hz
- Stage 3 58.0 Hz
- Stage 4 57.7 Hz
- Kicker block not modeled (20 second delay at 59.3 Hz)

General Generation Commitment Priority:

- PGV: Must Take (27 MW off-peak, 30 MW on-peak)
- Ho Hunoa: Must Run (10–21.5 MW)
- Keahole Single-Train: Must Run (10–24.5 MW, cycled in some cases)
- Keahole Dual-Train: Cycling (17–53.5 MW)
- HEP Single-Train: Cycling (10–28 MW)
- HEP Dual-Train: Cycling (19.5–58 MW)
- Hill 6: Cycling (8–20 MW)
- Puna CT3: Cycling (8–19 MW)

New Lalamilo Wind:

- 40 MW capacity, 20 MW largest contingency
- 75% Regulating Capacity (self-regulating operations)

Variable Generation Levels:

- Outputs vary to help create boundary conditions for conventional unit outputs

Curtailment:

- New distributed PV was curtailed as necessary. In some minimum cases without PV for Scenarios 3&4, the new Lalamilo was curtailed.

Ramp Rates:

- The addition of an ESS will provide the additional ramping capacity required to meet the ramp rate requirements.

PV Capacities:

- Maximum 85% of total capacity used energy output
- Legacy PV 10 MW (8.5 MW output)
- All other PV, extended ride-through settings

Renewable Contingencies:

- The largest single contingency of wind and PV generation does not exceed the same level of contingency as the largest unit.

Legacy (IEEE 1547) Distributed PV Settings:

Element		Stage 1 Setpoint (Hz, pu)	Stage 1 Time (Sec.)	Stage 2 Setpoint (Hz, pu)	Stage 2 Time (Sec.)
Frequency (Hz)	Under	59.3	0.17	N/A	N/A
	Over	60.5	0.17	N/A	N/A
Voltage (pu)	Under	0.88	2.0	0.5	0.17
	Over	1.1	1.0	1.2	0.17

Table D-1. Legacy/IEEE 1547 Distributed PV Settings

Rule 14H Distributed PV Settings (progressive changes highlighted in blue):

Element		Stage 1 Setpoint (Hz, pu)	Stage 1 Time (Sec.)	Stage 2 Setpoint (Hz, pu)	Stage 2 Time (Sec.)
Frequency (Hz)	Under	57.0	0.17	N/A	N/A
	Over	60.5	0.17	N/A	N/A
Voltage (pu)	Under	0.88	2.0	0.5	0.17
	Over	1.1	1.0	1.2	0.17

Table D-2. Rule 14H Distributed PV Settings

Extended Distributed PV Settings (progressive changes highlighted in blue):

Element		Stage 1 Setpoint (Hz, pu)	Stage 1 Time (Sec.)	Stage 2 Setpoint (Hz, pu)	Stage 2 Time (Sec.)
Frequency (Hz)	Under	57.0	20.0	N/A	N/A
	Over	63.0	20.0	N/A	N/A
Voltage (pu)	Under	0.88	2.0	0.5	0.5
	Over	1.1	1.0	1.2	0.17

Table D-3. Rule Extended Distributed PV Settings

HAWAI'I ELECTRIC LIGHT INTERMEDIATE CASES

Case Descriptions

The intermediate cases chosen for analysis consist of two different study years. The year 2019 was chosen for use with Scenario 1. This is a potential transition year prior to the year 2020 when the new generation in the other three scenarios is added to the system. In 2019, the four load period values are very similar to the 2030 values. The largest difference is 4 MW in the Min Day period. The amount of distributed PV found in 2019 78 MW (85% of capacity). This amount is 19 MW less than 2030, but is does include roughly 2/3 of the PV growth between 2014 and 2030.

The 2025 year for the other three new generation scenarios was chosen primarily due to its high loading and distributed PV levels. The high load levels are found in all four load periods. The distributed PV level is approximately 8 MW less than the 2030 levels at 89 MW. The table below describes the loads for each time period and the PV levels. The initial wind capacity consists of the existing wind capacity. Scenarios 3 and 4 add 40 MW additional wind.

The load and renewable generation capacities are summarized in the following table for the year 2019 and 2025.

	Study Year	
Time Periods	2019	2025
Min	88	91
Min Day	148	153
Max Day	183	188
Max	193	199
PV Capacity	91	105
85% PV Capacity	78	89
Initial Wind Capacity	31	31

Table D-4. Intermediate Case Load Levels (MW)

Generation Dispatches

The dispatches for all generation scenarios and time periods are provided in the following tables. The total amount of generation and initial estimated ESS size is included along with each individual unit output. Note that the Scenario 3 and Scenario 4 dispatches and results overlap due to the identical cases produced without wind. Scenario 3 includes only the wind cases and also includes additional regulation provided by the Lalamilo wind generation.

	Min - 88 MW			Min Day - 148 MW			Max Day - 183 MW		Max - 193 MW		
	High Wind		Low Wind	High Wind		Low Wind	High Wind	Low Wind	High Wind		Low Wind
Generation	3 Units	2 Units	3 Units	3 Units	2 Units	3 Units	3 Units	4 Units	7 Units	6 Units	7 Units
Keahole CT-4	15.0		18.0	17.5		17.3	18.0	19.0	18.5	19.0	19.0
Keahole CT-5								19.0	18.5	19.0	19.0
Keahole ST-7	3.8		4.5	4.4		4.3	4.5	13.3	13.0	13.3	13.3
Keahole 1CTCC	18.8		22.5	21.9		21.6	22.5				
Keahole 2CTCC								51.3	50.0	51.3	51.3
PGV Total	27.0	32.0	32.3	30.0	30.0	29.0	30.0	30.0	30.0	32.0	37.0
Hu Honua	15.0	18.5	20.5	20.5	18.5	20.5	20.5	20.5	20.5	20.5	20.5
Hill Unit No. 6									13.0		19.5
HEP CT1									19.0	19.5	19.5
HEP CT2									19.0	19.5	19.5
HEP ST									16.8	17.3	17.3
HEP 1 UNIT CC											
HEP 2 UNITS CC									54.8	56.3	56.3
As-availables	2.9	15.6	16.2	1.8	3.0	1.2	8.8	5.5	2.2	10.5	15.5
HRD	10.5	10.5	-	10.5	10.5	-	10.5	-	10.5	10.5	-
Apollo	20.5	20.5	-	20.5	20.5	-	20.5	-	20.5	20.5	-
Distributed PV	-	-	-	50.0	74.0	78.0	78.0	78.0	-	-	-
Total Generation	94.7	97.1	91.5	155.2	156.5	150.3	190.8	185.3	201.5	201.6	200.1
ESS for Cont. Res.	-	7.0	10.0	9.0	6.0	9.0	9.0	11.0	-	2.0	3.0

Table D-5. 2019 Scenario 1 Dispatch (MW)

	Min - 91 MW				Min Day - 153 MW				Max Day - 188 MW				Max - 199 MW			
	High Wind		Low Wind		High Wind		Low Wind		High Wind		Low Wind		High Wind		Low Wind	
Generation	3 Units	2 Units	4 Units	3 Units	3 Units	2 Units	3 Units	2 Units	4 Units	3 Units	5 Units	4 Units	7 Units	6 Units	8 Units	7 Units
Keahole CT-4			16.0						18.0		18.0	19.0	18.0	19.5	19.0	19.5
Keahole CT-5											17.3		17.0	19.0	19.0	19.5
Keahole ST-7			4.0						4.5		12.4	4.8	12.3	13.5	13.3	13.7
Keahole 1CTCC			20.0						22.5			23.8				
Keahole 2CTCC											47.7		47.3	52.0	51.3	52.7
PGV Total	30.0	31.0	27.0	35.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	37.0	30.0	38.0
Hu Honua	11.0		20.5	20.5	20.5		20.5		20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Hill Unit No. 6															19.5	
HEP CT1													18.0	19.0	19.5	19.5
HEP CT2													18.0		19.5	19.5
HEP ST													15.9	8.4	17.3	17.3
HEP 1 UNIT CC														27.4		
HEP 2 UNITS CC													51.9		56.3	56.3
As-availables	2.7	12.6	2.2	15.1	2.9	2.8	3.0	13.0	2.5	2.2	4.1	3.0	2.5	13.9	3.0	12.3
New Geothermal	23.0	23.0	23.0	24.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	24.0	23.0	24.0	23.0	24.0
HRD	10.5	10.5			10.5	10.5			10.5	10.5			10.5	10.5		
Apollo	20.5	20.5			20.5	20.5			20.5	20.5			20.5	20.5		
Distributed PV					53.0	73.0	79.0	89.0	65.0	89.0	65.0	89.0				
Total Generation	97.7	97.6	92.7	94.6	160.4	159.8	155.5	155.0	194.5	195.7	190.3	190.3	206.2	205.8	203.6	203.7
ESS for Cont. Res.	-	11.0	5.0	11.0	14.0	15.0	14.0	15.0	8.0	10.0	6.0	11.0	-	2.0	-	5.0

Table D-6. 2025 Scenario 2 Dispatch (MW)

Generation	Min - 91 MW High Wind 2 Units	Min Day - 153 MW High Wind 2 Units	Max Day - 188 MW High Wind 2 Units	Max - 199 MW High Wind 6 Units
Keahole CT-4	-	-	-	19.0
Keahole CT-5	-	-	-	19.0
Keahole ST-7				13.3
Keahole 1CTCC				
Keahole 2CTCC				51.3
PGV Total	29.0	30.0	30.0	30.0
Hu Honua	20.5	20.5	20.5	20.5
Hill Unit No. 6	-	-	-	-
HEP CT1	-	-	-	19.0
HEP CT2	-	-	-	16.0
HEP ST				15.5
HEP 1 UNIT CC				
HEP 2 UNITS CC				50.5
As-availables	3.5	3.9	6.7	3.7
HRD	10.5	10.5	10.5	10.5
Apollo	20.5	20.5	20.5	20.5
New Wind 1/Lalamino	7.5	10.0	10.0	10.0
New Wind 2/Lalamino	7.5	10.0	10.0	10.0
Distributed PV	-	56.0	89.0	-
Total Generation	99.0	161.4	197.2	207.0
ESS for Cont. Res.	8.0	13.0	9.0	-
Lalamino Wind Reg.	12.0	10.0	10.0	10.0

Table D-7. 2025 Scenario 3 Dispatch (MW)

	Min - 91 MW			Min Day - 153 MW		Max Day - 188 MW		Max - 199 MW	
	High Wind	Low Wind		High Wind	Low Wind	High Wind	Low Wind	High Wind	Low Wind
Generation	2 Units	4 Units	3 Units	2 Units	3 Units	2 Units	4 Units	5 Units	8 Units
Keahole CT-4	-	18.0	19.0	-	18.0	-	18.0	19.0	19.0
Keahole CT-5	-	11.0	-	-	-	-	17.0	19.0	19.0
Keahole ST-7		10.2	4.8		4.5		12.3	13.3	13.3
Keahole 1CTCC			23.8		22.5				
Keahole 2CTCC		39.2					47.3	51.3	51.3
PGV Total	29.0	30.0	35.0	30.0	30.0	30.0	30.0	32.0	35.0
Hu Honua	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Hill Unit No. 6	-	-	-	-	-	-	-	-	19.5
HEP CT1	-	-	-	-	-	-	-	19.0	19.5
HEP CT2	-	-	-	-	-	-	-	-	19.5
HEP ST								8.4	17.3
HEP 1 UNIT CC								27.4	
HEP 2 UNITS CC									56.3
Puna CT-3	-	-	-	-	-	-	-	-	18.0
As-availables	3.5	3.3	15.4	4.3	3.6	5.7	3.5	4.1	6.2
HRD	10.5	-	-	10.5	-	10.5	-	10.5	-
Apollo	20.5	-	-	20.5	-	20.5	-	20.5	-
New Wind 1/Lalamino	7.5	-	-	20.0	-	20.0	-	20.0	-
New Wind 2/Lalamino	7.5	-	-	20.0	-	20.0	-	20.0	-
Distributed PV	-	-	-	36.0	79.0	70.0	89.0	-	-
Total Generation	99.0	93.0	94.7	161.8	155.6	197.2	190.3	206.3	206.8
ESS for Cont. Res.	-	-	11.0	13.0	14.0	9.0	8.0	-	-

Table D-8. 2025 Scenario 4 Dispatch (MW)

Results

The results are summarized in the security constraints tables below. Definitions and notes for the table categories are also provided. The results indicate that an ESS sized in the range of 20–25 MW will cover all unit trips for all four of the generation scenarios. This range correlates with the largest unit contingencies. Note that the increments in ESS size were 5 MW. Thus the maximum required size may be slightly smaller and the differences between differing unit commitments may not be as evident (<5 MW).

The critical clearing time is roughly 11 cycles for all generation scenarios. This value is much shorter than typical zone 2 total clearing times (~30 cycles). If shorter zone 2 delays are used, such as 15 cycles (~20 cycles total clearing time), the results show some minor improvement but do not meet the performance criteria.

Detailed results for all analysis and scenarios are presented in the following sub-sections.

Security constraint definitions and notes:

- Ramp Rate: The total ramp rate required for the system as a whole including thermal generation and energy storage systems.
- Regulating Reserves (Day): The regulating reserves due to wind and PV generation.
- Regulating Reserves (Night): The regulating reserves due to wind generation.
- Contingency Reserves: The size of additional ESS required to meet the performance criteria.
- 30 Minute Reserves: The largest unit contingency based on the minimum number of thermal units required.
- The regulating reserves and the contingency reserves are individual requirements and should be summed together to arrive at the total required reserves.

	Capacity (MW)	Minimum # of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves
PV Level	78 MW						
Thermal Units	2 (on-line)	2	12.2 MW/min	32 MW Maximum	16 MW Maximum	20 MW	22 MW
Thermal units	3 (on-line)	3	12.2 MW/min	32 MW Maximum	16 MW Maximum	20 MW	25 MW

Table D-9. 2019 Scenario 1 Security Constraints

	Capacity (MW)	Minimum # of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves
PV Level	89 MW						
Thermal Units	2 (on-line)	2	13.6 MW/min	34 MW Maximum	16 MW Maximum	25 MW	25 MW
Thermal units	3 (on-line)	3	13.6 MW/Min	34 MW Maximum	16 MW Maximum	20 MW	25 MW

Table D-10. 2025 Scenario 2 Security Constraints

	Capacity (MW)	Minimum # of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves
PV Level	89 MW						
Thermal Units	2 (on-line)	2	14.6 MW/min	21 MW Maximum	3 MW Maximum	25 MW	22 MW
Thermal units	3 (on-line)	3	14.6 MW/min	21 MW Maximum	3 MW Maximum	20 MW	25 MW

Table D-11. 2025 Scenario 3 Security Constraints

	Capacity (MW)	Minimum # of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves
PV Level	89 MW						
Thermal Units	2 (on-line)	2	17.6 MW/min	54 MW Maximum	36 MW Maximum	25 MW	22 MW
Thermal units	3 (on-line)	3	17.6 MW/min	54 MW Maximum	36 MW Maximum	20 MW	25 MW

Table D-12. 2025 Scenario 4 Security Constraints

Contingency Reserves

The required contingency reserves are based on the size of ESS required to meet the performance criteria for all disturbances and time periods throughout the day. Since zone 2 clearing times for line faults are beyond the critical clearing times, the contingency reserves are solely based on unit trip results. As unit commitments were varied by one unit, the difference in ESS size ranged approximately 5–10 MW. The commitment with the smaller number of thermal units online required this increased amount.

The contingency reserve results for each scenario are summarized below. Some reasonable approximations based on experience were used while interpreting the results in order to determine the minimum required size. Tables showing the results of the larger unit trips and defining results are also provided. The tables indicate the case, time period, disturbance, and the minimum and maximum frequencies. The number of stages of load shedding is defined by the fill color of each minimum frequency results. No color indicates no load shedding.

- Scenario 1: 20 MW (all commitments)
- Scenario 2: 20 MW, 25 MW (less one unit)
- Scenario 3: 20 MW, 25 MW (less one unit) Note that total amount of ESS size required is the sum of the contingency ESS and the regulation coming from the Lalamilo wind generation.
- Scenario 4: 20 MW, 25 MW (less one unit)

UFLS Stages:
1
2
3
4

Table D-13. UFLS Stages Indication

Outage/Fault	Load/Wind Scenario	No. Units	Max/Min Frequencies (Hz) Initial Setup Max	Initial Setup Min	10 MW ESS Max	10 MW ESS Min	15 MW ESS Max	15 MW ESS Min	20 MW ESS Max	20 MW ESS Min
KEAH4	Min/High	3	60.0	58.5	60.0	59.0				
	Min/Low	3	60.0	58.6						
	Day Min/High	3	60.0	58.4	60.0	58.4	60.0	58.5	60.0	58.7
	Day Min/Low	3	60.0	57.9	60.0	57.9	60.0	58.0	60.0	58.7
	Day Max/High	3	60.0	58.3	60.0	58.4	60.0	58.5	60.0	58.7
	Day Max/Low	4	60.0	58.4			60.0	58.6		
	Max/High	7	60.0	59.1						
	Max/Low	7	60.1	58.8						
	Max/High	6	60.2	58.8						
PGV1	Min/High	3	60.0	59.1						
	Min/Low	3	60.0	59.2						
	Min/High	2	60.0	58.8						
	Day Min/High	3	60.0	58.7	60.0	58.7				
	Day Min/Low	3	60.0	58.7	60.0	58.7				
	Day Min/High	2	60.0	58.3	60.0	58.6				
	Day Max/High	3	60.0	58.7	60.0	58.7				
	Day Max/Low	4	60.0	59.3						
	Max/High	7	60.0	59.6						
	Max/Low	7	60.0	59.5						
	Max/High	6	60.0	59.4						
HUHONUA	Min/High	3	60.0	58.6						
	Min/Low	3	60.0	58.7						
	Min/High	2	60.0	58.5	60.0	58.6	60.0	58.8		
	Day Min/High	3	60.0	58.4	60.0	58.5	60.0	58.6	60.0	58.8
	Day Min/Low	3	60.0	58.2	60.0	58.3	60.0	58.6	60.0	58.7
	Day Min/High	2	60.0	57.7	60.0	58.0	60.0	58.4	60.0	58.7
	Day Max/High	3	60.0	58.5	60.0	58.5	60.0	58.7	60.0	58.8
	Day Max/Low	4	60.0	58.7			60.0	58.7		
	Max/High	7	60.0	59.2						
	Max/Low	7	60.0	59.2						
	Max/High	6	60.0	59.1						
APOLLO	Min/High	3	60.0	58.7						
	Min/High	2	60.0	58.6	60.0	58.7	60.0	58.8		
	Day Min/High	3	60.0	58.6	60.0	58.6	60.0	58.7		
	Day Min/High	2	60.0	57.9	60.0	58.0	60.0	58.5	60.0	58.7
	Day Max/High	3	60.0	58.6	60.0	58.6	60.0	58.7		
	Max/High	7	60.0	59.3						
	Max/High	6	60.0	59.2						

Table D-14. 2019 Scenario 1 Summary Results

Outage/Fault	Load/Wind Scenario	No. Units	Max/Min Frequencies (Hz)									
			Initial Setup		10 MW ESS		15 MW ESS		20 MW ESS		25 MW ESS	
			Max	Min	Max	Min	Max	Min	Max	Min	Max	Min
	Min/Low	4	60.0	58.7								
	Day Max/High	4	60.0	58.4	60.0	58.5	60.0	58.7				
	Day Max/Low	5	60.0	58.5	60.0	58.6						
	Day Max/Low	4	60.0	58.4			60.0	58.5	60.0	58.7		
	Max/High	7	60.0	59.1								
	Max/Low	8	60.2	58.8								
KEAH4	Max/High	6	60.1	58.7								
	Max/Low	7	60.2	58.8								
	Day Max/Low	5	60.0	58.5								
	Max/High	7	60.0	59.1								
	Max/Low	8	60.2	58.8								
	Max/High	6	60.1	58.7								
	Max/Low	7	60.1	58.8								
	Min/High	3	60.0	58.7								
	Min/Low	4	60.0	58.7								
	Min/Low	3	60.0	58.7								
	Day Min/High	3	60.0	58.6								
HUHONUA	Day Min/Low	3	60.0	58.4			60.0	58.5				
	Day Max/High	4	60.0	58.6								
	Day Max/Low	5	60.0	58.6								
	Day Max/High	3	60.0	58.4			60.0	58.6				
	Day Max/Low	4	60.0	58.6								
	Min/High	3	60.0	58.7								
	Min/High	2	60.0	58.7								
	Day Min/High	3	60.0	58.7								
	Day Min/High	2	60.0	58.5								
APOLLO	Day Max/High	4	60.0	58.7								
	Day Max/High	3	60.0	58.5			60.0	58.7				
	Max/High	7	60.0	59.3								
	Max/High	6	60.0	59.1								
	Min/High	3	60.0	58.5	60.0	58.8						
	Min/Low	4	60.0	58.5								
	Min/High	2	60.0	58.5								
	Min/Low	3	60.0	58.7								
	Day Min/High	3	60.0	58.4			60.0	58.5	60.0	58.7		
	Day Min/Low	3	60.0	58.0			60.0	58.0	60.0	58.6		
	Day Min/High	2	60.0	58.1					60.0	58.5		
GEOWEST	Day Min/Low	2	60.0	57.9					60.0	58.3	60.0	58.7
	Day Max/High	4	60.0	58.4	60.0	58.5						
	Day Max/Low	5	60.0	58.5	60.0	58.7						
	Day Max/High	3	60.4	58.0			60.0	58.4	60.0	58.7		
	Day Max/Low	4	60.0	58.4			60.0	58.6				
	Max/High	7	60.0	59.0								
	Max/Low	8	60.0	59.0								
	Max/High	6	60.2	58.7								
	Max/Low	7	60.0	59.0								

Table D-15. 2025 Scenario 2 Summary Results

Outage/Fault	Load/Wind Scenario	No. Units	Max/Min Frequencies (Hz) Initial Setup Max	Min
KEAH4	Max/High	6	60.0	59.2
KEAH5	Max/High	6	60.0	59.2
HEP1	Max/High	6	60.0	59.2
PGV1	Min/High	2	60.0	59.4
PGV1	Day Min/High	2	60.0	59.4
	Day Max/High	2	60.0	59.4
	Max/High	6	60.0	59.6
HUHONUA	Min/High	2	60.0	58.9
	Day Min/High	2	60.0	58.7
	Day Max/High	2	60.0	58.7
	Max/High	6	60.0	59.3
APOLLO	Min/High	2	60.0	59.1
	Day Min/High	2	60.0	58.8
	Day Max/High	2	60.0	58.7
	Max/High	6	60.0	59.3
LALWIND	Min/High	2	60.0	59.7
	Day Min/High	2	60.0	59.6
	Day Max/High	2	60.0	59.6
	Max/High	6	60.0	59.7

Table D-16. 2025 Scenario 3 Summary Results

Outage/Fault	Load/Wind Scenario	No. Units	Max/Min Frequencies (Hz)							
			Initial Setup		10 MW ESS		15 MW ESS		20 MW ESS	
			Max	Min	Max	Min	Max	Min	Max	Min
KEAH4	Min/Low	4	60.0	58.4	60.0	58.7				
	Min/Low	3	60.0	58.7						
	Day Min/Low	3	60.0	58.0			60.0	58.0	60.0	58.6
	Day Max/Low	4	60.0	58.3	60.0	58.4	60.0	58.6		
	Max/High	5	60.1	58.7						
	Max/Low	8	60.3	58.8						
	Max/Low	8	60.3	58.8						
KEAH5	Min/Low	4	60.0	58.7	60.0	59.2				
	Day Max/Low	4	60.0	58.4	60.0	58.4	60.0	58.7		
	Max/High	5	60.1	58.7						
	Max/Low	8	60.2	58.8						
HEP1	Max/High	5	60.1	58.7						
	Max/Low	8	60.0	59.1						
PGV1	Min/High	2	60.5	58.5	60.0	58.9				
	Min/Low	4	60.3	58.8	60.0	59.3				
	Min/Low	3	60.0	59.3						
	Day Min/High	2	60.0	58.7						
	Day Min/Low	3	60.0	59.3						
	Day Max/High	2	60.0	58.6	60.0	58.6				
	Day Max/Low	4	60.0	58.8	60.0	59.3				
	Max/High	5	60.0	59.3						
	Max/Low	8	60.0	59.6						
HUHONUA	Min/High	2	60.0	58.1	60.0	58.5				
	Min/Low	4	60.0	58.5	60.0	58.8				
	Min/Low	3	60.0	58.8						
	Day Min/High	2	60.0	58.4			60.0	58.5		
	Day Min/Low	3	60.0	58.6			60.0	58.6		
	Day Max/High	2	60.0	58.3	60.0	58.3	60.0	58.5		
	Day Max/Low	4	60.0	58.5	60.0	58.6	60.0	58.7		
	Max/High	5	60.5	58.7						
	Max/Low	8	60.0	59.3						
APOLLO	Min/High	2	60.0	58.3	60.0	58.7				
	Day Min/High	2	60.0	58.5			60.0	58.6		
	Day Max/High	2	60.0	58.4	60.0	58.4	60.0	58.6		
	Max/High	5	60.4	58.8						
LALWIND	Min/High	2	60.2	58.7	60.0	59.5				
	Day Min/High	2	60.0	58.6			60.0	58.7		
	Day Max/High	2	60.0	58.4	60.0	58.4	60.0	58.7		
	Max/High	5	60.0	58.9						

Table D-17. 2025 Scenario 4 Summary Results

Critical Clearing Time

The critical clearing time for all scenarios was found to be approximately 11 cycles. This value is much shorter than typical zone 2 clearing times (~30 cycles) employed at Hawai'i Electric Light. The worst case line faults were found to be in the Keahole and HEP areas, typically at higher generation levels.

EPS recommends that Hawai'i Electric Light further evaluate the zone 2 timing and critical clearing times once the future generation and renewable energy issues have been solidified. No zone 1 faults were found to exceed the performance criteria or cause any instability issues. Zone 2 faults with reduced delay times (15 cycles) showed some improvement, but did not meet the performance criteria. However, the 15 cycle clearing time may provide some security in actual practice as opposed to studies of the boundary conditions that is not present using the existing clearing times.

Ramp Rates

The required ramp rates for each scenario are listed below. The values are based on the amount of wind and PV generation capacity. It is known that Hawaiʻi Electric Light's generating units cannot support these ramp rate values on a sustained basis under practical unit commitments. Achieving these ramp rates will require that Hawaiʻi Electric Light utilize the short-term (emergency) ramping capabilities on its combustion turbines, and that Hu Honua and geothermal plants achieve a 2 MW/min ramp rate. It is assumed that the addition of the ESS will provide the addition ramping capabilities necessary to meet the total ramp rate. This will require additional support from the contingency reserve ESS, however, so long as the regulation capacity is available on the units, the degradation of contingency reserves should be short-term.

- Scenario 1: 12.2 MW/min
- Scenario 2: 13.6 MW/min
- Scenario 3: 14.6 MW/min (75% regulating capacity for Lalamilo)
- Scenario 4: 17.6 MW/min

Regulating Capacity

The required regulating capacity is a calculation based on the amount of available wind capacity and PV energy with a minimum value of 6 MW. Other studies have concluded that up to 50% of the available wind capacity should be applied towards the required regulating capacity. When the actual wind output is less than 50% of capacity, a 1:1 MW/MW ratio should be applied. For instance if the wind capacity is 100 MW, a 25 MW output would require 25 MW of reserves, a 75 MW output would require 1:1 MW up to the maximum 50% value of 50 MW. The amount of regulating capacity required due to the amount of available PV energy is 20%.

The maximum required capacities are listed below for each scenario with and without PV availability (day/night). Note that the amount of regulation for Scenario 1 and Scenario 2 is identical for common years due to the lack of change in renewable generation. Scenario 3 includes 40 MW of self-regulated wind with 75% regulation capacity. A 10 MW (25%) output of the Lalamilo wind is assumed for these results.

With a 10 MW output, 17.5 MW total is available for regulation from Lalamilo at 100% wind capacity.

- Scenario 1: 32 MW/16 MW (Wind: 50%@ 31 MW, PV: 20%@78 MW)
- Scenario 2: 34 MW/16 MW (Wind: 50%@ 31 MW, PV: 20%@89 MW)
- Scenario 3: 21 MW/3 MW (Wind: 50%@ 41 MW, PV: 20%@89 MW)
- Scenario 4: 54 MW/36 MW (Wind: 50%@ 71 MW, PV: 20%@89 MW)

HAWAI'I ELECTRIC LIGHT 2030 CASES

Case Descriptions

The 2030 cases represent the final year of this study. The key difference between the intermediate cases is the amount of forecasted distributed PV. The amount of distributed PV found in 2030 is expected to be 97 MW (85% of capacity). The load levels for the daily load periods do not substantially change from the 2019 levels and are lower than the 2025 levels (1–6 MW).

Similar to the intermediate cases, the amount of wind generation does not change for generation Scenario 1 and Scenario 2. 40 MW of wind capacity is added for Scenarios 3 and 4. The load and renewable generation capacities are summarized in the following table for the year 2030.

Time Periods	Study Year 2030
Min	87
Min Day	152
Max Day	184
Max	193
PV Capacity	114
85% PV Capacity	97
Initial Wind Capacity	31

Table D-18. 2030 Case Load Levels (MW)

Generation Dispatches

The dispatches for all generation scenarios and time periods are provided in the following tables. The total amount of generation and initial estimated ESS size is included along with each individual unit output.

	Min - 87 MW			Min Day - 152 MW			Max Day - 184 MW		Max - 193 MW		
	High Wind		Low Wind	High Wind		Low Wind	High Wind	Low Wind	High Wind		Low Wind
Generation	3 Units	2 Units	3 Units	3 Units	2 Units	3 Units	3 Units	4 Units	7 Units	6 Units	7 Units
Keahole CT-4	15.0	-	18.0	17.5	-	17.3	18.0	19.0	18.5	19.0	19.0
Keahole CT-5	-	-	-	-	-	-	-	19.0	18.5	19.0	19.0
Keahole ST-7	3.8		4.5	4.4		4.3	4.5	13.3	13.0	13.3	13.3
Keahole 1CTCC	18.8		22.5	21.9		21.6	22.5				
Keahole 2CTCC								51.3	50.0	51.3	51.3
PGV Total	27.0	32.0	32.3	30.0	30.0	30.0	30.0	30.0	30.0	32.0	37.0
Hu Honua	15.0	18.5	20.5	20.5	18.5	20.5	20.5	20.5	20.5	20.5	20.5
Hill Unit No. 6	-	-	-	-	-	-	-	-	13.0	-	19.5
HEP CT1	-	-	-	-	-	-	-	-	19.0	19.5	19.5
HEP CT2	-	-	-	-	-	-	-	-	19.0	19.5	19.5
HEP ST									16.8	17.3	17.3
HEP 1 UNIT CC											
HEP 2 UNITS CC									54.8	56.3	56.3
As-availables	1.8	14.7	15.2	2.8	3.4	1.3	8.8	5.5	2.2	10.5	15.5
HRD	10.5	10.5	-	10.5	10.5	-	10.5	-	10.5	10.5	-
Apollo	20.5	20.5	-	20.5	20.5	-	20.5	-	20.5	20.5	-
Distributed PV	-	-	-	53.0	78.0	81.0	79.0	79.0	-	-	-
Total Generation	93.6	96.2	90.5	159.2	160.9	154.4	191.8	186.3	201.5	201.6	200.1
ESS for Cont. Res.	-	7.0	10.0	9.0	6.0	8.0	9.0	11.0	-	2.0	3.0

Table D-19. 2030 Scenario 1 Dispatch (MW)

	Min - 87 MW		Min Day - 152 MW		Max Day - 184 MW				Max - 193 MW		
	High Wind	Low Wind	High Wind	Low Wind	High Wind		Low Wind		High Wind		Low Wind
Generation	3 Units	3 Units	3 Units	3 Units	4 Units	3 Units	4 Units	3 Units	7 Units	6 Units	7 Units
Keahole CT-4	-	-	-	-	9.6	-	17.0	-	17.0	19.0	19.0
Keahole CT-5	-	-	-	-	-	-	-	-	17.0	19.0	19.0
Keahole ST-7					2.4		4.3		11.9	13.3	13.3
Keahole 1CTCC					12.0		21.3				
Keahole 2CTCC									45.9	51.3	51.3
PGV Total	30.0	30.0	27.0	30.0	30.0	30.0	30.0	36.0	35.0	37.0	36.0
Hu Honua	13.5	20.0	10.0	12.0	11.0	16.0	18.5	20.5	20.0	20.0	20.5
Hill Unit No. 6	-	-	-	-	-	-	-	-	-	-	-
HEP CT1	-	-	-	-	-	-	-	-	16.0	18.5	19.0
HEP CT2	-	-	-	-	-	-	-	-	16.0	-	19.0
HEP ST									14.2	8.2	16.8
HEP 1 UNIT CC										26.7	
HEP 2 UNITS CC									46.2		54.8
Waiau 350 KW Unit	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Waiau 750 KW Unit	0.5	0.5	0.5	0.5	0.1	0.5	0.2	0.5	0.2	0.5	0.5
Puueo 750 KW Unit	0.5	0.5	0.5	0.5	0.1	0.2	0.2	0.5	0.2	0.5	0.5
Puueo new Unit	0.5	2.0	0.2	0.1	0.2	0.5	0.5	1.5	0.2	0.5	1.0
Wailuku 1	0.3	5.5	0.5	0.5	0.2	2.5	1.4	5.5	0.8	4.5	3.1
Wailuku 2	0.5	5.0	0.5	0.5	0.2	2.0	1.0	5.5	0.5	4.5	3.0
As-availables	2.5	13.7	2.4	2.3	1.0	5.9	3.5	13.7	2.1	10.7	8.3
New Geothermal	18.0	23.5	7.0	14.3	13.0	16.0	17.0	22.0	20.0	23.0	23.5
HRD	8.0	1.0	10.5	1.0	10.5	10.5	1.0	1.0	10.5	10.5	1.0
Apollo	20.5	2.0	20.5	2.0	20.5	20.5	2.0	2.0	20.5	20.5	2.0
Distributed PV	-	-	82.0	93.0	93.0	93.0	93.0	93.0	-	-	-
ESS for Cont. Res.	-	10.0	-	-	-	-	-	11.0	-	-	-
Total Generation	92.5	90.2	159.4	154.6	191.0	191.9	186.3	188.2	200.2	199.7	197.4

Table D-20. 2030 Scenario 2 Dispatch (MW)

	Min - 87 MW			Min Day - 152 MW		Max Day - 184 MW			Max - 193 MW	
	High Wind		Low Wind	High Wind	Low Wind	High Wind		Low Wind	High Wind	Low Wind
Generation	3 Units	2 Units	3 Units	2 Units	2 Units	3 Units	2 Units	3 Units	6 Units	7 Units
Keahole CT-4	8.0	-	17.0	-	-	9.6	-	18.8	17.0	19.0
Keahole CT-5	-	-	-	-	-	-	-	-	17.0	19.0
Keahole ST-7	2.0		4.3			2.4		4.7	11.9	13.3
Keahole 1CTCC	10.0		21.3			12.0		23.5		
Keahole 2CTCC									45.9	51.3
PGV Total	27.0	27.0	30.0	30.0	30.0	30.0	30.0	30.0	32.0	36.0
Hu Honua	10.0	10.0	18.5	10.0	15.0	10.0	14.0	19.5	20.0	20.5
Hill Unit No. 6	-	-	-	-	-	-	-	-	-	19.0
HEP CT1	-	-	-	-	-	-	-	-	17.0	19.0
HEP CT2	-	-	-	-	-	-	-	-	17.0	19.0
HEP ST									15.0	16.8
HEP 1 UNIT CC										
HEP 2 UNITS CC									49.0	54.8
As-availables	3.1	6.5	13.2	3.1	11.2	3.6	4.9	14.4	3.4	10.9
HRD	10.5	10.5	1.0	10.5	1.0	10.5	10.5	1.0	10.5	1.0
Apollo	12.0	20.5	2.0	20.5	2.0	20.5	20.5	2.0	20.5	2.0
New Wind 1/Lalamino	10.0	10.0	2.0	10.0	2.0	10.0	10.0	2.0	10.0	2.0
New Wind 2/Lalamino	10.0	10.0	2.0	10.0	2.0	10.0	10.0	2.0	10.0	2.0
Distributed PV	-	-	-	66.0	93.0	85.0	93.0	93.0	-	-
ESS for Cont. Res.	-	-	6.0	-	6.0	-	-	11.0	-	-
Total Generation	92.6	94.5	90.0	160.1	156.2	191.6	192.9	187.4	201.3	199.5

Table D-21. 2030 Scenario 3 Dispatch (MW)

	Min - 87 MW			Min Day - 152 MW		Max Day - 184 MW			Max - 193 MW	
	High Wind		Low Wind	High Wind	Low Wind	High Wind		Low Wind	High Wind	Low Wind
Generation	3 Units	2 Units	3 Units	2 Units	2 Units	3 Units	2 Units	3 Units	5 Units	7 Units
Keahole CT-4	8.0	-	17.0	-	-	9.6	-	18.8	17.0	19.0
Keahole CT-5	-	-	-	-	-	-	-	-	17.0	19.0
Keahole ST-7	2.0		4.3			2.4		4.7	11.9	13.3
Keahole 1CTCC	10.0		21.3			12.0		23.5		
Keahole 2CTCC									45.9	51.3
PGV 1	12.0	13.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0
PGV 2	9.0	10.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
PGV new1	1.5	2.0	2.5	2.5	2.5	2.5	2.5	2.5	5.0	5.5
PGV new2	1.5	2.0	2.5	2.5	2.5	2.5	2.5	2.5	5.0	5.5
PGV Total	24.0	27.0	30.0	30.0	30.0	30.0	30.0	30.0	35.0	36.0
Hu Honua	10.0	10.0	18.5	10.0	15.0	10.0	10.0	19.5	20.0	20.5
Hill Unit No. 6	-	-	-	-	-	-	-	-	-	19.0
HEP CT1	-	-	-	-	-	-	-	-	17.0	19.0
HEP CT2	-	-	-	-	-	-	-	-	-	19.0
HEP ST									7.5	16.8
HEP 1 UNIT CC									24.5	
HEP 2 UNITS CC										54.8
As-availables	2.6	2.1	13.3	3.5	11.4	3.8	4.8	14.5	4.2	10.9
HRD	1.0	8.0	1.0	10.5	1.0	10.5	10.5	1.0	10.5	1.0
Apollo	2.0	5.0	2.0	20.5	2.0	20.5	20.5	2.0	20.5	2.0
New Wind 1/Lalamino	20.0	20.0	2.0	20.0	2.0	20.0	20.0	2.0	20.0	2.0
New Wind 2/Lalamino	20.0	20.0	2.0	20.0	2.0	20.0	20.0	2.0	20.0	2.0
Distributed PV	-	-	-	46.0	93.0	65.0	77.0	93.0	-	-
ESS for Cont. Res.	2.0	17.0	6.0	20.0	6.0	5.0	18.0	11.0	4.0	-
Total Generation	89.6	92.1	90.1	160.5	156.4	191.8	192.8	187.5	200.6	199.5

Table D-22. 2030 Scenario 4 Dispatch (MW)

Results

The results are summarized in the security constraints tables below. Similar to the intermediate cases results, the 2030 results indicate that an ESS sized in the range of 20–25 MW will cover all unit trips for all four of the generation scenarios. This range correlates with the largest unit contingencies. Note that the increments in ESS size were 5 MW. Thus the maximum required size may be slightly smaller and the differences between differing unit commitments may not be as evident (<5 MW).

Also similar to the intermediate case results, the critical clearing time is roughly 11 cycles for all generation scenarios. This value is much shorter than typical zone 2 total clearing times (~30 cycles). If shorter zone 2 delays are used, such as 15 cycles (~20 cycles total clearing time), the results show some minor improvement but do not meet the performance criteria.

Detailed results for all analysis and scenarios are presented in the following sub-sections.

	Capacity (MW)	Minimum # of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves
PV Level	97 MW						
Thermal Units	2 (on-line)	2	14.5 MW/min	35 MW Maximum	16 MW Maximum	20 MW	22 MW
Thermal units	3 (on-line)	3	14.5 MW/min	35 MW Maximum	16 MW Maximum	20 MW	25 MW

Table D-23. 2030 Scenario 1 Security Constraints

	Capacity (MW)	Minimum # of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves
PV Level	97 MW						
Thermal Units	2 (on-line)	2	14.5 MW/min	35 MW Maximum	16 MW Maximum	25 MW	25 MW
Thermal units	3 (on-line)	3	14.5 MW/min	35 MW Maximum	16 MW Maximum	20 MW	25 MW

Table D-24. 2030 Scenario 2 Security Constraints

	Capacity (MW)	Minimum # of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves
PV Level	97 MW						
Thermal Units	2 (on-line)	2	15.5 MW/min	23 MW Maximum	3 MW Maximum	25 MW	22 MW
Thermal units	3 (on-line)	3	15.5 MW/min	23 MW Maximum	3 MW Maximum	20 MW	25 MW

Table D-25. 2030 Scenario 3 Security Constraints

	Capacity (MW)	Minimum # of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves
PV Level	97 MW						
Thermal Units	2 (on-line)	2	18.5 MW/min	55 MW Maximum	36 MW Maximum	25 MW	22 MW
Thermal units	3 (on-line)	3	18.5 MW/min	55 MW Maximum	36 MW Maximum	20 MW	25 MW

Table D-26. 2030 Scenario 4 Security Constraints

Contingency Reserves

The required contingency reserves are based on the size of ESS required to meet the performance criteria for all disturbances and time periods throughout the day. Since zone 2 clearing times for line faults are beyond the critical clearing times, the contingency reserves are solely based on unit trip results. As unit commitments were varied by one unit, the difference in ESS size ranged approximately 5–10 MW. The commitment with the smaller number of thermal units online required this increased amount.

The contingency reserve results for each scenario are summarized below. Some engineering judgment was used while interpreting the results in order to determine the minimum required size. Tables showing the results of the larger unit trips and defining results are also provided. The tables indicate the case, time period, disturbance, and the minimum and maximum frequencies. The number of stages of load shedding is defined by the fill color of each minimum frequency results. No color indicates no load shedding.

- Scenario 1: 20 MW (all commitments)
- Scenario 2: 20 MW, 25 MW (less one unit)
- Scenario 3: 20 MW, 25 MW (less one unit)
- Scenario 4: 20 MW, 25 MW (less one unit)

UFLS Stages:
1
2
3
4

Table D-27. UFLS Stages Indication

Outage/Fault	Load/Wind Scenario	No. Units	Max/Min Frequencies (Hz) Initial Setup Max	Initial Setup Min	10 MW ESS Max	10 MW ESS Min	15 MW ESS Max	15 MW ESS Min	20 MW ESS Max	20 MW ESS Min
KEAH4	Min/High	3	60.0	58.5	60.0	58.9				
	Min/Low	3	60.0	58.6						
	Day Min/High	3	60.0	58.4	60.0	58.4	60.0	58.5	60.0	58.7
	Day Min/Low	3	60.0	57.9	60.0	57.9	60.0	58.0	60.0	58.7
	Day Max/High	3	60.0	58.3	60.0	58.4	60.0	58.5	60.0	58.7
	Day Max/Low	4	60.0	58.4			60.0	58.5	60.0	58.7
	Max/High	7	60.0	59.1						
	Max/Low	7	60.1	58.8						
	Max/High	6	60.2	58.8						
HEP1	Max/High	7	60.0	59.1						
	Max/Low	7	60.0	59.0						
	Max/High	6	60.3	58.8						
PGV1	Min/High	3	60.0	59.1						
	Min/Low	3	60.0	59.2						
	Min/High	2	60.0	58.8						
	Day Min/High	3	60.0	58.7	60.0	58.7				
	Day Min/Low	3	60.0	58.7	60.0	58.7				
	Day Min/High	2	60.5	58.0	60.0	58.6				
	Day Max/High	3	60.0	58.7	60.0	58.7				
	Day Max/Low	4	60.0	59.3						
	Max/High	7	60.0	59.6						
	Max/Low	7	60.0	59.5						
	Max/High	6	60.0	59.4						
HUHONUA	Min/High	3	60.0	58.6	60.0	59.0				
	Min/Low	3	60.0	58.7						
	Min/High	2	60.0	58.5	60.0	58.6	60.0	58.8	60.0	59.0
	Day Min/High	3	60.0	58.4	60.0	58.5	60.0	58.6	60.0	58.8
	Day Min/Low	3	60.0	58.2	60.0	58.3	60.0	58.6	60.0	58.8
	Day Min/High	2	60.0	57.8	60.0	57.9	60.0	58.4	60.0	58.7
	Day Max/High	3	60.0	58.5	60.0	58.5	60.0	58.7	60.0	58.8
	Day Max/Low	4	60.0	58.7			60.0	58.7	60.0	58.9
	Max/High	7	60.0	59.2						
	Max/Low	7	60.0	59.2						
	Max/High	6	60.0	59.1						
APOLLO	Min/High	3	60.0	58.7	60.0	59.1				
	Min/High	2	60.0	58.6	60.0	58.7	60.0	58.8	60.0	59.0
	Day Min/High	3	60.0	58.6	60.0	58.6	60.0	58.7	60.0	58.9
	Day Min/High	2	60.0	57.7	60.0	57.9	60.0	58.0	60.0	58.7
	Day Max/High	3	60.0	58.6	60.0	58.6	60.0	58.7	60.0	58.9
	Day Max/Low	4	60.0	58.7						
	Max/High	7	60.0	59.3						
	Max/High	6	60.0	59.2						

Table D-28. 2030 Scenario 1 Summary Results

Outage/Fault	Load/Wind Scenario	No. Units	Max/Min Frequencies (Hz) Initial Setup Max	Initial Setup Min	10 MW ESS Max	10 MW ESS Min	15 MW ESS Max	15 MW ESS Min
KEAH4	Day Max/High	4	60.0	59.3				
	Day Max/Low	4	60.5	58.0	60.0	58.6		
	Max/High	7	60.0	59.2				
	Max/Low	7	60.2	58.8	60.0	59.2		
	Max/High	6	60.1	58.7				
	Max/High	7	60.0	59.2				
HEP1	Max/High	7	60.0	59.3				
	Max/Low	7	60.0	58.9				
	Max/High	6	60.0	58.7				
PGV1	Min/High	3	60.0	59.0				
	Min/Low	3	60.0	59.2	60.0	59.2		
	Day Min/High	3	60.0	58.7				
	Day Min/Low	3	60.0	58.6				
	Day Max/High	4	60.0	58.9				
	Day Max/Low	4	60.0	58.7				
	Day Max/High	3	60.0	58.5				
	Day Max/Low	3	60.0	58.8				
	Max/High	7	60.0	59.5				
	Max/Low	7	60.0	59.5				
	Max/High	6	60.0	59.3				
HUHONUA	Min/High	3	60.0	58.7				
	Min/Low	3	60.0	58.7	60.0	58.7	60.0	58.9
	Day Min/High	3	60.0	58.3	60.0	59.4		
	Day Min/Low	3	60.3	57.9	60.0	58.7		
	Day Max/High	4	60.0	58.6				
	Day Max/Low	4	60.0	58.3	60.0	58.7		
	Day Max/High	3	62.4	58.0	60.0	58.7		
	Day Max/Low	3	60.0	58.5			60.0	58.7
	Max/High	7	60.0	59.2				
	Max/Low	7	60.0	59.2				
	Max/High	6	60.0	58.9				
APOLLO	Min/High	3	60.0	58.7				
	Min/Low	3	60.0	59.9	60.0	59.9		
	Day Min/High	3	60.0	58.4	60.0	58.8		
	Day Min/Low	3	60.0	59.9	60.0	59.9		
	Day Max/High	4	60.0	58.7				
	Day Max/Low	4	60.0	59.9	60.0	59.9		
	Day Max/High	3	60.0	58.2	60.0	58.7		
	Day Max/Low	3	60.0	59.9				
	Max/High	7	60.0	59.3				
	Max/Low	7	60.0	59.9				
	Max/High	6	60.0	59.1				
GEOWEST	Min/High	3	60.0	58.7				
	Min/Low	3	60.0	58.5	60.0	58.5	60.0	58.7
	Day Min/High	3	60.0	59.5				
	Day Min/Low	3	60.1	58.0	60.0	58.9		
	Day Max/High	4	60.0	58.7				
	Day Max/Low	4	60.0	58.3	60.0	58.7		
	Day Max/High	3	60.8	58.0	60.0	58.7		
	Day Max/Low	3	60.0	58.3			60.0	58.5
	Max/High	7	60.0	59.2				
	Max/Low	7	60.0	58.9				
	Max/High	6	60.2	58.7				

Table D-29. 2030 Scenario 2 Summary Results

Outage/Fault	Load/Wind Scenario	No. Units	Max/Min Frequencies (Hz)							
			Initial Setup		10 MW ESS		15 MW ESS		20 MW ESS	
			Max	Min	Max	Min	Max	Min	Max	Min
KEAH4	Min/High	3	60.0	59.3						
	Min/Low	3	60.0	58.5	60.0	58.7				
	Day Max/High	3	60.0	58.7						
	Day Max/Low	3	60.3	58.0			60.0	58.4	60.0	58.7
	Max/High	6	60.0	59.0						
	Max/Low	7	60.2	58.8						
PGV1	Min/High	3	60.0	59.2						
	Min/Low	3	60.0	59.2						
	Min/High	2	60.0	58.9						
	Day Min/High	2	60.0	58.4	60.0	58.9				
	Day Min/Low	2	60.0	58.5	60.0	59.3				
	Day Max/High	3	60.0	58.7						
	Day Max/Low	3	60.0	59.3						
	Day Max/High	2	60.0	58.3	60.0	59.3				
	Max/High	6	60.0	59.4						
	Max/Low	7	60.0	59.5						
HUHONUA	Min/High	3	60.3	58.8						
	Min/Low	3	60.0	58.7	60.0	58.8				
	Min/High	2	60.0	58.6						
	Day Min/High	2	60.0	58.1	60.0	58.6				
	Day Min/Low	2	60.1	57.8	60.1	57.9	60.0	58.6		
	Day Max/High	3	60.0	58.5						
	Day Max/Low	3	60.0	58.5			60.0	58.7	60.0	58.9
	Day Max/High	2	62.3	40.4	60.0	58.5	60.0	58.7		
	Max/High	6	60.0	59.1						
	Max/Low	7	60.0	59.2						
APOLLO	Min/High	3	60.0	59.3						
	Min/Low	3	60.0	59.9	60.0	59.9				
	Min/High	2	60.0	58.6						
	Day Min/High	2	60.0	58.1	60.0	58.7				
	Day Min/Low	2	60.0	59.9	60.0	59.9				
	Day Max/High	3	60.0	58.5						
	Day Max/Low	3	60.0	59.9						
	Day Max/High	2	60.0	57.9	60.0	58.6				
	Max/High	6	60.0	59.1						
	Max/Low	7	60.0	59.9						
LALWIND	Min/High	3	60.0	59.4						
	Min/Low	3	60.0	59.9						
	Min/High	2	60.0	59.2						
	Day Min/High	2	60.0	58.7						
	Day Min/Low	2	60.0	59.9						
	Day Max/High	3	60.0	59.4						
	Day Max/Low	3	60.0	59.9						
	Day Max/High	2	60.0	58.7						
	Max/High	6	60.0	59.7						
	Max/Low	7	60.0	59.9						

Table D-30. 2030 Scenario 3 Summary Results

Outage/Fault	Load/Wind Scenario	No. Units	Max/Min Frequencies (Hz) Initial Setup Max	Initial Setup Min	15 MW ESS Max	15 MW ESS Min	20 MW ESS Max	20 MW ESS Min
KEAH4	Min/High	3	60.0	59.4				
	Min/Low	3	60.0	58.5	60.0	58.8		
	Day Max/High	3	60.0	59.4				
	Day Max/Low	3	60.3	58.0	60.0	58.4	60.0	58.7
	Max/High	5	60.0	58.9				
	Max/Low	7	60.2	58.8				
PGV1	Min/High	3	60.0	59.3				
	Min/Low	3	60.0	59.2	60.0	59.5		
	Min/High	2	60.0	59.5				
	Day Min/High	2	60.0	59.5				
	Day Min/Low	2	60.0	58.5	60.0	59.4		
	Day Max/High	3	60.0	59.3				
	Day Max/Low	3	60.0	59.3	60.0	59.4		
	Day Max/High	2	60.0	59.4				
	Max/High	5	60.0	59.4				
	Max/Low	7	60.0	59.5				
HUHONUA	Min/High	3	60.0	58.9				
	Min/Low	3	60.0	58.7	60.0	59.1		
	Min/High	2	60.0	59.5				
	Day Min/High	2	60.0	59.5				
	Day Min/Low	2	60.1	57.8	60.0	58.7		
	Day Max/High	3	60.0	58.7				
	Day Max/Low	3	60.0	58.5	60.0	58.7		
	Day Max/High	2	60.0	59.5				
	Max/High	5	60.0	59.0				
	Max/Low	7	60.0	59.2				
APOLLO	Min/High	3	60.0	59.9				
	Min/Low	3	60.0	59.9				
	Min/High	2	60.0	59.8				
	Day Min/High	2	60.0	59.1				
	Day Min/Low	2	60.0	59.9				
	Day Max/High	3	60.0	58.7				
	Day Max/Low	3	60.0	59.9				
	Day Max/High	2	60.0	59.0				
	Max/High	5	60.0	59.1				
	Max/Low	7	60.0	59.9				
LALWIND	Min/High	3	60.0	58.8				
	Min/Low	3	60.0	59.9				
	Min/High	2	60.0	59.2				
	Day Min/High	2	60.0	59.1				
	Day Min/Low	2	60.0	59.9				
	Day Max/High	3	60.0	58.7				
	Day Max/Low	3	60.0	59.9				
	Day Max/High	2	60.0	59.0				
	Max/High	5	60.0	59.2				
	Max/Low	7	60.0	59.9				

Table D-31. 2030 Scenario 4 Summary Results

Critical Clearing Time

The critical clearing time for all scenarios was found to be approximately 11 cycles. This value is much shorter than typical zone 2 clearing times (~30 cycles). The worst case line faults were found to be in the Keahole and HEP areas, typically at higher generation levels.

EPS recommends that Hawai'i Electric Light further evaluate the zone 2 timing and critical clearing times once the future generation and renewable energy issues have been solidified. No zone 1 faults were found to exceed the performance criteria or cause any instability issues. Zone 2 faults with reduced delay times (15 cycles) showed some improvement, but did not meet the performance criteria in the boundary scenarios. However, 15 cycle clearing in actual operating conditions will likely avoid system stability issues that have been identified in the boundary cases.

Ramp Rates

The required ramp rates for each scenario are listed below. The values are based on the amount of wind and PV generation capacity. It is known that Hawai'i Electric Light's generating units cannot support these ramp rate values under practical unit commitments. It is assumed that the addition of the ESS will provide the addition ramping capabilities necessary to meet these rates.

- Scenario 1: 14.5 MW/min
- Scenario 2: 14.5 MW/min
- Scenario 3: 15.5 MW/min (75% regulating capacity for Lalamilo)
- Scenario 4: 18.5 MW/min

Regulating Capacity

The required regulating capacity is a calculation based on the amount of available wind capacity and PV energy with a minimum value of 6 MW. Other studies have concluded that up to 50% of the available wind capacity should be applied towards the required regulating capacity. When the actual wind output is less than 50% of capacity, a MW/MW ratio should be applied. For instance if the wind capacity is 100 MW, a 25 MW output would require 25 MW of reserves, a 75 MW output would require the maximum 50% value of 50 MW. The amount of regulating capacity required due to the amount of available PV energy is 20%.

The maximum required capacities are listed below for each scenario with and without PV availability (day/night). Note that the amount of regulation for Scenario 1 and Scenario 2 is identical for common years due to the lack of change in renewable generation. Scenario 3 includes 40 MW of self-regulated wind with 75% regulation capacity. A 10 MW (25%) output of the Lalamilo wind is assumed for these results. With a 10 MW output, 17.5 MW total is available for regulation from Lalamilo at 100% wind capacity.

- Scenario 1: 35 MW/16 MW (Wind: 50%@ 31 MW, PV: 20%@97 MW)
- Scenario 2: 35 MW/16 MW (Wind: 50%@ 31 MW, PV: 20%@97 MW)
- Scenario 3: 23 MW/3 MW (Wind: 50%@ 41 MW, PV: 20%@97 MW)
- Scenario 4: 55 MW/36 MW (Wind: 50%@ 71 MW, PV: 20%@97 MW)

HAWAI'I ELECTRIC LIGHT 2015/2016 OPERATION STUDIES

This portion of the study identifies the generation operating requirements for various generation and load scenarios under study for the Hawai'i Electric Light system. The 2015 and 2016 years were studied to help determine the operational impact that the forecast load and increased PV capacity has on the Hawai'i Electric Light generation operations. Sensitivity to the amount of legacy PV was also studied. The operating requirements were based on the system's response with criteria meeting one stage of UFLS and two stages of UFLS.

Methodology

The methodology used to help determine the generation operating requirements was similar to the security studies. The key difference was the generation commitment and dispatch was configured to meet the regulating reserves with all PV at its anticipated maximum output. Since the focus was the sensitivity to PV levels, the Min and Max loads and time periods were not included in the analysis. Although zone 1 and delayed fault clearing simulations were performed, unit trips were the focus due to the critical clearing time issues discussed in the security studies. The 2015 and 2106 systems were included in the study. The major generation change in this timeframe is the addition of Hu Honua.

The operating requirements to meet the stage 1 UFLS and stage 2 UFLS performance objectives were met, when necessary, using transfer tipping mitigation techniques. Reducing generator output was also explored for certain cases. The transfer tripping method simulated rapid load shedding upon the detection of a system disturbance. This results in a reduction in the amount of frequency decay and minimum frequency. The amount of load shedding included stage 1 or both stage 1 & 2 stages of the existing UFLS scheme. A seven cycle total clearing time was assumed for the transfer trip scheme.

To determine if any mitigation was necessary for the simulations, an initial set of results was created. For all simulations that resulted in UFLS beyond stage 1, subsequent simulations were performed using the transfer trip scheme. This method continued until the results showed a clear improvement in minimum frequency and reduction in the amount of PV being tripped. Typically, these minimum frequency values were greater than 59.3 Hz.

The sensitivity to the amount of legacy PV was included in the analysis. A capacity of 10 MW, consistent with the security studies, and a 13.1 MW (existing capacity) value was used. The legacy PV represents the capacity of PV that may not be able to be modified to provide improved ride-through trip settings. The remaining balance of existing and forecast PV is assumed to have extended ride-through settings. The legacy and extended ride-through settings used are detailed in the security studies portion of this report.

HAWAI'I ELECTRIC LIGHT CASE DESCRIPTIONS & RESULTS

Case Descriptions

The case descriptions are provided in the table below. The table includes the system load and renewable generation levels, net stage 1 and stage 2 UFLS values, and the individual unit commitments/dispatches used for the analysis. The unit commitment is based on the total system demand, a fixed amount of renewables, and meeting the regulating reserve requirements established as part of the security studies. The amount of variable generation was varied to make adjustments to attain the proper levels of regulating reserves and help create more severe system disturbances. Low values of variable generation helped to provide for higher dispatches while high values helped reduce the number of units committed.

	2015				2016			
	Min Day		Max Day		Min Day		Max Day	
	High	Low	High	Low	High	Low	High	Low
Load	140	140	179	179	145	145	179	179
PV	56	56	56	56	67	67	67	67
Wind	31	-	31	-	31	-	31	-
Regulation	27	24	27	13	29	31	29	14
Required Regulation	27	11	27	11	29	13	29	13
Net UFLS Stage 1	8.0	8.0	12.2	12.2	7.2	7.2	10.8	10.8
Net UFLS Stage 2	5.1	5.1	9.0	9.0	3.8	3.8	7.2	7.2
Net UFLS Stage 1&2	13.1	13.1	21.2	21.2	11.0	11.0	18.1	18.1
No. Units	3	4	4	5	3	4	4	4
CT4	9.0	14.5	17.0	18.0	8.0	12.5	13.0	17.5
CT5	-	14.5	8.0	18.0	-	12.5	13.0	17.5
PGV	30.0	30.0	32.0	30.0	30.0	30.0	30.0	35.0
Hu Honua	11.0	14.5	17.5	18.0	10.0	13.0	14.0	17.0
HEP CT1	-	-	-	18.0	-	-	-	
As-availables	8.4	2.1	16.4	2.9	4.5	3.1	8.8	15.8

Table D-32. Case Descriptions (MW)

Summary Results

The summary mitigation results are provided in the table below. The table includes the mitigation techniques required to meet the performance objectives. The results show that using the stated commitments, dispatches, and resultant amount of regulating reserves provided for a maximum stage 2 performance. No additional operational requirements are necessary. To limit the performance to stage 1, transfer tripping of stage 1 and stage 2 ("TT St 1&2) is required to cover all time periods, wind variations, and legacy PV levels studied. For 2015, the system can be limited to transfer tripping of stage 1 if the output of Keahole CT4 is limited to 15 MW or less during maximum day and high wind conditions.

The 2015 and 2016 security constraints tables are also provided. The contingency reserve values are based on the amount of the largest contingency creating the disturbance.

All faults with zone 1 clearing times result in a maximum of stage 1 UFLS. No mitigation is necessary. As discussed in the security studies, zone 2 with clearing times greater than 15 cycles exceed the critical clearing time of the system for several fault locations and conditions. This is true for the 2015/2016 system was well. The critical clearing time is roughly eleven cycles for all transmission lines.

Operating Requirements:	2015 Min Day High	2015 Min Day Low	2015 Max Day High	2015 Max Day Low	2016 Min Day High	2016 Min Day Low	2016 Max Day High	2016 Max Day Low
10 MW Legacy PV:								
Allow Stage 2	None	None	None	None	None	None	None	None
Allow Stage 1	TT St 1	TT St 1	TT St 1&2*	TT St 1	TT St 1	TT St 1	None	TT St 1&2
13 MW Legacy PV:								
Allow Stage 2	None	None	None	None	None	None	None	None
Allow Stage 1	TT St 1	TT St 1	TT St 1&2*	TT St 1	TT St 1&2	TT St 1	TT St 1	TT St 1&2

* Or TT St 1 & CT4<15 MW

Table D-33. Mitigation Summary Results

	Capacity (MW)	Minimum # of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves
PV Level	56 MW	3	9.6 MW/min	27 MW Maximum	16 MW Maximum	31 MW	27 MW
Thermal Units	3 (on-line)						

Table D-34. 2015 Security Constraints

	Capacity (MW)	Minimum # of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves
PV Level	67 MW	3	10.9 MW/min	29 MW Maximum	16 MW Maximum	29 MW	27 MW
Thermal Units	3 (on-line)						

Table D-35. 2016 Security Constraints

Detailed Results and Discussion

Detailed results showing the progression of mitigation for each system configuration are found in the four tables below. The top portion of the table shows the reference disturbances resulting in more than one stage of UFLS without any mitigation. All of these cases can be mitigated to meet the reliability objectives. The improvements can be seen in the minimum frequency value and amount of PV tripped during the disturbance.

Although the minimum frequency value stated does not precisely represent the frequency at every bus where UFLS can occur, it does give a good representation of the average frequency found throughout the system for these types of disturbances. It can be seen from the minimum frequency values that many of the reference simulation results are slightly under the stage 2 frequency setpoint of 58.5 Hz. Thus, the majority of exceptions can be mitigated to stage 1 performance by speeding up the clearing time for a stage 1 using the transfer trip scheme to trigger the UFLS instead of a frequency based scheme. Note that the number of stages listed for the non-reference simulations correspond to the amount of load shed and not the frequency setpoints normally used for these stages.

The difference in the amount of legacy PV in tables 5–3 and 5–4 is 2.6 MW. This difference is relatively small and does not indicate much of a difference in results for 2015. In 2016, there is some difference in the maximum day, high wind cases. Similar to the majority of results, these stage 2 exceptions are slightly under the stage 2 frequency setpoint.

The commitments shown represent the final configurations studied in detail to determine the operating requirements. Other commitments, that could also meet the regulating reserve requirements and unit minimums, were initially evaluated and included either one more or one less unit committed. With one less unit, these configurations indicated that other, more extreme, mitigation techniques would be required to achieve the proper level of system performance. With one more unit, the regulating reserve levels were larger with much improved system performance often with results indicating only stage 1 or non-load shedding.

The final unit commitments and simulation results help to form the boundary conditions for the generation operating requirements, but do not encompass all of the evaluation that is necessary for final operations of the units. The unit commitments and dispatches, amount of regulating reserves, and simulation results are very specific to the amount of PV and wind generation assumed for each case. Variations for these assumptions must be considered for actual operations.

The number of units online (single plant for PGV) ranges from 3–5 for the time periods and assumptions studied. However, as previously stated, the variable generation has been adjusted to help form the boundary conditions. For instance, although only four units are committed for the maximum day load and low wind, the variable output is very high thus allowing sufficient regulation from the thermal generation units. If the variable generation has lower output or the PV is not at 85% capacity, then another unit may need to be placed online to achieve the desired system performance. Similarly, a unit may be able to be placed offline if the variable generation and wind output are at higher levels such as in the minimum day, low wind cases.

Load/Wind Scenario	Unit trip	Stages Tripped	Min Freq Hz	Net Load/PV Tripped MW	Load Tripped MW	PV Tripped MW
Min Day/High Wind	APOLLO	2	58.47	7.0	29.2	(22.2)
	HUHONUA	2	58.44	7.0	29.2	(22.2)
Min Day/Low Wind	HUHONUA	2	58.42	7.0	29.2	(22.2)
	KEAH4	2	58.41	7.0	29.2	(22.2)
	KEAH5	2	58.40	7.0	29.2	(22.2)
Max Day/High Wind	HEP1	2	58.49	15.2	37.4	(22.2)
	KEAH5	2	58.47	17.2	36.1	(18.9)
Max Day/Low Wind	HUHONUA	2	58.45	15.2	37.4	(22.2)
	KEAH4	2	58.38	15.2	37.4	(22.2)
Transfer Trip Stage 1						
Min Day/High Wind	APOLLO	1	58.80	0.6	14.98	(14.41)
	HUHONUA	1	59.69	8.0	14.98	(6.96)
Min Day/Low Wind	HUHONUA	1	59.42	8.0	14.98	(6.96)
	KEAH4	1	59.33	8.0	14.98	(6.96)
	KEAH5	1	59.31	8.0	14.98	(6.96)
Max Day/High Wind	HEP1	1	59.51	12.2	19.15	(6.96)
	KEAH5	1	59.45	12.2	19.15	(6.96)
Max Day/Low Wind	HUHONUA	1	59.54	12.2	19.15	(6.96)
	KEAH4	2	58.44	15.2	37.39	(22.21)
Transfer Trip Stage 1 & 2						
Max Day/Low Wind	KEAH4	2	59.72	21.2	37.39	(16.16)
Transfer Trip Stage 1, Reduce CT 4						
Max Day/Low Wind	KEAH4	1	59.55	12.2	19.15	(6.96)

Table D-36. 2015 10 MW Legacy PV Results

Load/Wind Scenario	Unit trip	Stages Tripped	Min Freq Hz	Net Load/PV Tripped MW	Load Tripped MW	PV Tripped MW
Min Day/High Wind	APOLLO	2	58.39	5.2	29.2	(24.1)
	HUHONUA	2	58.37	5.2	29.2	(24.1)
Min Day/Low Wind	HUHONUA	2	58.36	5.2	29.2	(24.1)
	KEAH4	2	58.32	5.2	29.2	(24.1)
	KEAH5	2	58.31	5.2	29.2	(24.1)
Max Day/High Wind	HEP1	2	58.42	13.3	37.4	(24.1)
	KEAH4	2	58.42	13.3	37.4	(24.1)
	KEAH5	2	58.42	13.3	37.4	(24.1)
Max Day/Low Wind	APOLLO	2	58.45	13.3	37.4	(24.1)
	HUHONUA	2	58.38	13.3	37.4	(24.1)
	KEAH4	2	58.30	13.3	37.4	(24.1)
Transfer Trip Stage 1						
Min Day/High Wind	APOLLO	1	58.50	(1.7)	15.0	(16.7)
	HUHONUA	1	59.69	8.0	15.0	(7.0)
Min Day/Low Wind	HUHONUA	1	59.42	8.0	15.0	(7.0)
	KEAH4	1	59.33	8.0	15.0	(7.0)
	KEAH5	1	59.31	8.0	15.0	(7.0)
Max Day/High Wind	HEP1	1	59.51	12.2	19.2	(7.0)
	KEAH4	1	59.47	12.2	19.2	(7.0)
	KEAH5	1	59.45	12.2	19.2	(7.0)
Max Day/Low Wind	APOLLO	1	59.48	12.2	19.2	(7.0)
	HUHONUA	1	59.54	12.2	19.2	(7.0)
	KEAH4	2	58.40	13.3	37.4	(24.1)
Transfer Trip Stage 1 & 2						
Max Day/Low Wind	KEAH4	2	59.72	21.2	37.4	(16.2)
Transfer Trip Stage 1, Reduce CT 4						
Max Day/Low Wind	KEAH4	1	59.55	12.2	19.2	(7.0)

Table D-37. 2015 13 MW Legacy PV Results

Load/Wind Scenario	Unit trip	Stages Tripped	Min Freq Hz	Net Load/PV Tripped MW	Load Tripped MW	PV Tripped MW
Min Day/High Wind	APOLLO	2	58.47	4.9	30.3	(25.4)
	HUHONUA	2	58.45	4.9	30.3	(25.4)
Min Day/Low Wind	HUHONUA	2	58.47	4.9	30.3	(25.4)
Max Day/Low Wind	HUHONUA	2	58.45	12.0	37.4	(25.4)
	KEAH4	2	58.34	12.0	37.4	(25.4)
	KEAH5	2	58.33	12.0	37.4	(25.4)
Transfer Trip Stage 1						
Min Day/High Wind	APOLLO	1	58.76	(0.3)	15.5	(15.8)
	HUHONUA	1	59.71	7.2	15.5	(8.3)
Min Day/Low Wind	HUHONUA	1	59.49	7.2	15.5	(8.3)
Max Day/Low Wind	HUHONUA	1	59.47	10.8	19.2	(8.3)
	KEAH4	2	58.43	12.0	37.4	(25.4)
	KEAH5	2	58.42	12.0	37.4	(25.4)
Transfer Trip Stage 1 & 2						
Max Day/Low Wind	KEAH4	2	59.65	18.1	37.4	(19.3)
	KEAH5	2	59.65	18.1	37.4	(19.3)

Table D-38. 2016 10 MW Legacy PV Results

Load/Wind Scenario	Unit trip	Stages Tripped	Min Freq Hz	Net Load/PV Tripped MW	Load Tripped MW	PV Tripped MW
Min Day/High Wind	APOLLO	2	58.38	3.0	30.3	(27.3)
	HUHONUA	2	58.38	3.0	30.3	(27.3)
Min Day/Low Wind	HUHONUA	2	58.40	3.0	30.3	(27.3)
	KEAH4	2	58.42	3.0	30.3	(27.3)
	KEAH5	2	58.42	3.0	30.3	(27.3)
Max Day/High Wind	HUHONUA	2	58.45	10.1	37.4	(27.3)
	KEAH5	2	58.48	13.5	36.8	(23.3)
Max Day/Low Wind	HUHONUA	2	58.41	10.1	37.4	(27.3)
	KEAH4	2	58.24	10.1	37.4	(27.3)
	KEAH5	2	58.22	10.1	37.4	(27.3)
Transfer Trip Stage 1						
Min Day/High Wind	APOLLO	2	58.49	3.0	30.3	(27.3)
	HUHONUA	1	59.71	7.2	15.5	(8.3)
Min Day/Low Wind	HUHONUA	1	59.49	7.2	15.5	(8.3)
	KEAH4	1	59.45	7.2	15.5	(8.3)
	KEAH5	1	59.44	7.2	15.5	(8.3)
Max Day/High Wind	HUHONUA	1	59.67	10.8	19.2	(8.3)
	KEAH5	1	59.64	10.8	19.2	(8.3)
Max Day/Low Wind	HUHONUA	1	59.47	10.8	19.2	(8.3)
	KEAH4	2	58.35	10.1	37.4	(27.3)
	KEAH5	2	58.33	10.1	37.4	(27.3)
Transfer Trip Stage 1 & 2						
Min Day/High Wind	APOLLO	2	59.38	11.0	30.3	(19.3)
Max Day/Low Wind	KEAH4	2	59.65	18.1	37.4	(19.3)
	KEAH5	2	59.65	18.1	37.4	(19.3)

Table D-39. 2016 13 MW Legacy PV Results

E. Essential Grid Services

Grid services include generating capacity plus ancillary services, which are both essential to reliable system operation. Generating capacity is used to meet load demands; ancillary services supplement the generating capacity to help meet demand or correct frequency deviations that occur as a result of normal changes in load and generation, as well as the result of abnormal transient events. Ancillary services can occur in layers, with some taking longer to act than others. The system operator needs to designate which ancillary services are necessary for the system characteristics at the time.

Synchronous generation has traditionally provided generating capacity and ancillary services. Increasing amounts of variable generation, however, diminish the amount of dispatchable generation on the system and the ability of dispatchable generation to provide the needed ancillary services. In many cases, the variable generation resources do not provide the level of ancillary services required for the system's security. In addition, the potential loss of variable distributed generation (whether due to large ramping events or trips due to transient events) has become the largest contingency for which many of the ancillary services must be designed.

For these reasons, new generation resources must have the ability to also provide required ancillary services, or new systems that can provide the ancillary services must be added. Variable generation costs should include the cost of periodic testing and maintenance of their accompanying ancillary systems to ensure the reliability of the electric system. The variable generation protection and control devices should be tested and verified at installation, and tested and maintained periodically after that. Every device should be calibrated and tested at least every three years.

GRID SERVICES

Capacity

Capacity is the maximum reliable amount of electrical output available from a resource. Systems must be operated to ensure there is sufficient capacity online to meet demand in the near term. Systems must be planned and designed to ensure that there is adequate supply of capacity to meet future demands. For dispatchable generation, the capacity is the maximum power output of the generating unit[1]. For variable generation (such as wind or solar power), capacity in the near term is the minimum available amount of output expected in the next one to three hours. The capacity of controlled load in the near term is the minimum level of load under control during each of the four six-hour planning periods of a 24-hour day.

For planning capacity margins, the capacity contribution for variable generation is developed by examining the historical availability during the peak demand periods, to determine the amount of capacity which is very probable to be available in the peak period. Similarly, demand response could contribute to capacity if it is available during the peak period. To count as capacity, the generation does not have to be under automatic generation control (AGC) to reach its maximum rating. Unit control can be by AGC, by human intervention, or a combination, so long as the output is controllable and predictable.

Capacity does not have a response time requirement. However, as stated above, it must be reliably available for a period of time.

Generation capacity should be modeled and tested consistent with HI-Mod-0010 and HI-Mod-0025.[2] Controlled load capacity should be modeled and tested in accordance with capacity testing and modeling requirements for conventional generation capacity. Controlled load will need periodic review and exercising to confirm its stated capacity, as the load characteristics change over time.

1 Generators are designed higher than its prime mover's capability, therefore the generator's nameplate rating can sometimes be higher than what it actually produces.

2 HI-Mod-0010 is the proposed Hawaiian standard for modeling unit capacity used for system studies. HI-Mod-0025 is the proposed Hawaiian standard for testing unit capacity to confirm its model for use in electrical studies.

ANCILLARY SERVICES

Regulating Reserve

Regulating reserve is the amount of unloaded capacity of regulation resources that can be used to match system demand with generation resources and maintain normal frequency. Use of regulating reserve is governed by a command from Automatic Generation Control (AGC) to a change in system demand. A change in system demand results in a change in system frequency, and the AGC program will adjust the generating units under its control to return system frequency to the normal state. A regulation resource is a resource that immediately responds, without delay, to commands from AGC to predictably increase or decrease its generation output. Regulation resources must accurately and predictably respond to AGC commands throughout their range of operation.

Regulation resources can also include non-traditional resources such as controlled loads or storage, providing the necessary control capabilities and response for the AGC interface. Non-generation resources participating in regulation must be capable of sustaining the maximum increase or decrease for at least 30 minutes.

Regulating reserve is used to counter normal changes in load or variable generation. Changes in generation output or controlled loads must be completed within 2 seconds of the AGC command, and must be controllable by AGC to a resolution of 0.1 MW.

In our islanded power system, regulation resources are constantly used to balance load and generation to maintain a 60 Hz frequency reference. The number of controls to regulating resources is greater than larger systems, due to a combination of the impacts of the small system size, its isolation, and the amount of variable wind and solar generation on the systems whose variable output requires additional adjustments from regulating resources. As a result, it has been typical on the island systems that all online resources capable of participating in regulation are used for regulation.

If demand response or storage are used for regulation, the cost of modifying the AGC system to be able to utilize these non-traditional resources as a regulation resource should be included in valuation of these alternate resources. The implementation must include special considerations specific to non-generation resources, such as the need to adopt the regulation algorithms to consider that the limits of the storage or demand response (that is, the response cannot be sustained indefinitely, unlike a dispatchable generator), and to include the rotation of DR within the group to limit impact on DR resources of the same type.

Contingency Reserve

Each of the Companies' systems must be operated such that the system remains operable and the grid frequency can be quickly restored following a contingency situation wherein a generating or transmission resource on the island suddenly trips offline. This can be the largest single unit, the largest combination of dependent units (such as combined cycle units), or the loss of a single transmission line connecting a large generation unit to the system. The contingency reserve is the reserve designated by a system operator to meet these requirements.

Conventional generation, stored energy resources, curtailed variable generation, load shed or DR resources can provide contingency reserves.

Contingency reserves carried on generator resources, including storage, must respond automatically to changes in the system frequency, with a droop response determined by the system operator.

The island systems are unique in that all imbalances between supply and demand result in a change in system frequency. There are no interconnections to draw additional power from in the event of loss of generation. As a result, the island systems rely heavily upon instantaneous underfrequency load-shed to provide protection reserves and contingency reserves. If participating in the instantaneous protection, which may be used for contingency reserves or system protection, DR or load shed must be accurate to ± 0.02 Hz and ± 0.0167 cycles. The response time from frequency trigger to load removal can be no more than 7 cycles.

DR that cannot meet the 7-cycle requirement may be used for a time-delay, or the "kicker block" of under frequency load-shed. This block of load-shed is used for smaller increments of generation loss than the contingency reserves (set at a higher frequency set-point than the faster, instantaneous load-shed). Resources deployed for time-delay load-shed must be controllable within an accuracy of ± 0.02 Hz and ± 0.02 seconds, and have a response time from frequency trigger to load removal adjustable in increments of 0.5 seconds up to 30 seconds, to be considered for use as time delay load-shed.

To ensure consistent performance, DR controls and loads used for contingency reserve should be tested and certified annually. (See HI-Mod-012, HI-Mod-010, and HI-Mod-025, 26, 27.[3]) Annual costs for testing and certification should be included in the total cost for these provisions.

[3] HI-Mod-0012 is the proposed Hawaiian standard for modeling and reporting the dynamic response of system models and results of simulations using these models. HI-Mod-0260 is the proposed Hawaiian standard for verifying plant or excitation equipment used in system models. HI-MOD-0027 is the proposed Hawaiian standard for verifying the models for turbine/governor and frequency control functions.

Controllable load used in any other DR program cannot be included in the loads designated as contingency reserves. The impacts of any DR use on the instantaneous underfrequency load-shed schemes must be evaluated and incorporated into the design to ensure adequate system protection remains.

10-Minute Reserve

Off-line, quick-start resources can be used as 10-minute reserves provided they can be started and synchronized to the grid in 10 minutes or less. These resources may be used for restoring regulation or contingency reserves.

When conditions warrant, a system operator starts the 10-minute reserve resource remotely, and automatically synchronizes it to the power system. The system operator then either loads the resource to a predetermined level, or places it under AGC control, either of which must be completed within 10 minutes. The 10-minute reserve must be able to provide the declared output capability for a minimum of two hours.

The resource can be any resource with a known output capability. Resources can include generators, storage, and controllable loads. A system operator must be able to control these resources to restore regulation or contingency reserves.

30-Minute Reserve

Off-line, 30-minute reserve resources shall be resources that can be operated during normal load and generation conditions, and can be started and synchronized to the grid in 30 minutes or less. They can be counted as capacity resources to meet expected load and demand, or to restore contingency reserves.

When conditions warrant, a system operator starts the resource remotely, synchronizes it, and (if participating in regulating reserves) places it under AGC control within 30 minutes; when it must then be able to serve the capacity for at least three hours.

The 30-minute reserve resource can be any resource with a known capacity. A system operator must be able to control these load resources to restore contingency or regulation reserves.

Long Lead-Time Reserve

Resources that take longer than 30 minutes to be started, synchronized, and placed under AGC control (if participating in regulating reserves) are considered long lead-time reserves. They can be operated during normal load and generation conditions. These resources may be used as capacity resources to meet expected load and demand, and for restoring contingency reserves.

Long lead-time reserves can include any resource with a known capacity. System operators must be able to control these load resources to restore contingency reserves.

Long-lead time resources can be used to meet forecast peak demand, in addition to restoring contingency reserves or the replacement of fast-start reserves. Long-lead time reserves must be able to serve the capacity for at least three hours.

Black Start Resource

A black start resource is a generating unit and its associated equipment that can be started without support from the power system, or is designed to remain energized without connection to the remainder of the power system. A black start resource needs to be able to energize a bus, meeting a system operator's restoration plan needs for real and reactive power capability, frequency, and voltage control. It must also be included in the transmission operator's restoration plan.

A black start resource must be capable of starting within 10 minutes. The starting sequence can be manual or automatic.

Primary Frequency Response

Primary frequency response is a generation resource's automatic response to an increase or decrease in frequency. The primary frequency response is the result of governor control, not control by AGC or frequency triggers, and must be sustainable. Unless controlled by a governor or droop response device, controlled load cannot provide primary frequency control.

The resource must immediately alter its output in direct proportion to the change in frequency, to counter the change in frequency. The response is determined by the design setting, which is specified by the system operator as a droop response from 1 to 5 percent. The response must be measurable within 10 seconds of the change in frequency. Under certain conditions, a certain generator resource may be placed on zero droop (also called isochronous control), such as under disturbance and restoration. Under these conditions, the isochronous generator will control system frequency instead of AGC.

Primary frequency response of a device is subject to the limitations of equipment. Equipment that is at its maximum operating output is not able to increase output in response to low frequency, but will still decrease its output in response to increasing frequency. Any generator at its maximum output, or a variable wind generator producing the maximum output for the available wind energy, may, if designed to have a frequency response, provide downward response to high frequency, but will not be able to increase output in response to low frequency. Curtailed variable generation or conventional generation operating below its maximum limit and above its minimum limit can contribute both upward and downward primary frequency response. Based on the design of its system, energy storage systems can also provide primary frequency response.

Primary frequency response cannot be withdrawn if frequency is within the bandwidth of a reportable disturbance as defined in BAL-HI-002. The primary frequency response should replace the inertia or fast frequency response of the system without a drop in system frequency.

Inertial or Fast Frequency Response

Inertial or fast frequency response is a local response to a change in frequency, reducing its rate of change. The response is immediate (measured in milliseconds), continuous, and proportional to the change in frequency, and does not rely on governor controls. The response is available even if the resource is also being used for other services (such as regulation or ramping). This response is short-lived, lasting not more than two to three seconds.

Inertial response relies on the rotating mass of a conventional generator. It can also be supplied by flywheels. Fast frequency response can be supplied by battery storage. If the inertia or fast response reserves are supplied from a resource that cannot sustain the load, primary or secondary resources must be available to take over without a drop in system frequency.

Secondary Frequency Control

Secondary (or supplemental) frequency control is provided by resources in response to AGC to correct a change in frequency, using both the regulating and contingency reserves. Secondary frequency response can be provided by conventional generation, load control, or variable generation, all of which must be under AGC control. If AGC is disabled, such as during system restoration, secondary frequency control will be provided by manual operation of resources to maintain the isochronous generator within its lower and upper limits. The response requirements for secondary control are the same as for participation in regulating reserves.

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F. Modeling Assumptions Data

The Hawaiian Electric Companies created this PSIP based, in parts, on a realization of the current state of the electric systems in Hawaiʻi, forecast conditions, and reasonable assumptions regarding technology readiness, availability, performance, applicability, and costs. As a result, this plan presents a reasonable and viable path into the future for the evolution of our power systems. We have attempted to document and be fully transparent about the assumptions and methodologies utilized to develop this plan. We recognize, however, that over time these forecasts and assumptions may or may not prove to be accurate or representative, and that the plan would need to be updated to reflect changes. As we move forward, we will continually evaluate the impacts of any changes to our material assumptions, seek to improve the planning methodologies, and evaluate and revise the plan to best meet the needs of our customers.

This appendix summarizes the assumptions utilized to perform the PSIP analyses.

Tables

UTILITY COST OF CAPITAL AND FINANCIAL ASSUMPTIONS

The Hawaiian Electric Companies finance their investments through two main sources of capital: debt (borrowed money) or equity (invested money). In both cases, we pay a certain rate of return for the use of this money. This rate of return is our *Cost of Capital*.

Table F-1 lists the various sources of capital, their weight (percent of the entire capital portfolio), and their individual rates of return. Composite percentages for costs of capital are presented under the table.

Capital Source	Weight	Rate
Short Term Debt	3.0%	4.0%
Long Term Debt (Taxable Debt)	39.0%	7.0%
Hybrids	0.0%	6.5%
Preferred Stock	1.0%	6.5%
Common Stock	57.0%	11.0%

Composite Weighted Average 9.185%
After-Tax Composite Weighted Average 8.076%

Table F-1. Utility Cost of Capital

FUEL SUPPLY AND PRICES FORECASTS

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. Maui Electric may burn the following different types of fuels during the study period on Hawaiʻi Island:

- *No.2 Diesel*
- *Medium Sulfur Fuel Oil (MSFO)*, and also referred to as Industrial Fuel Oil (IFO) or Bunker Fuel Oil; is less 2% sulfur content.
- *Low Sulfur Industrial Fuel Oil (LSIFO)* is used when a fuel with lower sulfur content than MSFO is needed. It is about 0.75% sulfur content.
- *Ultra Low Sulfur Diesel (ULSD)* that is as low as 0.0015% sulfur content.
- *Biodiesel*
- *Petroleum Naphtha* is a desulfurized, high-octane fuel derived from crude oil.
- *Liquefied Natural Gas (LNG)* is a natural gas (a fossil fuel) that has been converted to a liquid, which sharply decreases volume and eases transportation and storage.

How the Fuel Price Forecasts Were Derived

Petroleum-Based Diesel Fuels

In general, we derived petroleum-based diesel fuels 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 U.S. Energy Information Administration (EIA) forecast data for *Imported Crude Oil* and *GDP Chain-Type Price Index* from the 2014 Annual Energy Outlook (AEO2014) 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.

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 been found for biodiesel, although EIA might provide one in the future. In lieu of such a source, we used the Food and Agricultural Policy Research Institute at Iowa State University (FAPRI) to create a reference forecast, which we then scaled on the EIA Petroleum forecasts to create a low and high biodiesel forecast.

Liquefied Natural Gas (LNG)

We do not have historical purchase data for LNG in Hawai'i. For purposes of this PSIP analyses, LNG pricing (delivered to the power generation facilities) were developed as described in Appendix I: LNG to Hawai'i.

Hawai'i Electric Light Fuel Price Forecasts

$/MMBtu	Fuel Price Forecasts						
Year	*No.2 Diesel*	*MSFO*	*LSIFO*	*ULSD*	*Biodiesel*	*Naphtha*	*LNG*
2014	$22.73	$16.01	$18.48	$23.37	$34.00	$23.40	n/a
2015	$22.72	$15.97	$18.56	$23.36	$30.52	$23.41	$16.82
2016	$22.28	$15.59	$19.06	$22.91	$30.71	$23.03	$17.63
2017	$22.26	$15.55	$19.74	$22.89	$31.45	$23.05	$18.29
2018	$22.74	$15.90	$20.46	$23.39	$32.15	$23.53	$19.14
2019	$23.51	$16.48	$21.21	$24.18	$32.18	$24.29	$19.37
2020	$24.38	$17.13	$22.00	$25.07	$32.24	$25.15	$19.42
2021	$25.36	$17.86	$22.84	$26.07	$32.48	$26.10	$20.19
2022	$26.37	$18.62	$23.72	$27.11	$32.88	$27.09	$20.81
2023	$27.45	$19.43	$24.65	$28.21	$33.01	$28.14	$21.42
2024	$28.52	$20.24	$25.60	$29.31	$33.51	$29.19	$22.09
2025	$29.57	$21.03	$26.60	$30.39	$33.82	$30.22	$22.71
2026	$30.57	$21.78	$27.63	$31.42	$34.13	$31.20	$23.36
2027	$31.72	$22.65	$28.71	$32.60	$34.44	$32.32	$24.04
2028	$32.80	$23.45	$29.83	$33.70	$34.75	$33.37	$24.70
2029	$33.93	$24.30	$31.01	$34.86	$35.06	$34.49	$25.49
2030	$35.01	$25.10	$32.23	$35.97	$35.38	$35.55	$26.43

Table F-2. Fuel Price Forecasts

SALES AND PEAK FORECASTS

Sales and net peak forecasts were developed with and without the effects of Dynamic Pricing. As described in the *Integrated Demand Response Portfolio Plan (IDRPP)*[1] Dynamic Pricing is a demand response program that incent customers (on a voluntary basis) to change their energy use behavior, resulting is increased load demand during certain periods of the day and decreased net peak demand.

Sales Forecasts (without Dynamic Pricing Adjustments)

Year	Load without DG PV		Total DG PV (Uncurtailed)		Sales with DG PV
	Net Generation: GWh (a)	*Sales: Customer GWh (b)*	*Net GWh (c)*	*Customer GWh (d)*	*Customer GWh (b – d)*
2015	1,250.0	1,157.4	100.0	92.6	1,064.8
2016	1,269.8	1,170.3	113.9	104.9	1,065.3
2017	1,266.4	1,180.1	125.1	116.6	1,063.5
2018	1,282.5	1,195.1	129.9	121.1	1,074.0
2019	1,294.8	1,206.6	134.4	125.2	1,081.3
2020	1,306.4	1,217.4	139.1	129.7	1,087.7
2021	1,312.1	1,222.8	142.4	132.7	1,090.1
2022	1,319.8	1,229.9	145.9	136.0	1,093.9
2023	1,325.7	1,235.4	149.4	139.2	1,096.1
2024	1,335.4	1,244.4	153.2	142.8	1,101.6
2025	1,336.4	1,245.4	156.1	145.5	1,099.9
2026	1,338.2	1,247.0	159.3	148.4	1,098.6
2027	1,338.2	1,247.1	162.3	151.2	1,095.8
2028	1,336.5	1,245.4	165.7	154.4	1,091.0
2029	1,324.5	1,234.3	168.0	156.6	1,077.7
2030	1,313.8	1,224.3	170.7	159.1	1,065.2

Loss Factor: 7.40% in 2015, 7.84% in 2016, 6.81% in 2017 onward

Table F-3. Sales Forecasts (without Dynamic Pricing Adjustments)

[1] The IDRPP was filed on July 28, 2014.

Sales Forecasts (with Dynamic Pricing Adjustments)

Year	Load without DG PV		Total DG PV (Uncurtailed)		Sales with DG PV
	Net Generation: GWh (a)	*Sales: Customer GWh (b)*	*Net GWh (c)*	*Customer GWh (d)*	*Customer GWh (b – d)*
2015	1,250.0	1,157.5	100.0	92.6	1,064.8
2016	1,269.6	1,170.1	113.9	104.9	1,065.2
2017	1,263.0	1,176.9	125.1	116.6	1,060.4
2018	1,279.0	1,191.9	129.9	121.1	1,070.8
2019	1,291.3	1,203.3	134.4	125.2	1,078.1
2020	1,302.8	1,214.0	139.1	129.7	1,084.4
2021	1,308.5	1,219.4	142.4	132.7	1,086.7
2022	1,316.3	1,226.6	145.9	136.0	1,090.6
2023	1,322.1	1,232.0	149.4	139.2	1,092.8
2024	1,331.7	1,241.0	153.2	142.8	1,098.2
2025	1,332.8	1,242.0	156.1	145.5	1,096.5
2026	1,334.6	1,243.6	159.3	148.4	1,095.2
2027	1,334.6	1,243.7	162.3	151.2	1,092.4
2028	1,332.9	1,242.1	165.7	154.4	1,087.7
2029	1,320.9	1,230.9	168.0	156.6	1,074.3
2030	1,310.2	1,221.0	170.7	159.1	1,061.9

Table F-4. Sales Forecasts (with Dynamic Pricing Adjustments)

Net Peak Forecasts

Year	Net Peak (w/o DG PV + w/o Dynamic Pricing)	Net Peak (w/o DG PV + w/ Dynamic Pricing)	Total DG PV)
	MW	*MW*	*MW*
2015	189.8	189.8	64.8
2016	188.0	188.7	77.8
2017	182.2	189.0	85.7
2018	184.2	191.1	88.6
2019	186.0	192.9	91.4
2020	187.4	194.3	94.1
2021	188.3	195.2	96.3
2022	189.7	196.9	98.5
2023	190.4	197.4	100.6
2024	190.7	197.7	102.7
2025	191.6	198.6	104.7
2026	190.4	197.4	106.6
2027	189.8	196.1	108.5
2028	190.1	194.9	110.3
2029	187.5	193.7	112.0
2030	186.3	192.4	113.7

Table F-5. Net Peak Forecasts

DEMAND RESPONSE

Demand Response Programs

The *Integrated Demand Response Portfolio Plan*[2] introduced seven categories of programs.

Residential and Small Business Direct Load Control Program (RBDLC). This new RBDLC program continues and expands upon the existing RDLC and Small Business Direct Load Control (SBDLC) programs. RBDLC enables new and existing single-family, multi-family, and master metered residential customers, in addition to small businesses, to participate in an interruptible load program for electric water heaters, air conditioning, and other specific end uses.

Residential and Small Business Flexible Program. This new program enables residential and small business customers with targeted devices (such as controllable grid-interactive water heaters) to meet ancillary service requirements by providing adjustable load control and thermal energy storage features over various timeframes.

Commercial & Industrial Direct Load Control Program (CIDLC). The updated CIDLC program allows commercial and industrial customers to help shift load, usually during peak periods, by allowing their central air conditioning, electric water heaters, and other applicable appliances to be remotely cycled or disconnected.

Commercial & Industrial Flexible Program. This new program enables commercial and industrial customers with targeted devices (such as air conditioning, ventilation, refrigeration, water heating, and lighting) to meet ancillary service requirements by providing adjustable load control and/or thermal energy storage features over differing timeframes.

Commercial & Industrial Pumping Program. The Commercial & Industrial Pumping program enables county and privately owned water facilities with pumping loads and water storage capabilities to be dynamically controlled. This will be accomplished by using variable frequency drives and emergency standby generation to adjust power demand and supply at the water facilities, and better balance supply and demand of power system loads.

Customer Firm Generation Program. Commercial and industrial customers who participate in this program allow system operators to dispatch their on-site standby generators to help meet power system load demand. Monitoring equipment on the

[2] *ibid.*

standby generators tracks the usage of program participation, testing, and assures environmental permit compliance.

Dynamic & Critical Peak Pricing program. This program enables load shifting to "smooth" the daily system load profiles based on demand and price.

Cost of DR Programs

Several grid services foretell the cost of the demand response programs. The avoided cost for a grid service is the cost of an alternative resource (energy storage or a generator) providing the equivalent service. Avoided cost could be based on several factors, including installed capacity costs, fuel costs, and cost of alternatives, each of which depends on the current state of the system. Potential avoided cost calculations include:

Capacity: The cost of new capacity deferral.

Regulating Reserve: The cost of a frequency support energy storage device, or the savings from reduced regulating reserve requirements, as calculated using a production cost model.

Contingency Reserve:. For O'ahu, the fuel cost savings resulting from a reduction in the contingency reserve requirement from thermal generation commensurate with the DR resources assumed to meet the contingency reserve requirements, as calculated using a production cost model. For Maui and Hawai'i, this would offset under-frequency load shedding, which potentially provides a customer benefit but not a readily evaluated economic benefit.

Non-AGC Ramping: The fuel cost and maintenance savings resulting from deferring the start of units to compensate for variable energy down ramps.

Non-Spinning Reserve: The cost of maintaining existing resources that currently meet non-spinning reserves (small diesel units).

Advanced Energy Delivery: The production cost savings incurred by shifting demand, as compared to production costs if demand were not shifted.

All of the above avoided costs are offset by the program costs and reduced sales. Where a resource or program can meet two or more grid service requirements, although not simultaneously, the avoided cost is determined by the most economic use. The maximum price paid for a DR program would be the difference between the avoided cost and the program's operational cost. At the maximum price, the overall rate impact to customers would be economically neutral.

Demand Response Grid Service Requirements and MW

Grid Service	Residential and Small Business Direct Load Control				Residential and Small Business Flexible	
	Capacity	*Contingency Reserve*	*Non-AGC Ramping*	*Non-Spinning Reserve*	*Regulating Reserve*	*Accelerated Energy Delivery*
Frequency	Unlimited	Unlimited	Unlimited	Unlimited	Continuous	Continuous
Event Length	1 hour	1 hour	1 hour	1 hour	Minutes	Minutes
Event Cost	None	None	None	None	None	None
Year	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*
2014	0.0	0.0	0.0	0.0	0.0	0.0
2015	0.3	0.0	0.3	0.3	0.2	0.1
2016	1.4	0.0	1.4	1.4	0.3	0.2
2017	2.6	0.0	2.6	2.6	0.5	0.3
2018	3.7	0.0	3.7	3.7	0.7	0.4
2019	4.9	0.0	4.9	4.9	0.9	0.5
2020	6.0	0.0	6.0	6.0	1.1	0.6
2021	6.0	0.0	6.0	6.0	1.2	0.7
2022	6.0	0.0	6.0	6.0	1.4	0.7
2023	6.0	0.0	6.0	6.0	1.4	0.7
2024	6.0	0.0	6.0	6.0	1.4	0.7
2025	6.0	0.0	6.0	6.0	1.4	0.7
2026	6.0	0.0	6.0	6.0	1.4	0.7
2027	6.0	0.0	6.0	6.0	1.4	0.7
2028	6.0	0.0	6.0	6.0	1.4	0.7
2029	6.0	0.0	6.0	6.0	1.4	0.7
2030	6.0	0.0	6.0	6.0	1.4	0.7

Table F-6. Demand Response Program Grid Service Requirements and MW Benefits (1 of 2)

Grid Service	Commercial & Industrial Direct Load Control		Commercial & Industrial Flexible		Commercial & Industrial Pumping		Customer Firm Generation
	Capacity	*Contingency Reserve*	*Regulating Reserve*	*Non-AGC Ramping*	*Regulating Reserve*	*Non-AGC Ramping*	*Capacity*
Frequency	300 hours per year	300 hours per year	Continuous	Continuous	Continuous	Continuous	100 hours per year
Event Length	4 hours maximum	4 hours maximum	Minutes	Minutes	Minutes	Minutes	4 hours maximum
Event Cost	50¢/kWh	50¢/kWh	None	None	None	None	50¢/kWh
Year	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*
2014	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2015	0.2	0.0	0.1	0.2	0.0	0.0	0.0
2016	0.6	0.0	0.1	0.3	0.0	0.0	3.0
2017	1.0	0.0	0.2	0.5	0.1	0.1	3.0
2018	1.4	0.0	0.2	0.7	0.1	0.1	3.0
2019	1.8	0.0	0.3	0.9	0.1	0.1	3.0
2020	2.2	0.0	0.3	1.1	0.1	0.1	3.0
2021	2.2	0.0	0.4	1.3	0.2	0.2	3.0
2022	2.2	0.0	0.4	1.4	0.2	0.2	3.0
2023	2.2	0.0	0.4	1.4	0.2	0.2	3.0
2024	2.2	0.0	0.4	1.4	0.2	0.2	3.0
2025	2.2	0.0	0.4	1.4	0.2	0.2	3.0
2026	2.2	0.0	0.4	1.4	0.2	0.2	3.0
2027	2.2	0.0	0.4	1.4	0.2	0.2	3.0
2028	2.2	0.0	0.4	1.4	0.2	0.2	3.0
2029	2.2	0.0	0.4	1.4	0.2	0.2	3.0
2030	2.2	0.0	0.4	1.4	0.2	0.2	3.0

Table F-7. Demand Response Program Grid Service Requirements and MW (2 of 2)

RESOURCE CAPITAL COSTS[3]

The calculations for the capital cost for different resources used in the PSIP modeling analyses are shown in Tables F-46 through F-54.

The overall cost escalation rate used throughout our analyses is 1.83%.

Table Legend

Column Heading	Explanation
NREL Capital Cost, 2009 $, $/kW	The starting basis for capital costs used in the analyses unless noted otherwise
B&V Hawai'i Capital Cost, 2009 $, $/kW	The starting basis for capital cost of the ICE (<100 MW)
BCG Capital Cost, 2009 $, $/kW	The starting basis for capital cost of the ICE (>100 MW)
EIA Capital Cost, 2009 $, $/kW	The starting basis for capital cost of the Waste-to-Energy resource
Capital Cost, Nominal $, $/kW	An escalated capital cost of the resource from 2009 dollars up to the year of installation
EIA Adjustment Factor	A location specific cost adjustment factor for Hawai'i
Utility Adjustment Factor	A technology specific cost adjustment factor
Adjusted Capital Cost, Nominal $, $/kW	An escalated capital cost of the resource that reflects any cost adjustment factors
NREL Fixed O&M, 2009 $, $/kW-year	The starting basis for fixed O&M used in the analyses
Fixed O&M, Nominal $, $/kW	An escalated fixed O&M cost of the resource from 2009 dollars up to the year of installation
NREL Variable O&M, 2009 $, $/MWh	The starting basis for variable O&M used in the analyses
Variable O&M, Nominal $, $/MWh	An escalated variable O&M cost of the resource from 2009 dollars up to the year of installation

Table F-8. Resource Capital Cost Table Legend

3 Calculations were based on *Cost and Performance Data for Power Generation Technologies*, prepared for the National Renewable Energy Laboratory (NREL), Black & Veatch, February 2012.

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Simple Cycle Large (40–100 MW) Aeroderivative Combustion Turbine

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$651.00	$726.04	51.5%	1.46	$1,608.29	$5.26	$5.87	$29.90	$33.35
2020	$651.00	$795.14	51.5%	1.46	$1,761.36	$5.26	$6.42	$29.90	$36.52
2025	$651.00	$870.81	51.5%	1.46	$1,928.99	$5.26	$7.04	$29.90	$40.00
2030	$651.00	$953.69	51.5%	1.46	$2,112.58	$5.26	$7.71	$29.90	$43.80

Table F-9. Simple Cycle Large (40–100 MW) Aeroderivative Combustion Turbine

Simple Cycle Small (<40 MW) Aeroderivative Combustion Turbine

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$651.00	$726.04	51.5%	1.77	$1,945.73	$5.26	$5.87	$29.90	$33.35
2020	$651.00	$795.14	51.5%	1.77	$2,130.91	$5.26	$6.42	$29.90	$36.52
2025	$651.00	$870.81	51.5%	1.77	$2,333.71	$5.26	$7.04	$29.90	$40.00
2030	$651.00	$953.69	51.5%	1.77	$2,555.82	$5.26	$7.71	$29.90	$43.80

Table F-10. Simple Cycle Small (<40 MW) Aeroderivative Combustion Turbine

Internal Combustion (<100 MW) Engine

Year Installed	B&V Hawai'i Capital Cost, 2012 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$2,810.00	$2,967.54	0.0%	1.00	$2,967.54	$10.14	$11.31	$11.74	$13.09
2020	$2,810.00	$3,249.96	0.0%	1.00	$3,249.96	$10.14	$12.39	$11.74	$14.34
2025	$2,810.00	$3,559.27	0.0%	1.00	$3,559.27	$10.14	$13.56	$11.74	$15.70
2030	$2,810.00	$3,898.02	0.0%	1.00	$3,898.02	$10.14	$14.85	$11.74	$17.20

Table F-11. Internal Combustion (<100 MW) Engine

Internal Combustion (>100 MW) Engine

Year Installed	BCG Capital Cost, 2012 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$1,352.00	$1,427.80	0.0%	1.20	$1,713.36	$10.14	$11.31	$11.74	$13.09
2020	$1,352.00	$1,563.68	0.0%	1.20	$1,876.42	$10.14	$12.39	$11.74	$14.34
2025	$1,352.00	$1,712.50	0.0%	1.20	$2,055.01	$10.14	$13.56	$11.74	$15.70
2030	$1,352.00	$1,875.49	0.0%	1.20	$2,250.59	$10.14	$14.85	$11.74	$17.20

Table F-12. Internal Combustion (>100 MW) Engine

Residential Photovoltaics

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$4,340.00	$4,840.26	0.0%	1.00	$4,840.26	$48.00	$53.53	$0.00	$0.00
2020	$3,750.00	$4,580.29	0.0%	1.00	$4,580.29	$45.00	$54.96	$0.00	$0.00
2025	$3,460.00	$4,628.29	0.0%	1.00	$4,628.29	$43.00	$57.52	$0.00	$0.00
2030	$3,290.00	$4,819.74	0.0%	1.00	$4,819.74	$41.00	$60.06	$0.00	$0.00

Table F-13. Residential Photovoltaics

Utility Scale Photovoltaics (Fixed Tilt)

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$2,550.00	$2,843.93	0.0%	0.75	$2,132.95	$48.00	$53.53	$0.00	$0.00
2020	$2,410.00	$2,943.60	0.0%	0.75	$2,207.70	$45.00	$54.96	$0.00	$0.00
2025	$2,280.00	$3,049.86	0.0%	0.75	$2,287.39	$43.00	$57.52	$0.00	$0.00
2030	$2,180.00	$3,193.62	0.0%	0.75	$2,395.22	$41.00	$60.06	$0.00	$0.00

Table F-14. Utility Scale Photovoltaics (Fixed Tilt)

Geothermal, Non-Dispatchable

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$5,940.00	$6,624.69	27.2%	1.00	$8,426.61	$36.00	$40.15	$31.00	$34.57
2020	$5,940.00	$7,255.18	27.2%	1.00	$9,228.59	$36.00	$43.97	$31.00	$37.86
2025	$5,940.00	$7,945.68	27.2%	1.00	$10,106.91	$36.00	$48.16	$31.00	$41.47
2030	$5,940.00	$8,701.89	27.2%	1.00	$11,068.81	$36.00	$52.74	$31.00	$45.41

Table F-15. Geothermal, Non-Dispatchable

Geothermal, Fully Dispatchable

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$6,065.00	$6,764.10	27.2%	1.00	$8,603.94	$36.00	$40.15	$31.00	$34.57
2020	$6,065.00	$7,407.86	27.2%	1.00	$9,422.80	$36.00	$43.97	$31.00	$37.86
2025	$6,065.00	$8,112.89	27.2%	1.00	$10,319.59	$36.00	$48.16	$31.00	$41.47
2030	$6,065.00	$8,885.02	27.2%	1.00	$11,301.74	$36.00	$52.74	$31.00	$45.41

Table F-16. Geothermal, Fully Dispatchable

Combined Cycle Turbine

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$1,230.00	$1,371.78	53.1%	1.21	$2,533.86	$6.31	$7.04	$3.67	$4.09
2020	$1,230.00	$1,502.34	53.1%	1.21	$2,775.02	$6.31	$7.71	$3.67	$4.48
2025	$1,230.00	$1,645.32	53.1%	1.21	$3,039.13	$6.31	$8.44	$3.67	$4.91
2030	$1,230.00	$1,801.91	53.1%	1.21	$3,328.37	$6.31	$9.24	$3.67	$5.38

Table F-17. Combined Cycle Turbine

Run-of-River Hydroelectric

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$3,500.00	$3,903.44	19.1%	1.35	$6,276.14	$15.00	$16.73	$24.00	$26.77
2020	$3,500.00	$4,274.94	19.1%	1.35	$6,873.46	$15.00	$18.32	$24.00	$29.31
2025	$3,500.00	$4,681.80	19.1%	1.35	$7,527.63	$15.00	$20.06	$24.00	$32.10
2030	$3,500.00	$5,127.38	19.1%	1.35	$8,244.06	$15.00	$21.97	$24.00	$35.16

Table F-18. Run-of-River Hydroelectric

Wind, Onshore

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$1,980.00	$2,208.23	30.1%	1.00	$2,872.91	$60.00	$66.92	$0.00	$0.00
2020	$1,980.00	$2,418.39	30.1%	1.00	$3,146.33	$60.00	$73.28	$0.00	$0.00
2025	$1,980.00	$2,648.56	30.1%	1.00	$3,445.78	$60.00	$80.26	$0.00	$0.00
2030	$1,980.00	$2,900.63	30.1%	1.00	$3,773.72	$60.00	$87.90	$0.00	$0.00

Table F-19. Wind, Onshore

Wind, Offshore (Floating Platform)

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	Not Commercial	Not Commercial	0.0%	Not Commercial	$0.00	$0.00	$0.00	$0.00	Not Commercial
2020	$4,200.00	$5,129.93	30.1%	1.00	$6,674.04	$130.00	$158.78	$0.00	$0.00
2025	$4,090.00	$5,471.02	30.1%	1.00	$7,117.79	$130.00	$173.90	$0.00	$0.00
2030	$3,990.00	$5,845.21	30.1%	1.00	$7,604.62	$130.00	$190.45	$0.00	$0.00

Table F-20. Wind, Offshore (Floating Platform)

Waste-to-Energy

Year Installed	EIA Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$8,312.00	$8,777.99	19.6%	1.00	$10,498.48	$392.82	$414.84	$8.75	$9.24
2020	$8,312.00	$9,613.42	19.6%	1.00	$11,497.65	$392.82	$454.32	$8.75	$10.12
2025	$8,312.00	$10,528.36	19.6%	1.00	$12,591.91	$392.82	$497.56	$8.75	$11.08
2030	$8,312.00	$11,530.37	19.6%	1.00	$13,790.32	$392.82	$544.92	$8.75	$12.14

Table F-21. Waste-to-Energy

Biomass Steam

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$3,830.00	$4,271.48	53.6%	1.00	$6,560.99	$95.00	$105.95	$15.00	$16.73
2020	$3,830.00	$4,678.01	53.6%	1.00	$7,185.42	$95.00	$116.03	$15.00	$18.32
2025	$3,830.00	$5,123.23	53.6%	1.00	$7,869.27	$95.00	$127.08	$15.00	$20.06
2030	$3,830.00	$5,610.82	53.6%	1.00	$8,618.22	$95.00	$139.17	$15.00	$21.97

Table F-22. Biomass Steam

Ocean Wave

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$9,240.00	$10,305.08	13.8%	1.00	$11,727.18	$474.00	$528.64	$0.00	$0.00
2020	$6,960.00	$8,501.02	13.8%	1.00	$9,674.16	$357.00	$436.04	$0.00	$0.00
2025	$5,700.00	$7,624.64	13.8%	1.00	$8,676.84	$292.00	$390.60	$0.00	$0.00
2030	$4,730.00	$6,929.29	13.8%	1.00	$7,885.53	$243.00	$355.99	$0.00	$0.00

Table F-23. Ocean Wave

G. Generation Resources

Electricity is typically produced through a turbine-generator process. The turbine rotates and drives a shaft in the generator to create electrical current.

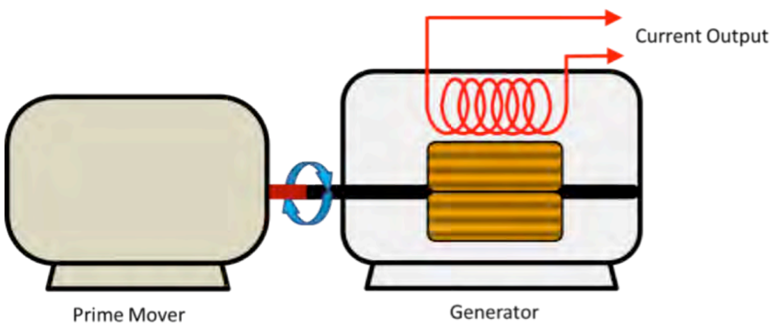

Figure G-1. Turbine-Generator Process

Turbines can be powered by different variable and firm sources. Variable energy is unpredictable because its energy source cannot be scheduled nor can it be controlled. Firm energy can be predicted, scheduled, dispatched, and controlled.

VARIABLE RNEWABLE ENERGY RESOURCES

Several variable renewable energy resources were considered in our PSIP analysis, all of which are currently in our generation mix. This type of energy is variable because its primary energy sources (such as wind, sun, and water) cannot be predicted.

The capacity value (essentially the percent of its "nameplate" generating amount that is available to the grid) of variable renewable energy varies by each resource, and is typically a small percentage of the nameplate value or zero. In addition, because the generation from variable renewable energy cannot be scheduled, it cannot be dispatched; in other words, it cannot be used to help regulate the balance between supply and demand.

Wind

Wind energy generation is the conversion of the wind's kinetic energy into electricity. Wind generating facilities are best located where wind is persistently steady. On Hawai'i with its terrain of hills, valleys, and ridges, variations in siting can have profound effects on the strength and quantity of wind currents.

As the wind turns a wind turbine's blades, the main shaft in the turbine rotates which in turn drives a generator (situated in the nacelle) to produce electricity. The annual capacity factor[1] of wind is generally about 25% at locations throughout Hawai'i, although it can attain a capacity factor of more than 50%.

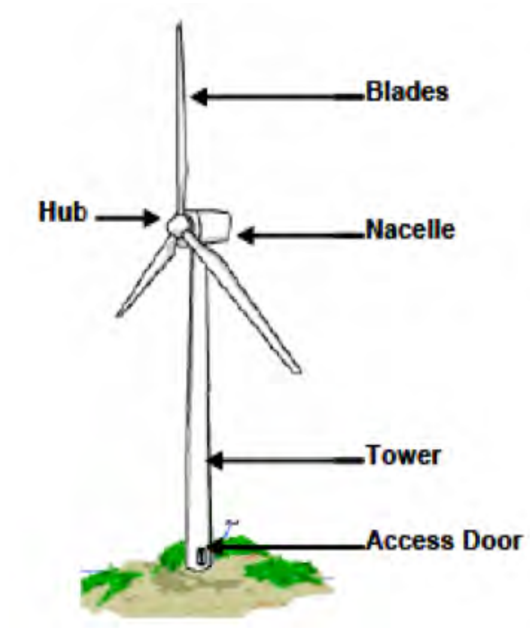

Figure G-2. Wind Turbine and Tower

A wind turbine shuts down when the wind is either too slow or too fast. The size of the wind turbine is generally in direct proportion to how much electricity can be generated. Larger wind turbines generate more power, while smaller turbines generate less. Thus, wind is a variable, non-dispatchable energy source.

[1] The Annual Capacity Factor, expressed in percent, is the amount of energy produced in a year compared to the amount of energy potentially produced by the facility if it was operated at 100% of its rated capacity for 100% of the time in the year.

Solar Photovoltaics

Solar photovoltaic energy is generated from its cells, and not by turning a turbine. Photovoltaic (PV) cells are made of semiconductors (such as silicon). When light strikes the cell, a certain portion of it is absorbed within the semiconductor material. The energy of the absorbed light is transferred to the semiconductor. The energy knocks electrons loose, allowing them to flow freely. This flow of electrons is a current, and by placing metal contacts on the top and bottom of the cell, this electric current can be drawn off for external use. The most common solar cell material is crystalline silicon, but newer materials for making solar cells include thin-film materials.

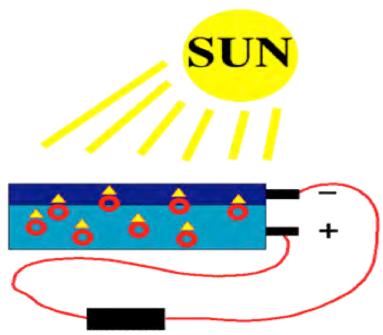

Figure G-3. Schematic of a Photovoltaic (PV) Cell and an Array of PV Panels

Solar PV is a variable renewable energy resource that cannot be scheduled and dispatched. Its annual capacity factor hovers between 18% to 22%. Solar PV only generates power when the sun is out and not blocked by clouds. On cloudless days, solar power gradually increases as the sun rises in the morning, peaks around 2 PM, and then gradually decreases until the sun sets. If at any point during the day a cloud blocks the sun, power output drops suddenly only to jump back up when the cloud passes. Thus, solar PV power generation can be erratic.

While solar PV systems can be made a few different ways, the most predominant is framed panels (as shown in Figure G-3). These panels consist of PV cells packaged as modules and framed into panels using aluminum framing, wiring, and glass enclosures. Multiple panels can be assembled into larger systems as arrays.

Distributed Solar Generation (DG-PV). These arrays can be installed on building rooftops, typically in a fixed direction as illustrated in Figure G-4. This rooftop solar is referred to as distributed generation because of the numerous small PV systems installed in many different locations distributed throughout the grid. These rooftop PV panels produce direct current (DC) electricity fed to an inverter which converts the electricity to alternating current (AC) for use by the building or home. Surplus PV electricity—more than the building can use—flows into the electric power grid.

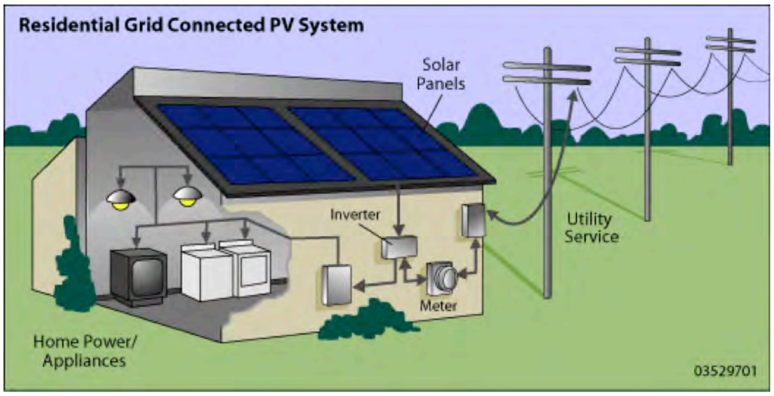

Figure G-4. Residential Distributed Generation PV System

Utility-Scale Solar PV. The PV panel arrays can also be mounted in large-scale ground mounted PV generating facilities (also referred to as "solar farms") that sometimes use tracking systems to actively tilt the PV panels towards the sun as it moves across the sky, thus increasing the annual capacity factor. These panels also produce direct current (DC) electricity. Inverters convert the electricity to alternating current (AC) where it immediately flows into the electric power grid.

Run-Of-River Hydroelectric

Hydropower is power derived from the energy of falling or moving water, which may be harnessed for useful purposes. Since ancient times, hydropower has been used to irrigate and operate various mechanical devices, such as watermills, sawmills, textile mills, dock cranes, and domestic lifts.

For run-of-the-river hydro projects, a portion of a river's water is diverted to a channel, pipeline, or pressurized pipeline (penstock) that delivers it to a waterwheel or turbine. If the river is not flowing, the hydroelectric facility produces no power. The moving water rotates the wheel or turbine, which spins a shaft. The motion of the shaft can be used for mechanical processes (such as pumping water) or it can power a turbine-generator to generate electricity.

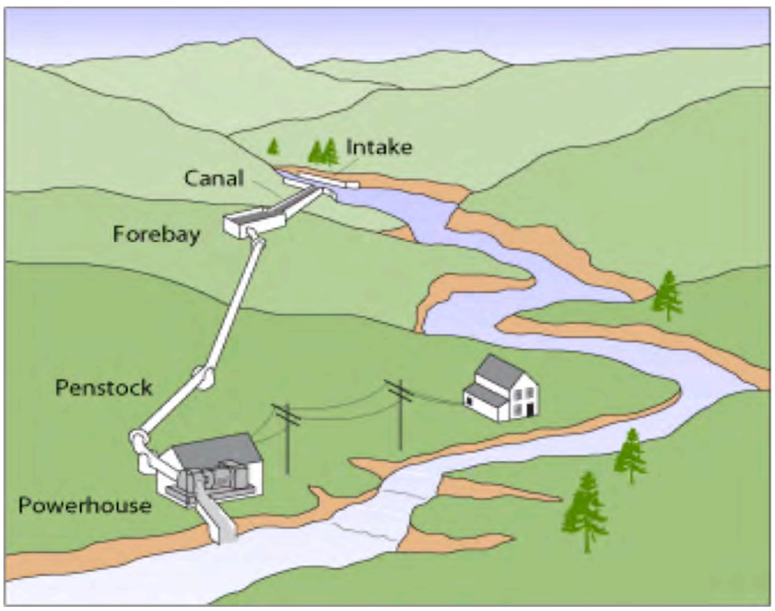

Figure G-5. Run-of-River Hydroelectric Plant

The primary development considerations are finding sites with adequate water flow and pressure, which are located in reasonable proximity to the electric grid for interconnection.

Energy Storage in Combination with Variable Renewable Energy

Wind, solar, and hydroelectric are all variable renewable energy sources. As such, they cannot be used to maintain the stability of an electric power grid, that delicate balance between supply and demand. Energy storage, however, can alleviate this situation and help provide more reliable energy, or in some cases, firm renewable power.

Energy storage can capture excess variable energy—generation that is not currently needed to meet demand—and store it in other forms until needed. This stored energy can later be converted back to its electrical form and returned to the grid as needed. Stored in high enough amounts, these sources could then be treated as firm power than may be scheduled and dispatched. (See Appendix J: Energy Storage Plan for more details.)

Pumped-storage hydroelectricity is a type of hydroelectric energy that includes energy storage. Water is pumped from a lower elevation to a higher elevation, where the stored water can be subsequently released through turbines to produce electricity. Electricity for pumping the water would typically occur during off-peak periods when the cost is low, or when during periods when there is excess energy generation from variable renewable resources. The generated electricity is then used during on-peak periods when demand is higher.

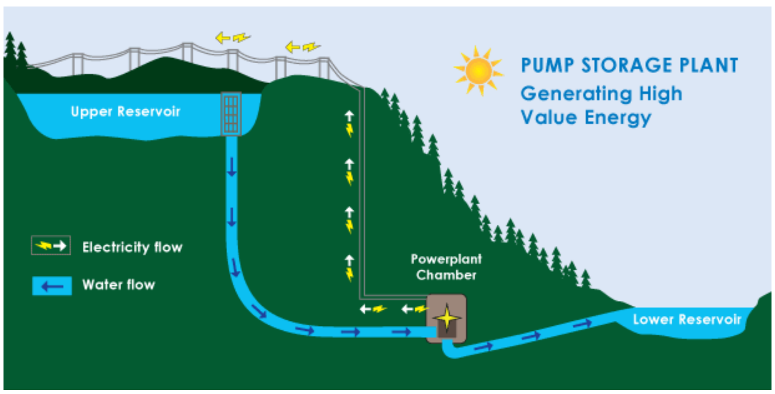

Figure G-6. Pumped Storage Hydroelectricity Plant

FIRM GENERATION

Several types of firm generation are included in our PSIP analysis, many of which are currently in our generation mix. Firm generation is predictable because its energy source (both fossil fuels and renewable fuels) can be scheduled, dispatched, and controlled.

The annual capacity value of firm generation can also be managed. A firm generation source can be operated as much or as little as necessary to meet demand. As such, firm generation is dispatchable; in other words, it can be used to help regulate the balance between supply and demand.

Gas Turbine Engine (or Combustion Turbine)

A gas turbine engine rotates as a result of hot gases (the product of the combustion of fuels) traveling through sets of turbine blades. As illustrated in Figure G-7, the flames themselves do not touch the turbine blades – just the gases produced by the flames. The combustor is where the fuel and air are mixed to enable the combustion process to occur. The fuel for this type of prime mover is either gas or liquid (not coal or biomass).

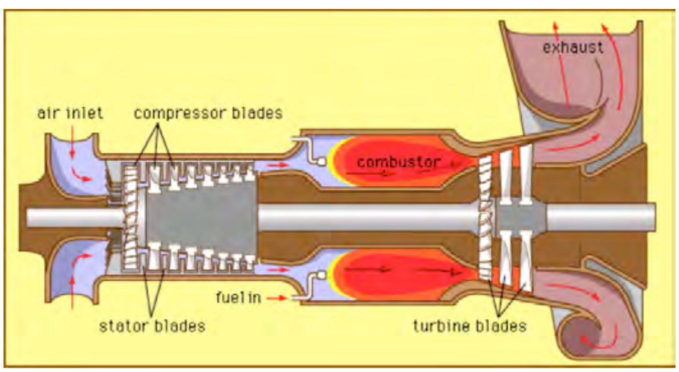

Figure G-7. Gas Turbine Engine

There are two types of gas turbines used for power generation: Aeroderivative and Frame.

Aeroderivative. This class of turbine is smaller (up to 100 MW) and can be quickly started and ramped, which makes them more compatible with grids that have large amounts of variable generation.

Frame. This type of turbine is generally larger (up to 340 MW), but not as fast reacting for both starting and ramping.

Gas turbines produce firm, dispatchable generation.

Steam Turbine: Combined Cycle and Boilers

A steam turbine operates by high pressure steam traveling through the turbine blades, causing the turbine shaft to rotate. This high pressure steam can be produced by a variety of technologies including Heat Recovery Steam Generators (HRSG) and fuel-fired boilers. All steam turbines produce firm, dispatchable generation.

Heat Recovery Steam Generators (HRSG)

HRSG use the high temperature exhaust gas from gas turbines engines to create steam for use in a steam turbine generator. This allows more electricity to be produced without using any additional fuel. The assembly of gas turbine, HRSG, and other auxiliary equipment used is referred to as combined cycle.

Hot combustion gases travel across the gas turbine blades to make the turbine spin where these gases are released at high temperature. A HRSG connects to the end of the gas turbine to take advantage of the energy that remains in the hot exhaust gases. The heat from these hot exhaust gases turns water contained in the HRSG into steam, where it is then sent to a steam turbine causing its connected generator to spin, thus producing electricity. Used steam is then converted back into water and reused again in the HRSG.

As illustrated in Figure G-8, combined cycle turbines can be either "single-train" (that is, one gas turbine and HRSG tied to the steam turbine) or "dual-train" two gas turbines and HRSG assemblies tied to a single steam turbine).

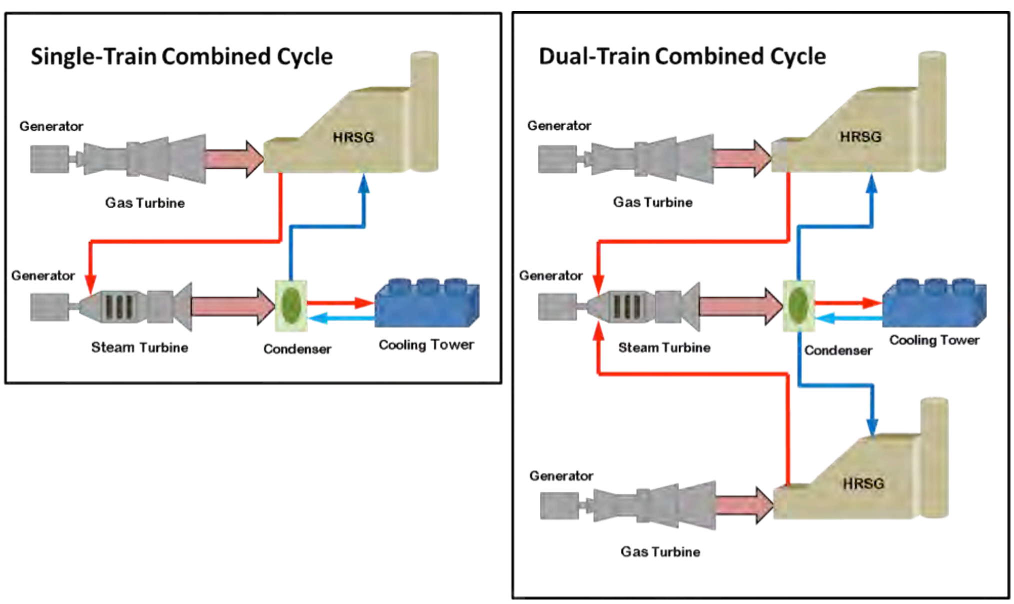

Figure G-8. Combined Cycle Plant: Single-Train and Dual-Train

A dual-train configuration provides twice as much power at a lower cost as a similar sized single-train configuration.

Reciprocating Internal Combustion Engine (RICE) or "Diesel Engine"

The type of reciprocating internal combustion engine used to produce electricity is a diesel engine. These engines can burn a variety of fuels, including diesel, biodiesel, biocrude, heavy oil, natural gas, and biogas. Diesel engines start and ramp quickly. Diesel engines produce firm, dispatchable generation.

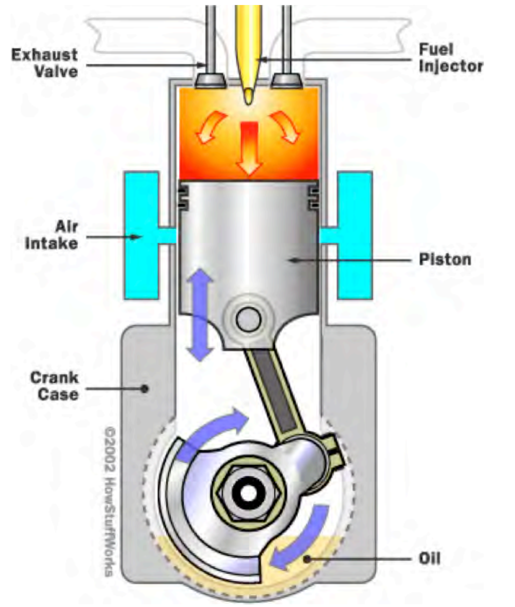

Figure G-9. Diesel Engine

Diesel engines have many combustion chambers called cylinders, each of which drives a piston connected to a common rotating shaft. This shaft is coupled to the generator to make it rotate. The number and size of these cylinders (illustrated as orange in the picture below) determine how much electrical output the engine can produce.

Diesel engine ratings can range from a few kW up to about 18MW. Larger diesel engines, because of their design, preclude them from meeting US Environmental Protection Agency (EPA) air emission limits. In addition, the EPA has different air regulations for diesel engines depending on the size of the cylinders.

Boilers (or Steam Generators)

A boiler furnace is made up primarily of small diameter (about 2-inch) metal tubes welded side by side to make a rectangular box. The tubes, which contain high purity water, are connected to a steam drum. The large fire inside the furnace transmits heat to the water inside the tubes to create steam in the steam drum. Fuel and air are continually added to the furnace to feed the fire.

Steam leaves the steam drum and travels through an independent set of tubes where it is heated to its final temperature by hot combustion exhaust gases. The steam then moves into the steam turbine, causing them to rotate and thus generate electricity. Boilers use a variety of fuels, including coal, biomass, liquid fuel oil, gas, and garbage.

Boilers come in many types, shapes, and sizes. Figure G-10 shows a simplified boiler steam turbine power plant. The boiler itself is outlined in the dotted red box.

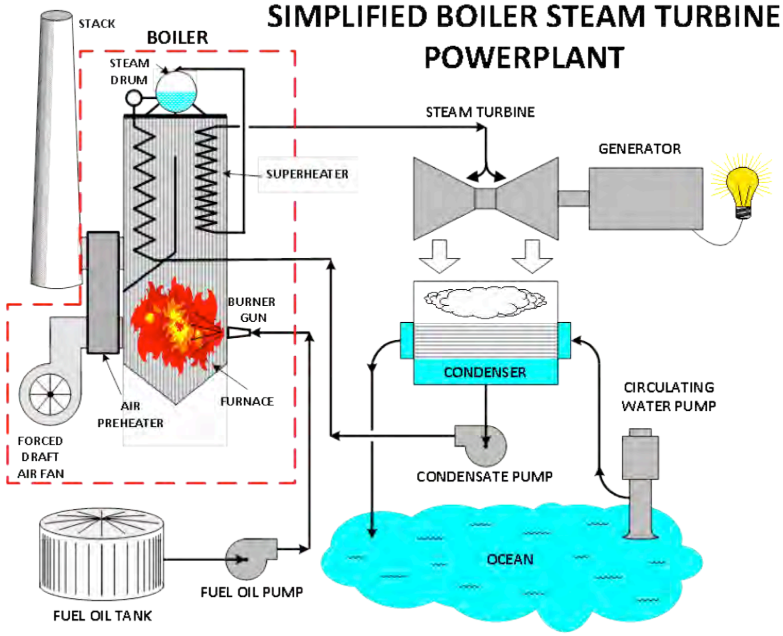

Figure G-10. Simplified Boiler Steam Turbine

Used steam can be converted back into water and reused in the boiler. A condenser forces the steam to travel over metal tubes that contain cold seawater, which causes the steam to turn back into water where it is pumped back into the steam drum, where the generation process begins again.

Renewable Fuel for Boilers–Waste (or Garbage)

Waste-to-energy is a renewable fuel-fired steam-electric power plant in which waste (or garbage) is burned in whole or in part as an alternative to fossil fuels. Paper, organics, and plastic wastes account for the largest share of solid waste used for the waste-to-energy stream. Incinerating solid waste to generate electricity is one method to reduce this waste volume. The fractions of solid waste—paper, wood waste, food waste, yard waste—are forms of a biomass fuel. Americans generate approximately 4.5 pounds of garbage per day. In Hawaiʻi, solid waste consists primarily of 30% paper, 25% other organics, and 12% plastics with the remainder comprised of metals, glass, and other materials.

Solid waste is mechanically processed in a “front end” system to produce a more homogenous fuel called refuse-derived fuel (RDF). RDF, in its simplest form, is shredded solid waste with the metals removed. This RDF must be processed further to remove other non-combustible materials such as glass, rocks, non-burnables, and aluminum.

Additional screening and shredding stages can be done to further enhance the RDF. The RDF is then fired in the boiler to produce steam that is directed to a turbine or generator.

In general, a robust waste-to-energy generation reduces the amount of landfill refuse by 90%.

Renewable Fuel for Boilers–Biomass

Biomass is another renewable fuel that can be used in boilers as alternatives to fossil fuels such as liquefied natural gas (LNG), oil, and coal.

Biomass is commonly defined as material derived from living organic matter (for example, trees, grasses, animal manure). Biomass includes wood and wood waste, herbaceous crops and crop wastes, food processing wastes such as bagasse, animal manures, and miscellaneous related materials. Biomass can be grown for the purpose of power generation from numerous types of plants, including switchgrass, hemp, corn, poplar, willow, sorghum, sugarcane, and a variety of trees such as eucalyptus and palm.

Biomass can either be burned directly to produce steam to make electricity, or processed into other energy products such as liquid or gaseous biofuel. In general, generating electricity directly from biomass is more efficient than converting it to biofuel. Siting a power generation facility at the source of the biomass, however, is not always feasible. Biofuel's transportability offers an attractive advantage.

Figure G-11 shows a process for converting wood waste into a biogas, which is then burned to create steam to generate electricity.

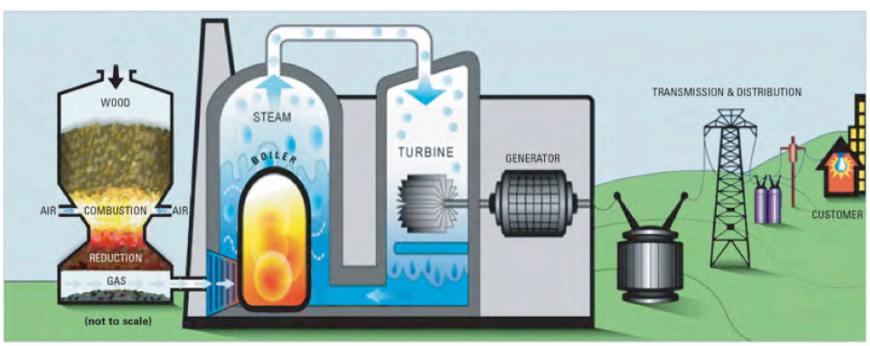

Figure G-11. Biomass Gasification

Aside from their fuel coming from renewable biomass, the power generation components of these facilities are similar to conventional power plants. In many cases, the power plants burn a combination of biofuel and fossil fuel.

Geothermal

Geothermal energy is heat energy from the earth. A layer of hot and molten rock called magma lies below the earth's crust. Heated ground water exposed to this magma can be extracted to provide geothermal energy at the surface. Resources of geothermal energy range from the shallow ground to hot water and hot rock found a few miles beneath the earth's surface where the earth's crust is thinner.

In general, geothermal fluids are tapped through wells, also referred to as "bores" or "bore holes". Except for the higher geothermal temperatures, these wells are similar to oil and gas wells. Geothermal well depths typically range from 600 to 10,000 feet. The fluids surging out of the wells are piped to the power plant. Geothermal steam, or vapor created using geothermal hot water, then spins a turbine-generator to create electricity.

The temperature and quality of the geothermal fluid determines which of the four types of power system that can be used for electrical generation.

Dry Steam Plants. Hot 100% steam is piped directly from geothermal reservoirs into generators in the power plant. The steam spins a turbine-generator to produce electricity. The steam is re-injected into the ground. Dry steam geothermal power plants are rare.

Flash Steam Plants. Fluids between 300°F and 700°F (148–371°C) are brought up through a well. Some of the water turns to steam, which drives the turbine-generator. When the steam cools, it condenses back into water and is re-injected into the ground.

Binary Cycle Plants. Moderately hot geothermal water (less than 300°F) is passed through a heat exchanger. This heat is then transferred to a working fluid (such as isobutene or isopentane) which boils at a lower temperature than water. When that fluid is heated, it turns to vapor which spins the turbine-generator.

Hybrid Plants. Combination of the flash steam and binary cycles.

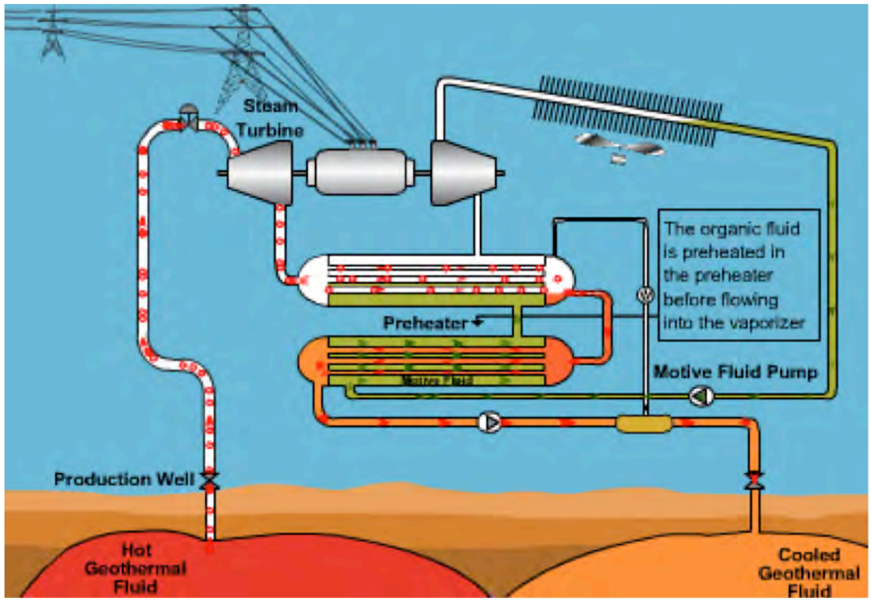

Figure G-12. Geothermal Hybrid Plant

In relation to other renewable energy projects, developing a geothermal power project is relatively complex, and typically involves two major phases: (1) exploratory drilling and (2) project development. The exploratory drilling phase identifies and evaluates potential resources, and drills test well. This phase usually takes a number of years, and in some case, does not identify a viable geothermal resource. After a geothermal resource has been identified, the project development phase begins, which includes drilling production wells and constructing a power plant.

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H. Commercially Ready Technologies

Our analysis for the PSIPs considered both commercially ready generation technologies as well as emerging technologies that, while not commercially ready, might become available during the planning period (2015–2030).

Which emerging technology will be commercially ready before 2030 is impossible to know with any degree of certainty. As a result, with one exception, we did not attempt to decide which of the most promising of the emerging technologies might become available during the planning period. The exception: our analyses performed limited sensitivity of some emerging technologies (for example, Ocean Thermal Energy Storage) to quantify any potential future value.

Our PSIPs are snapshots of the future based on our best available assumptions. As such, *for the PSIPs, we limited the generating resource options to those technologies that are commercially ready as of 2014.*

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 will evaluate any proposal on its commercial viability as well as other attributes that are consistent with RFP requirements. Further, nothing in these planning assumptions is intended to modify or change our position for welcoming test projects, pilot projects, or negotiations that involve any specific technology.

COMMERCIAL READINESS INDEX

In order to evaluate whether a technology is commercially ready, the Hawaiian Electric Companies used the Commercial Readiness Index (CRI) methodology developed by the Australian Renewable Energy Agency (ARENA), which was released in February 2014.[1]

NASA first developed a Technology Readiness Level (TRL) in 1974.[2] The TRL ranks technology readiness on a scale of 1 to 9 (1 being the lowest; 9 being the highest level of readiness), with specific attributes identified for each level of readiness.

In 2011, the U.S. Department of Energy published the *Technology Assessment Readiness Guide*,[3] a framework for evaluating energy technologies using the TRL methodology. The TRL methodology characterizes technology readiness from very early stages of a technology life cycle, up to and including commercial readiness.

Building on the work of NASA, ARENA developed a Commercial Readiness Index (CRI), and published the CRI criteria in February 2014 in a document titled *Commercial Readiness Index for Renewable Energy Sectors*.

The CRI scale (1 to 6, with 6 being the highest level of readiness) assesses technology readiness against eight indicators:

- Regulatory environment
- Stakeholder acceptance
- Technical performance
- Financial performance (cost)
- Financial performance (revenue)
- Industry supply chain
- Market opportunity
- Vendor maturity (preference for established companies with strong credit ratings)

ARENA maps its CRI to the TRL, with CRI level 1 corresponding to TRL levels 2 through 8, and CRI level 2 corresponding to TRL level 9. CRI levels 3 through 6, then, include more mature technologies that are closer to commercial deployment, or that are already being used commercially. Except for certain sensitivity analyses, the PSIP did not consider any technologies with a CRI level 4 or less.

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1 *Commercial Readiness Index for Renewable Energy Sectors*. Australian Renewable Energy Agency. © Commonwealth of Australia, February 2014. http://arena.gov.au/files/2014/02/Commercial-Readiness-Index.pdf

2 "Technology Readiness Levels Demystified." August 20, 2010. http://www.nasa.gov/topics/aeronautics/features/trl_demystified.html#.U7W-g7ZdV9c

3 Technology Level Assessment Guide. September 15, 2011. http://www2.lbl.gov/dir/assets/docs/TRL%20guide.pdf

To evaluate power generating technologies included in analysis performed for the PSIPs, the CRI methodology provides practical, objective, and actionable guidance. Therefore, we used this methodology to evaluate emerging generation technology options and their suitability for inclusion as resource options in the PSIPs.

For the PSIPs, only those technologies with a CRI Level of 5 or 6 were considered commercially ready, and included as resource options in the PSIPs.

Table H-1 defines the levels of commercial readiness under the CRI methodology.

CRI Level	Commercial Readiness	Definition[4]
6	Bankable grade asset class	Financial investors view the technology risk as low enough to provide long-term financing. Known standards and performance expectations are in place, along with appropriate warranties. Vendor capabilities (including both technology vendors and EPC vendors), pricing, and other market forces drive market uptake ("demand pull").
5	Market competition driving widespread deployment	Competition is emerging across all areas of the supply chain, with commoditization of key components and financial products.
4	Multiple commercial applications	Full-scale technology demonstrated in an industrial (that is, not R&D) environment for a defined period of time. May still require subsidies. Publicly verifiable data on technical and financial performance. Interest from debt and equity sources, although still requiring government support. Regulatory challenges being addressed in multiple jurisdictions.
3	Commercial scale-up	Deployment of full-scale technology prototype driven by specific policy. The commercial proposition is driven by technology proponents and by market segment participants (a "supply push"). Publicly discoverable data is driving interest from finance and regulatory sectors, but financing products are not yet widely available. Continues to rely on subsidies.
2	Commercial trial	Small scale, first-of-a-kind project funded by 100% at-risk capital and/or government support. Commercial proposition backed by evidence of verifiable performance data that is typically not available to the public. Proves that the essential elements of the technology perform as designed.
1	Hypothetical commercial proposition	Technically ready, but commercially untested and unproven. The commercial proposition is driven by technology advocates, with little or no evidence of verifiable technical data to substantiate claims.
0	Purely hypothetical[5]	Not technically ready. No testing at scale. No technical data.

Table H-1. Commercial Readiness Definitions

[4] Based on *Commercial Readiness Index for Renewable Energy Sectors*. Australian Renewable Energy Agency. © Commonwealth of Australia, February 2014. Table 1. p 5.

[5] Not a part of the CRI methodology. Defined here to classify commercial readiness of certain technologies discussed from time to time in Hawai'i.

EMERGING GENERATING TECHNOLOGIES

In Hawai'i, certain emerging generating technologies are discussed as potential generating resource options. The most prominent of these are ocean wave/tidal power, ocean thermal energy storage (OTEC), and concentrated solar thermal power (CSP). We evaluated each of these technologies using the CRI ranking methodology. As objective as the CRI methodology attempts to be, the mapping of the indicators for a given technology is necessarily subjective. Reasonable differences of opinion in the state of any one (or even several) of the eight categories of indicators would not change the overall conclusion regarding the commercial readiness of these technologies.

Summary of CRIs for PSIP Resource Candidates

Table H-2 summarizes the commercial readiness of various generating resource technologies.

	CRI Level								
Technology	0	1	2	3	4	5	6	PSIP Resource Option?	Comments
Simple cycle combustion turbine (CT)							x	Yes	
Combined cycle CT + heat recovery steam							x	Yes	
Internal combustion engines—small							x	Yes	
Internal combustion engines—large							x	Yes	
Geothermal							x	Yes	Constrained on Maui and Hawai'i. None for O'ahu.
Biomass steam							x	Yes	
Biomass gasification			x					No	
Run-of-river hydro							x	Yes	Limited amount of MW available in Hawai'i.

Technology	CRI Level 0	1	2	3	4	5	6	PSIP Resource Option?	Comments
Storage hydro							x	No	No available streams to dam for water storage.
Pumped storage hydro							x	Yes	Not considered for base cases. Sensitivities only.
Ocean wave/ tidal				x				No	
Ocean thermal (OTEC)			x					No	
Wind—onshore utility scale							x	Yes	Limited on O'ahu.
Wind—offshore utility scale					x			No	High capital cost, concerns with ability to site and permit.
Wind—distributed generation				x				No	Approximately 3–4 times more expensive installed cost compared to solar DG-PV.
Solar PV—utility scale						x		Yes	
Solar PV—distributed						x		Yes	
Concentrated solar					x			No	
Fuel cells—distributed			x					No	Primary applications are for "high 9s" reliability applications (e.g., data centers).
Fuel cells—utility scale			x					No	
Micro nuclear reactors		x						No	
Solar power satellites	x							No	
Nuclear fusion		x						No	
Energy harvesting from ambient environment	x							No	Early markets will likely be small scale applications, such as PDA charging.

Table H-2. Commercial Readiness of Generating Technologies Considered for PSIPs

Evaluation of Emerging Technologies

Table H-3 through Table H-5 are CRI assessments of emerging generation technologies that were not included as resource options due to a CRI level of 4 or less.

Table H-3 evaluates wave and tidal power as a potential generating resource as, at best, CRI level 3. Therefore, it was not included for consideration in the PSIPs.

CRI Level	Regulatory Environment	Stakeholder Acceptance	Technical Performance	Financial Performance (Cost)	Financial Performance (Revenue)	Supply Chain	Market Opportunity	Company Maturity
6								
5							Market opportunity widely understood. Additional policy support needed to drive uptake.	
4			Performance understood; high confidence in performance.					
3				Various versions of technologies deployed; Cost drivers beginning to be understood.				
2	Ability to permit across various regulatory jurisdictions untested.	Stakeholder support case-by-case basis.			Revenue projections being tested, however investment community not yet willing to underwrite PPAs on widespread basis.	Supply chain not available. Each project typically unique specification. EPC based on time and materials.		
1								Established industry players not yet part of sector.

Table H-3. Wave/Tidal Power Commercial Readiness Evaluation

Table H-4 evaluates ocean thermal energy conversion as a potential generating resource as, at best, CRI level 3. Even though the CRI level would suggest that OTEC is not eligible for consideration at this time, due to interest in this technology for Hawaiʻi and our ongoing negotiations with OTEC International to build an OTEC facility to service Oʻahu, a sensitivity was prepared to evaluate OTEC as a resource option for Oʻahu.

CRI Level	Regulatory Environment	Stakeholder Acceptance	Technical Performance	Financial Performance (Cost)	Financial Performance (Revenue)	Supply Chain	Market Opportunity	Company Maturity
6								
5								
4								Established player (LMCo) considered part of sector.
3							Size of potential market is understood.	
2	Regulatory issues require specific project consideration.	Stakeholder support a case-by-case basis.	Performance forecasts based on pilot project data.	Key costs based on projections. No data at scale.	Revenue projections at scale not tested.			
1						Key elements from specialists.		

Table H-4. Ocean Thermal Energy Conversion (OTEC) Commercial Readiness Evaluation

Table H-5 evaluates concentrated solar thermal power as a generating resource at a CRI level 4. While this resource might be considered during our next planning cycle, it was not included in the PSIPs.

CRI Level	Regulatory Environment	Stakeholder Acceptance	Technical Performance	Financial Performance (Cost)	Financial Performance (Revenue)	Supply Chain	Market Opportunity	Company Maturity
6							Market opportunities clear and understood.	
5					Target is to be cost competitive by 2020.[6]			Leading players with significant balance sheets in sector.
4	Permitting, regulatory challenges based on actual evidence. Policy settings moving to “market pull”.	Evidence and experience available to inform stakeholders.	Performance understood. High confidence in future project performance.	Cost drivers understood and tested.	Financing still largely underwritten with government guarantees and subsidies.[7]	Limited supply options but improving.		
3			Multiple technology designs.					
2								
1								

Table H-5. Concentrated Solar Thermal Power (CSP) Commercial Readiness Evaluation

[6] See “*2014, The Year of Concentrating Solar Power.*” U.S. Department of Energy. May 2014.
[7] *Ibid.*

I. LNG to Hawaiʻi

Liquefied natural gas (LNG) is critical to reducing customer bills and improving environmental quality in Hawaiʻi. High oil prices and more stringent air regulations (the Environmental Protection Agency's Mercury Air Toxic Standards (MATS) and National Ambient Air Quality Standards (NAAQS)) increase the need to reduce Hawaiʻi's dependence on oil. While the majority of Hawaiian Electric's current generation portfolio utilizes oil, LNG has emerged as a viable alternative fuel source that may substantially lower fuel costs while reducing greenhouse gas emissions. In late 2012, the Hawaiian Electric Companies and FACTS Global Energy completed studies that confirmed both the technical and commercial feasibility for importing and utilizing LNG in Hawaiʻi.

DELIVERING LNG TO HAWAIʻI

Natural gas is not indigenous to Hawaiʻi and must first be liquefied into LNG to be cost effectively transported to Hawaiʻi. LNG can be imported to Hawaiʻi in two ways: bulk LNG or containerized LNG

Bulk LNG. LNG could be transported in bulk via LNG carriers and/or articulated tug barges (ATBs) and received at a bulk LNG import and regasification terminal. The Floating Storage and Regasification Unit (FSRU) is a variant of this option. Pearl Harbor is the best site available for an FSRU when considering factors such as favorable meteorological-ocean conditions, spacious and protected harbor waters, security, cost, and ability to break-bulk (for distribution to the neighbor islands). Natural gas would then be distributed from the FSRU by pipeline to facilities on the individual islands where it would be consumed. Based on our discussions with FERC, we anticipate that a bulk LNG import and regasification terminal project for Hawaiʻi will take approximately

6–8 years to complete (1–2 years planning, 2–3 years FERC permitting, and 2–3 years construction) and could possibly be placed in service between 2020 and 2022.

Containerized LNG. LNG could be transported in International Organization for Standardization (ISO) containers using conventional container ships and trucks equipped to handle standard shipping containers. The LNG ISO containers would be delivered directly to the facilities where the LNG would be regasified and consumed. Since FERC permitting is not likely required for LNG delivered by ISO containers, LNG is available today in small quantities, and within a relatively short time for larger quantities.

Containerized LNG RFP

The Company issued an RFP in March 2014, for LNG to be delivered to Hawai'i in ISO containers (Containerized LNG RFP). We have completed our evaluation of the proposals and have identified two proposals for more in-depth discussion with the bidders. We currently anticipate negotiating and executing a contract, and subsequently submitting an application to the Commission in the fourth quarter of 2014.

The Containerized LNG RFP called for deliveries to start within a window from October 1, 2016 to June 30, 2017. Based on confidential information received via the Containerized LNG RFP process, we believe that an LNG delivery commencement date in the latter part of 2017 remains viable if the following five key milestones are realized by their noted deadlines.

1. Finalization of the LNG Sales and Purchase Agreement (SPA) by fourth quarter 2014.
2. Application submission to the Commission by fourth quarter 2014.
3. Final Order to import LNG issued by the Commission by June 1, 2015.
4. Granting of all other major permits by June 1, 2015.
5. Clearance or waiver of any remaining LNG SPA conditions precedent by July 1, 2015.

Upon achievement of these milestones, we will make the investments necessary to construct, assemble and aggregate the various pieces of the supply chain needed to deliver LNG to Hawai'i in 2017. It nevertheless must be recognized that these milestones are challenging, some of which are beyond our control and they will only be realized if no significant legal, environmental, or social obstacles encumber the process.

DELIVERING LNG IN 2017

Liquefaction Capacity

We believe that ensuring the availability of LNG supply from FortisBC is a critical component for successfully concluding the Containerized LNG RFP process with an executed LNG supply and logistics contract. FortisBC's liquefaction capacity is available under a regulated tariff as early as 2017 and capacity is reserved on a first come, first served basis. The Company believed it was critical to directly secure the required capacity from FortisBC before other parties stepped in. For this reason, on August 8, 2014, we executed an agreement with FortisBC for LNG liquefaction capacity under the FortisBC Rate Schedule 46. FortisBC's liquefaction cost, which is less than $2.70, is competitive with other liquefaction rates and is, in fact, lower than any other rate we are aware of (including the rates offered by other Gulf of Mexico liquefaction projects). In addition, because FortisBC is in British Columbia, Canada, they are not subject to the Jones Act and, therefore, can provide substantial marine transport savings to Hawaiian Electric through the use of international shipping assets.

COST OF SERVICE

The range of proposed conditional delivered LNG pricing to O'ahu power plants and to Hawai'i Island power plants is extremely favorable, and based on the assumed forecasted 2017 natural gas pricing of $3.58/MBtu.

The pricing mechanisms incorporate pass through provisions of most fixed and variable cost components, with the cost stack to be finalized upon filing of the LNG Sales and Purchase Agreement with the Commission. The build-up of the proposed pricing is based on bidders' current cost estimates, and the ranges for fixed, fixed with escalation, and variable price components.

Included in the fixed cost component are the capital assets (marine assets, ISO containers, etc.) and any services that can be contracted at fixed cost over the term of the SPA. The fixed with escalation cost component include the FortisBC liquefaction costs and other labor costs such as marine terminal handling charges and trucking. Included in the variable cost component is the gas commodity, pipeline toll, and fuel consumed for liquefaction, shipping, and trucking.

The Company and our advisors are undertaking due diligence on the cost elements for each segment in the supply chain. Liquefaction costs are set by FortisBC's Rate Schedule 46 and may be subject to periodic adjustments, if approved by the British Columbia

Utilities Commission (BCUC). Analysis to date suggests that there is little risk of a cost increase over the bidder's estimates, assuming the above stated milestone are achieved by the milestone dates and the SPA is effective no later than July 1, 2015. Discussions regarding the costs are ongoing with the bidders.

To account for the possibility of stranded assets that could result from a transition to a bulk terminal, a cost adder was included in the LNG forecast between the years of 2017 and 2021 to reflect the potential for a reduced amortization period (5 years versus 15 years).

Transition to Bulk Terminal: 2022

The development of a bulk receiving terminal will be subject to FERC review and approval and therefore cannot be realistically achieved by 2017. Siting of such a terminal, whether floating or land-based, will require substantial engineering analysis and stakeholder socialization. After consulting with FERC, a realistic schedule to develop a bulk LNG terminal is approximately 6 to 8 years.

The Galway Group estimated LNG pricing for 2022 and beyond by using current gas commodity forecasts, liquefaction costs from FortisBC, and estimated costs for shipping of the LNG and for a bulk terminal utilizing a FSRU. We are also assuming annual price increases in our forecasting. The build-up of the LNG forecast for 2022 is as follows:

Item	Price
Gas Commodity	$4.31
Pipeline Header (Fixed)	$0.60
Pipeline Cost of Fuel	$0.11
Marketer Fee (Fixed)	$0.01
Liquefaction (Fixed)	$1.99
Liquefaction Cost of Power	$0.91
Process Fuel Gas	$0.04
B.C. LNG Export Tax	$0.00
Marine Terminal	$0.33
LNG FOB FortisBC	$8.30
Shipping	$1.89
FSRU + Gas Pipeline	$2.54
2022 LNG Forecast w/ Bulk Terminal	$12.73

Table I-1. LNG Itemized Pricing

The LNG price forecast escalates beyond 2022 due to increases in the gas commodity price forecast, which is derived from NYMEX futures-derived forecasted values for Henry Hub; and 2% inflation adjustment applied to fixed with escalation and variable cost components.

J. Energy Storage For Grid Applications

Electricity is a commodity that is most efficiently produced when it is needed. The continuously varying demand for electricity requires utilities to have the appropriate mix of generating and demand-side resources to meet these varying demands. Energy storage is an extremely flexible tool for managing the supply-demand balance.

- Energy storage can be a substitute for generation resource alternatives;
- Energy storage can be used in conjunction with generation to help optimize generation capital costs and reduce system operating costs;
- For system security and reliability applications, storage has unique operational characteristics that may provide benefits not available through other resources.

The ability of energy storage to serve in any one of these roles is dependent upon the cost-effectiveness and operational characteristics of the energy storage asset under consideration, and the operational characteristics of all resources on the system.

Until relatively recently, the only way to store electricity in large (or bulk) quantities has been large mechanical storage devices (for example, pumped storage hydro, compressed air energy storage), which are highly dependent on site availability, may face substantial permitting and public acceptance challenges, have high capital costs and require long lead times (more than seven years) to develop. A new generation of chemical energy storage technologies (that is, batteries with new chemistries) and large-scale flywheel devices add to the commercially available options for energy storage in grid applications. In addition, there may be opportunities to aggregate customer-owned energy storage to provide value to all customers.

The Commission requested in the April 28, 2014 Decisions and Orders (D&Os) that the Companies consider the role that energy storage can play in managing the reliability of the electric grid. More specifically, the D&Os include the following topics for the Companies to address in the PSIPs:

- Discuss potential energy storage technologies and their capabilities;
- Analyze the fundamental benefit and costs of energy storage technologies;
- Discuss how energy storage is utilized in the preferred resource plan;
- Provide a plan for utilization of energy storage resources to address steady state frequency control and dynamic stability requirements, and to mitigate other renewable energy integration challenges;
- Provide a plan to improve utilization of existing energy storage on Maui and Lanai to improve system reliability and reduce system operation costs in those systems;
- Discuss the use of customer-side energy storage;
- Analyze the use of pumped storage hydro to provide ancillary services and bulk energy storage for renewable energy.

The Companies share the Commission's interest in energy storage for providing essential grid services. Energy storage has been integrated with certain independent power producer (IPP)-owned wind and solar projects to help manage ancillary service requirements. A project to design and procure storage for contingency reserves to mitigate the impacts from distributed solar on system security was initiated for the Hawaiʻi Electric Light system. Recently, a Request for Proposals (RFP) for commercial-scale and use of energy services to provide ancillary services was issued by Hawaiian Electric. As more fully described herein, the Companies have also implemented several pilot and demonstration projects.

This Appendix J will address the Commissions' questions about the Companies' plans to utilize energy storage in their systems.

COMMERCIAL STATUS OF ENERGY STORAGE

Pumped storage hydroelectric and compressed air energy storage technologies are mature and proven, with a great deal of performance data in commercial applications. Batteries (particularly lead-acid) and flywheel type energy storage devices have been around for many years and could also be considered mature technologies, but not for grid level applications such as renewable energy integration on island-based grids. The use of batteries and flywheel devices for use in bulk power systems and applications to integrate, or mitigate the impacts of, intermittent renewable energy in island-based electric grid systems is relatively new and there is somewhat limited data regarding their performance in commercial power grid applications. It is therefore worth discussing the status of commercialization of battery and flywheel energy storage for grid applications. This section will discuss several aspects[1] of the status of these technologies in terms of their commercialization. The evidence points to these technologies being at the cusp of commercially readiness.

Regulatory Environment

The regulatory environment for energy storage manufacturers is favorable. Most notably, on October 21, 2013 the California Public Utilities Commission (CPUC) issued the "Decision Adopting Energy Storage Procurement Framework and Design Program[2]." This CPUC decision set a target of 1,325 MW of energy storage to be installed in the three major investor-owned utility systems in California by the end of 2024. Other state commissions are looking at this CPUC decision[3]. This decision provides commercial opportunities for energy storage technology companies and energy storage project developers, and is therefore favorable for the commercial readiness of energy storage technologies. Of interest, the decision excludes pumped storage hydroelectric projects larger than 50 MW, a mature technology, from the target in order to promote development of smaller grid-scale storage projects.

At the federal level, the Federal Energy Regulatory Commission's (FERC) Order No. 755[4], required wholesale markets to develop compensation mechanisms for the provision of frequency regulation, a service that is technically well suited for certain energy storage technologies. The regulatory accounting treatment for energy storage remains an area that will require additional discussions by electric utilities and regulators[5]. For example, energy storage might be implemented for the purpose of relieving grid congestion (functionally classified as transmission), but the same energy storage project might also be able to provide ancillary services (functionally classified as a production service). Grid level energy storage might be implemented to mitigate the effects of variable distributed generation, while at the same time providing other grid support services. However,

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[1] See Appendix G for a discussion of the "Commercial Readiness Index" (CRI) and the factors that are considered in determining a CRI.

[2] Decision 13-10-040, October 17, 2013 (issued October 21, 2014). PUC Rulemaking 10-12-007. Order Instituting Rulemaking Pursuant to Assembly Bill 2514 to Consider the Adoption of Procurement Targets for Viable and Cost-Effective Energy Storage Systems. Full decision available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M079/K533/79533378.PDF

[3] "California poised to adopt first-in-nation energy storage mandate." San Jose Mercury-News. October 16, 2013.

[4] *Frequency Regulation Compensation in Organized Wholesale Power Markets*. FERC Order No. 755. FERC Docket Nos. RM11-7-000 and AD10-11-000. Issued October 20, 2011. Order 755 available at: http://www.ferc.gov/whats-new/comm-meet/2011/102011/E-28.pdf

[5] Bhatnagar, Currier, Hernandez, Ma, Kirby. *Market and Policy Barriers to Energy Storage Deployment*. Sandia National Laboratory. Report SAND2013-7606. September 2013. Report available at: http://www.sandia.gov/ess/publications/SAND2013-7606.pdf

when leveraging storage for multiple purposes, the energy storage must retain the necessary charge level to satisfy the requirements for each use. For example, storage that is deferring transmission investment must retain sufficient charge to handle the transmission constraint; that stored energy cannot be used to provide other services. These situations present issues for regulators in terms of ensuring that the benefits and costs of energy storage are properly allocated.

Stakeholder Acceptance

There are several dimensions to stakeholder acceptance of energy storage technologies, including:

Industry Acceptance: The electric utility industry, including non-utility project developers, has generally accepted grid-scale energy storage technologies as viable solutions for meeting grid needs. This is evidenced by installations of several hundred megawatts of energy storage worldwide in the past few years, including installations in Hawaiʻi in conjunction with wind and solar projects. Automotive applications for batteries in electric vehicles are expected to drive manufacturing costs down for lithium-ion batteries.[6] As a result, utility industry planners expect distributed energy storage to become more economical and are preparing for distributed storage integration into the future grid.

Equitable Regulatory Environment: Monetization of energy storage benefits is generally available in competitive wholesale market environments, where there are markets for capacity, energy and ancillary services. Monetization in vertically integrated utility markets (including Hawaiʻi) is generally driven by the cost effectiveness of energy storage relative to alternatives that provide similar functions. Cost recovery of energy storage systems is for the most part rationalized in the market. It is worth noting that energy storage project installations do not typically qualify for tax incentives, except in limited circumstances[7].

Public Concerns: Energy storage technologies are generally considered to be safe, however, there are public concerns with these systems related to potential fire hazards, toxic waste disposal, and dam breaches.

Financial Community Acceptance: Most of the capital invested in this sector to date has been in the form of venture capital funding, the purpose of which is to commercialize and refine the technologies and develop viable business models. To date, there is no known example of project level debt financing using project debt secured only by the revenues and the project itself (a typical financing model in the IPP industry). Rather,

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6 See for example: http://www.electric-vehiclenews.com/2010/03/deutsche-bank-battery-costs-appear-to.html

7 For an example of such exceptions, see http://www.chadbourne.com/Large-Batteries-11-30-2011/

most of the projects have been financed off of the balance sheets of the developers themselves. As the market for energy storage becomes more of a "demand-pull" (as opposed to "supply-push") the interest of the mainstream investment community is growing. Several large financial institutions are marketing financing solutions for energy storage8. Some financial analysts predict that distributed energy storage, when combined with distributed solar PV, is on the cusp of being a technology that is disruptive to the traditional utility business model9.

Technical Performance

Although in general this industry is still in the formative stages, the technical performance of energy storage technologies, particular battery, flywheel systems, and pumped storage hydroelectric is well understood. And, with several hundred megawatts of grid-scale energy storage devices installed worldwide, the body of data is growing rapidly. The technical performance of most of the grid-scale energy storage projects to date (excluding pumped storage hydroelectric) is underwritten with technology performance guarantees (with liquidated damages provisions) from well-capitalized, strong balance sheet, engineering-procurement-construction (EPC) contractors and/or project developers.

Distributed energy storage is being marketed to customers interested in PV as well as enabled by the advent of electric vehicles (EV's) and the interest on the part of the sellers of EV's to address consumer "range-anxiety." Improvement in EV battery technology will increasingly find its way into distributed energy storage applications for consumers, including the ability to use EV's as a storage device for energy consumed in a customer's premises.

Financial Performance

The financial performance of energy storage is dependent upon the particular grid application and energy storage technology being deployed. Grid-scale energy storage costs are still relatively high[10]. In general, the cost of energy storage systems is declining, but challenges remain to deliver grid scale energy storage at low costs. Some sources believe that energy storage costs will decline precipitously over the next decade, at a rate of cost decline similar to that experienced with solar PV technology cost[11]. With respect

8 For example see: http://www.goldmansachs.com/what-we-do/investing-and-lending/middle-market-financing-and-investing/alternative-energy/

9 See for example: http://www.utilitydive.com/news/barclays-downgrades-entire-us-electric-utility-sector/266936/

10 See: Bhatnagar, Currier, et. al.

11 For example, see: http://rameznaam.com/2013/09/25/energy-storage-gets-exponentially-cheaper-too/

to value (benefits) of utility scale grid storage, as technology improves, the ability of energy storage to cost effectively provide grid services also increases.

Industry Supply Chain and Vendor Maturity

While the energy storage industry has its share of venture capital backed startups, large and well-capitalized equipment manufacturers now offer grid level energy storage technologies and solutions. These companies include, but are not limited to: General Electric, Hitachi, LG, Panasonic and NEC. Tesla Motors has recently announced that it is seeking a location for a large battery manufacturing plant in the US, to supply batteries for its EV's. They are actively developing utility uses for these same batteries and may find their way into grid storage applications, including distributed energy storage. Many of the smaller startups and niche players enjoy investments from, and strategic partnerships with, larger companies. These trends indicate that larger manufacturing companies are making the investments in sales, manufacturing, and service ecosystems that support the long-term viability of the energy storage industry. To date however, there is a lack of standardization in the energy storage industry.

Market Opportunity

The market opportunity for grid-scale energy storage is clearly validated by successful deployments worldwide and by regulatory mandates for energy storage as described above. Distributed energy storage is also viewed as a large market opportunity.

In conclusion, while the grid-scale energy storage industry is clearly in the early stages of commercial viability, it is well beyond the "technology development" stage for many of the available technologies. The Companies can be reasonably confident that energy storage solutions are available that can be designed, financed, constructed, operated and maintained in a manner consistent with the way the Companies deploy other kinds of utility grid infrastructure.

ENERGY STORAGE APPLICATIONS

Defining Characteristics of Energy Storage

Stored energy is generally referred to in physics as "potential energy." Potential energy is found in various forms; for example, the chemical energy stored in the form of a fuel, mechanical energy stored in a spring, gravitational energy stored in water in a reservoir, etc. In practice, most energy storage systems are used to store energy for use (that is, conversion to "kinetic energy") at a later time.

Energy storage systems of interest for electricity grid applications can be defined by the following set of characteristics:

Storage: Amount of energy that can be stored (measured in megawatt-hours)

Capacity (or rate of discharge): the rate (quantity per unit of time) at which the energy storage device can deliver its stored energy to the grid (typically measured in megawatts).

Storage Duration: Hours or minutes of energy storage (this is the amount of energy that can be stored divided by the rate of discharge).

Maximum Depth of Discharge: This is defined by the energy stored in the device at its minimum level divided by the total energy storage. This is a limiting factor in terms of the actual duration of delivery of stored energy from the device to the grid, since once the device reaches its maximum depth of discharge it cannot release any more of its stored energy. This can be a function of chemistry (for example, in a battery) or physical design (for example, in a pumped storage hydroelectric reservoir).

Round trip efficiency: This is the ratio of stored energy available for "release" from the device (AC energy out) to the amount of energy that must be expended to "fill" the device (AC energy in). The perfect storage device would have 100% round trip efficiency (that is, the energy output of the storage device would be equal to the charging energy required.) Actual storage efficiencies range from 70% to 90% depending upon the type of device, size and technology.

Duty Cycles Available: The number of charge/discharge cycles available from the device during a given period of time (measured in cycles per unit of time, for example, cycles per year, cycles per minute).

Grid Applications for Energy Storage

Generalized energy storage applications in electric power grids include the following:

Load Serving Capacity: Energy storage devices can be used to provide the equivalent of generating capacity, provided that the available storage duration is long enough (typically hours). Practical applications include substitution for peaking plants such as combustion turbines in markets where additional capacity is required[12]. In such an application, lower cost generating resources would be used to "fill" the energy storage device, and the stored energy would be released at a later time during peak hours. Load serving capacity requires relatively long storage durations (at least 3 hours to qualify as

[12] Denholm, Jorgenson, Hummon, Jenkin, Palcha, Kirby, Ma, O'Malley. The Value of Energy Storage for Grid Applications. National Renewable Energy Laboratory. NREL/TP-6A20-58465. May 2013. Available at: http://www.nrel.gov/docs/fy13osti/58465.pdf

"capacity" for the Companies' systems) but relatively infrequent use in terms of duty cycles (perhaps 50 – 100 cycles per year).

Time Shifting of Demand and Energy: Energy storage can be used to "shift" demand from one time period to another. Time shifting (also referred to as "load shifting") applications also typically require long duration (hours) of storage in order to be effective. In markets with substantial on-peak/off-peak energy price differentials, storage is valuable in financial arbitrage. In Hawai'i, there is not a large differential between the on peak and off-peak marginal cost of energy production; therefore, price arbitrage is not a primary consideration for energy storage at the grid level. Time shifting using energy storage may be useful in Hawai'i for managing the variability of some renewable energy resources, or to capture the available energy production from variable resources and store it for use at a later time, rather than "spilling" the available energy. Time shifting also requires relatively long storage durations, with the number of duty cycles being dependent on the nature of the market (for price arbitrage) or relative penetration of variable renewable energy and the frequency of curtailment events that could be avoided using energy storage.

Sub-Second Response: Fast acting energy storage can be used to supplement inertia and limit under-frequency load shedding that would occur during faults and other abnormities that occur on the grid, such as loss of generation. See Appendix E, Essential Grid Services.

Power Quality: Some energy storage devices can provide power quality and "ride-through" service. Power quality refers to the quality of the AC voltage in the system. Some energy storage devices can respond to changes in AC voltage by absorbing and releasing energy to "smooth" the sinusoidal AC waveform. For example, this type of functionality is used for some wind plants to ensure that equipment remains connected through transient system conditions.

These energy storage applications and the operational requirements associated with them are mapped in Figure J-1.

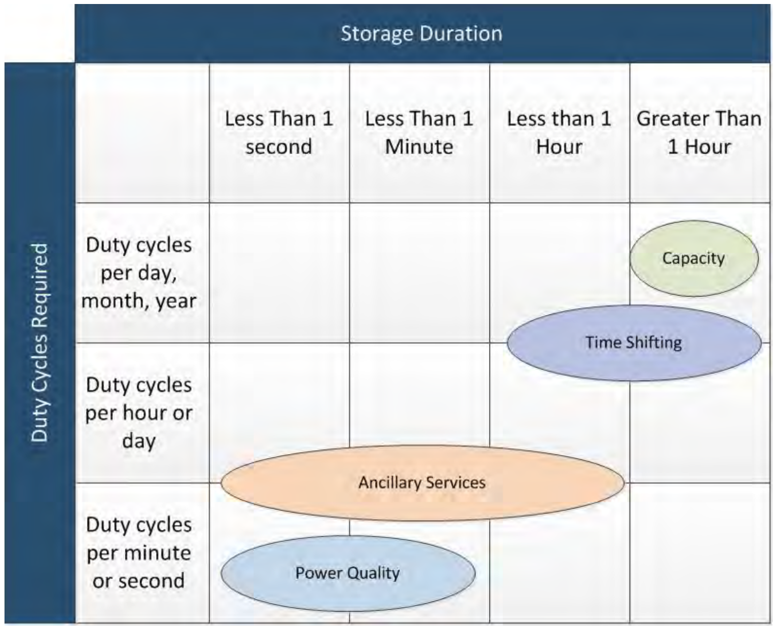

Figure J-1. Energy Storage Applications[13]

ENERGY STORAGE TECHNOLOGIES

Energy storage technologies can be categorized in terms of the physics utilized to store energy. These categories and the types of specific technologies include:

Mechanical: pumped storage hydroelectric (PSH), compressed air energy storage (CAES), flywheels. Underground CAES is not considered viable in Hawaiʻi due to lack of suitable geographic features and structural features conducive to CAES. However, aboveground CAES may be technically viable, but has not been considered at this time. PSH and flywheels are considered for Hawaiʻi and are discussed below.

Electrochemical: secondary batteries (lead-acid, lithium ion, other chemistries)[14], flow batteries. Lead-acid batteries, lithium ion and flow batteries are considered for Hawaiʻi and are discussed below.

Chemical: hydrogen (H_2), synthetic natural gas (SNG). These technologies are not considered for near-term applications in Hawaiʻi. A hydrogen infrastructure is, at best, a

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13 Adapted from International Electrotechnical Commission (IEC) Electrical Energy Storage Whitepaper, December 2011. Available at: http://www.iec.ch/whitepaper/pdf/iecWP-energystorage-LR-en.pdf

14 "Primary" batteries cannot be recharged (for example, a dry cell flashlight battery). In "Secondary" batteries, the charge/discharge cycle can be reversed, meaning that secondary batteries can be recharged.

decade away. SNG is not economically viable as the round trip efficiency in very low (about 36%)[15].

Thermal: ice storage and grid interactive water heating. Ice storage and other forms of thermal energy storage are not considered here for bulk power applications. Several companies market thermal ice storage systems for managing end-use load (typically air conditioning) against tariff price signals[16]. Thermal energy storage can be useful for implementation by end-users in response to time-based pricing programs that are part of the Companies' demand response initiative (for example, grid interactive water heating).

Electrical: ultra-capacitors, superconducting magnet. These technologies are on the cusp of commercially readiness for grid-scale applications. Ultra-capacitors are increasingly being used in power quality applications[17]. Indeed, the Hawi wind plant in the Hawai'i Electric Light system utilizes an ultra-capacitor to ensure it remains connected through grid transients.

The following subsections briefly discuss the specific energy storage technologies that have been assumed to be available for consideration in the PSIP's. The inclusion of these technologies, and the exclusion of others, does not imply that the Companies are closed to considering other technologies. Specific energy storage proposals will be evaluated on their merits, including the commercial readiness of the technology proposed, utilization in specific grid-scale applications, and other relevant factors.

Flywheels

Flywheels are mechanical devices that store energy in the angular momentum of a rotating mass. The rotating mass is typically mounted on a very low friction bearing. The energy to maintain the angular momentum of the rotating mass is supplied from the grid. During a grid event, such as a sudden loss of load, the inertia of the rotating mass provides energy to drive a generator, which provides replacement power to the grid.

Flywheels are useful to provide inertial response in a power system. They are also increasingly used in commercial applications to provide fast-response, short-term "ride-through" capability that allows seamless transfer of load from the grid to a longer-term backup system such as an emergency generator. Flywheels display excellent load following characteristics over very short duration timeframes. Thus, they are well suited for providing frequency regulation and contingency reserves.

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[15] Pascale. KU Leuven. *Energy Storage and Synthetic Natural Gas.* (undated). Available at: http://energy.sia-partners.com/files/2014/05/Paulus_Pascale_ArticleUpdated1.pdf

[16] See for example Ice Energy. http://www.ice-energy.com/

[17] Daugherty, Leonard. SolRayo. *Ultracapacitors for Renewable Energy Storage*. (undated). Available at: http://www.solrayo.com/SolRayo/Presentations_files/Ultracapacitors_for_Renewable_Energy_Storage_Webinar.pdf

The capital cost of flywheels is fairly high. However, flywheels can provide hundreds of thousands of charge/discharge cycles over their useful life. Flywheel energy storage can be developed in two years or less, not counting regulatory approval lead-times. The round trip efficiency of a flywheel storage system is approximately 85%.

Other than specific site considerations, flywheels have very little environmental impact. Modern metallurgy has produced flywheel technologies that are safe during operation. Several vendors have designs that place flywheels underground for additional safety.

Advanced Lead Acid Batteries

Lead-acid batteries were invented in the mid 19th century. Conventional lead-acid batteries are characterized by low energy density (the amount of energy stored relative to the mass of the battery), relatively high maintenance requirements, and short life cycles. Their principle advantage is the ability to deliver high current over long duration timeframes. Disposal of lead-acid batteries presents environmental considerations, but recycling techniques are well established.

Advanced lead-acid batteries or "UltraBatteries" are now reaching the market. UltraBatteries combine conventional lead-acid batteries with electronic ultra-capacitors to provide high duty cycles. The supercapacitor enhances the power and lifespan of the lead-acid battery, acting as a buffer during high-rate discharge and charge[18]. This makes the UltraBattery a low cost, durable battery technology, with faster discharge/charge rates and a life cycle that is two to three times longer than a regular lead-acid battery[19].

Like all chemical energy storage systems, capital costs for advanced lead acid batteries are still relatively high for grid-scale applications. Round trip efficiencies are also high at around 90%.

Grid-scale advanced lead acid battery projects can be developed in two years or less, not counting regulatory approval lead-times.

The high market penetration of lead-acid batteries in automotive applications has led to successful lead-acid battery recycling programs. Not only does recycling keep lead out of the waste stream, recycling supplies over 80% of the lead used in new lead-acid batteries.[20]

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[18] *UltraBattery: No Ordinary Battery*. Australian Commonwealth Scientific and Industrial Research Organisation (CISRO). Available at: http://www.csiro.au/Outcomes/Energy/Storing-renewable-energy/Ultra-Battery/Technology.aspx

[19] *Ibid.*

[20] Conger, Christine. "Are Batteries Bad for the Environment?" Discovery News. September 16, 2010. Available at: http://www.nbcnews.com/id/39214032/ns/technology_and_science-science/t/are-batteries-bad-environment/#.U_ATm-VdVS8

Lithium Ion Batteries

"Lithium-ion" refers to a wide range of chemistries all involving the transfer of lithium ions between electrodes during charge and discharge cycles of the battery[21]. Lithium ion batteries are very flexible storage devices with high energy density, a fast charge rate, a fast discharge rate, and a low self-discharge rate, making lithium ion batteries ideal for grid applications[22].

Capital costs for lithium ion batteries are declining[23], particularly as the use of lithium ion for electric vehicle batteries rises. Lithium ion batteries themselves have a useful life through 400-500 normal charge/discharge cycles. More frequent use of the full charge/discharge capabilities of lithium ion would shorten the life. Lithium ion battery energy storage can be developed in two years or less, not counting regulatory approval lead-times.

The round trip efficiency for lithium ion technology is around 90%.

Lithium ion batteries do not contain metallic lithium, nor do they contain lead, cadmium, or mercury. Thus, disposal of lithium ion batteries is not a major issue. At the end of their useful life, lithium ion batteries are dismantled and the parts are reused.[24] Overcharging certain lithium ion batteries can lead to explosive battery failure. Thus, the overall safety of lithium ion batteries in grid applications is a function of mechanical design and control systems.

Flow Redox Batteries

A flow battery is charged and discharged by a reversible reduction-oxidation ("redox") reaction between two liquid electrolytes of the battery. Unlike conventional batteries, electrolytes are stored in separated storage tanks, not in the power cell of the battery. During operation, these electrolytes are pumped through a stack of power cells, in which a chemical redox reaction takes place and electricity is produced. The design of the power cell can be optimized for the power rating needed, since this is independent of the amount of electrolyte[25].

Advantages of flow batteries include virtually unlimited cycle life and fast charge/discharge times for the electrolyte, but the power cells do require periodic replacement. Increasing the size of the electrode stack can increase the power output of a

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21 Energy Storage Association. http://energystorage.org/energy-storage/technologies/lithium-ion-li-ion-batteries

22 *Lithium Ion Technical Handbook*. Gold Peak Industries (Taiwan), Ltd. http://web.archive.org/web/20071007175038/http://www.gpbatteries.com/html/pdf/Li-ion_handbook.pdf

23 See for example: http://rameznaam.com/2013/09/25/energy-storage-gets-exponentially-cheaper-too/

24 See for example: http://auto.howstuffworks.com/fuel-efficiency/vehicles/how-green-are-automotive-lithium-ion-batteries.htm

25 This paragraph taken from: http://www.imergypower.com/products/redox-flow-battery-technology/

flow battery, and the storage capacity (energy) can be increased by increasing the size of electrolyte storage (or volume of electrolyte tanks). Flow batteries are useful for longer storage duration (hours) applications. Their relatively high capital costs make them less useful for ancillary service applications. Flow batteries are generally considered safe, an important issue for grid-scale batteries where thermal runaway of conventional batteries may cause fire[26].

Capital costs for flow batteries are still relatively high. The round trip efficiency of a flow battery is relatively low at around 72%.

Pumped Storage Hydroelectric

Pumped storage hydroelectric (PSH) is a mature technology that has been successfully implemented around the world in grid applications. In a pumped storage hydro system, water is pumped to a higher elevation using energy made available from generating resources that are otherwise unused (for example, low marginal cost off-peak energy or excess renewable energy that would otherwise be curtailed, etc.). During high demand periods, this stored water drives a hydroelectric pump-turbine to generate electricity.

Pumped storage hydroelectric has a relatively high capital cost, but has a useful life typically in excess of 50 years. Pumped storage is very efficient with round trip efficiencies approaching 80%.

Pumped storage hydro installations are very site dependent. Pumped storage investigations in Hawai'i have previously identified several potential sites in the Companies' service territories, with available output capacities typically less than 100 MW in size. Pumped storage hydro installations also face substantial siting and permitting challenges, particular where new reservoirs must be constructed and subsequently flooded. Because of the site specific challenges and the substantial engineering and construction efforts required to build a PSH project, the typical development time for pumped storage is seven years or longer, posing challenges to the utility planner, particularly in an environment where the need to deliver solutions in the near term is paramount.

Due to the inherent economies of scale, the preponderance of pumped storage hydroelectric installations in the United States are typically hundreds or even thousands of megawatts in size. There is very limited data on capital cost and performance for operating pumped storage hydroelectric installations that are less than 100 MW in size.

Pumped storage hydro is a very useful technology for providing peaking capacity and time shifting capabilities. While pumped storage hydro is a quick-start resource, the

[26] Lamonaca, Martin. "Startup EnerVault Rethinks Flow Battery Chemistry." MIT Technology Review. March 22, 2013.

water column constant of a typical pumped storage system is about 7 seconds (that is, this is the time it takes to get the water moving through the turbine to produce electricity). This is a limiting factor with respect to the utilization of an off-line pumped storage system for providing certain ancillary services. The utilization of adjustable speed pump turbine technology in pumped storage hydroelectric projects can provide operating flexibility compared to conventional pump turbines. The main advantage of using adjustable speed technology is the ability to provide more precise power control. This power control can be maintained over a wider operating range of the pumped storage hydroelectric system, allowing the utility to provide ancillary services, such as frequency regulation, spinning reserve, and load following, in both the generation and pumping modes. These benefits and other attributes of an adjustable speed pump turbine can translate into increased operating efficiencies, improved dynamic behavior, and lower operating costs.

Unlike a battery, which already has charge, or a flywheel that has angular momentum, the start of a pumped storage charging cycle requires the delivery of high levels of electric current to start the motors necessary to pump water to the higher elevation. To put this in perspective, a 30 MW pumped storage system in the Hawaiʻi Electric Light system would require staring 37.5 MW of motor load (assuming an 80% round trip efficiency). The typical daily peak demand of the Hawaiʻi Electric Light system is about 150 MW. Therefore, the start of the motor would represent an instantaneous load increase of 25% on the system. This may result in currents that exceed the short circuit limits of the transmission system, and without mitigation this would result in a significant frequency disturbance.

The primary environmental impacts from pumped storage hydro occur during construction. If construction of new reservoirs and/or water diversion is required, this can lead to substantial permitting challenges.

ECONOMICS OF ENERGY STORAGE

Energy Storage Capital Cost

The costs assumed in the PSIP's for energy storage systems are generally based on actual proposals for energy storage systems and flywheels, and from a combination of sources for pumped storage hydroelectric. The cost of energy storage for any given storage technology is in part a function of the duration of storage required. Table J-1 summarizes the capital costs assumed for the PSIP's mapped against the specific grid services required in the Companies' systems[27].

Grid Service	Technology					
	Storage Duration / Discharge	Flywheel $/KW	Advanced Lead Acid $/KW	Lithium Ion $/KW	Flow Redox $/KW	PSH $/KW
Inertial, Fast Response Reserves	0.05 min / 5000 cycles per year	$997	NA	NA	NA	*
Regulating Reserves	30 min / 1000 cycles per year	$4,459	$1,005	$1,179	$1,596	*
Contingency Reserves	30 min / 20 cycles per year	$2,263	$802	$942	$1,079	*
Capacity, Long-term Reserves	> 3 hours / 50 cycles per year	NA	$4,531	$5,401	$2,559	$4,500[28]

Costs include EPC, land, and overheads. Costs do not include AFUDC. NA = not economic, or unable to provide this service. * PSH may be able to provide these services when operating, but because the upper reservoir capacity of a given pumped storage project site is defined by geology and other factors, PSH would not typically be economical to build for the sole purpose of providing very short duration services.

Table J-1. Energy Storage Technology Capital Cost Assumptions (2015 Overnight $/KW)

Energy Storage Fixed O&M

The PSIP fixed O&M cost assumptions for energy storage were also based on actual proposals, except for pumped storage hydroelectric, which is based on NREL data. Table J-2 summarizes the storage fixed O&M costs.

Grid Service	Technology					
	Storage Duration / Discharge	Flywheel	Advanced Lead Acid	Lithium Ion	Flow Redox	PSH
Inertial, Fast Response Reserves	0.05 min / 5000 cycles per year	58	NA	NA	NA	NA
Regulating Reserves*	30 min / 1000 cycles per year	264	31	32	43	NA
Contingency Reserves	30 min / 20 cycles per year	108	25	27	29	NA
Capacity, Long-term Reserves	> 3 hours / 50 cycles per year	NA	90	105	62	29

Table J-2. Energy Storage Fixed O&M Assumptions (2015 $/KW-Year)

[27] See Appendix E for a discussion of Essential Grid Services in the Companies' systems.

[28] There is relatively little actual data available regarding the cost of utility-scale pumped storage projects less than 100 MW in size. This capital cost assumption for pumped storage used in the PSIP analyses was determined though evaluation of a number of different sources, including a review of confidential screening-level cost estimates for site specific projects in Hawai'i, estimates for a 50 MW pumped storage project in the United Kingdom, NREL data, U.S. Energy Information Administration data, and conversations with a potential pumped storage developer in Hawai'i.

Energy Storage Variable O&M

The PSIP variable O&M cost assumptions for energy storage were also based on actual proposals, except for pumped storage hydroelectric O&M, which is based on NREL data. The variable O&M costs for batteries is solely related to battery and cell replacements and disposal at the end of the duty cycle of the batteries which are assumed to require replacement due to high number of charge/discharge cycles per year associated with provision of regulating reserves. Table J-3 summarizes the storage variable O&M costs

Grid Service	Storage Duration / Discharge	Technology				
		Flywheel	Advanced Lead Acid	Lithium Ion	Flow Redox	PSH
Inertial, Fast Response Reserves	0.05 min / 5000 cycles per year	NA	NA	NA	NA	NA
Regulating Reserves*	30 min / 1000 cycles per year	-0-	88	45	30	NA
Contingency Reserves	30 min / 20 cycles per year	NA	NA	NA	NA	NA
Capacity, Long-term Reserves	> 3 hours / 50 cycles per year	NA	NA	NA	NA	59

Table J-3. Energy Storage Variable O&M Cost Assumptions (2015 $/MWH)

Benefits of Energy Storage

In the Companies' systems, energy storage can be used for several purposes.

- Capacity to serve load
- Manage curtailment of variable renewable generation
- Ancillary services
- Integration of renewables

Benefits of energy storage for each of the above uses depend upon specific operating conditions, the capacity adequacy situation in each of the operating systems, and the other resource options available. In general, energy storage can also be used for multiple purposes. For example, energy storage installed to provide capacity to serve load, could also be available to provide ancillary services, provided it is not being used in its load-serving mode. However, if the storage asset is will be used for multiple purposes, it must be designed to ensure the energy allocation and response capability can serve the combined needs. For example, storage used for contingency reserves must be kept at the necessary charge level to provide the required reserve. If also providing regulation, additional energy storage capacity would be required above the minimum required to meet the contingency reserve requirement.

Capacity

Energy storage can provide capacity to serve load on the Companies' systems, provided that there is a need for capacity[29] and provided that there is the appropriate duration of energy storage available to qualify as capacity[30]. During the PSIP planning period, the Hawaiian Electric and Maui Electric systems are expected to add capacity to replace retiring generation. Thus, energy storage is one of the alternatives that must be considered for providing that capacity.

Figure J-2 conceptually depicts the economic comparison of energy storage to generation for providing capacity.

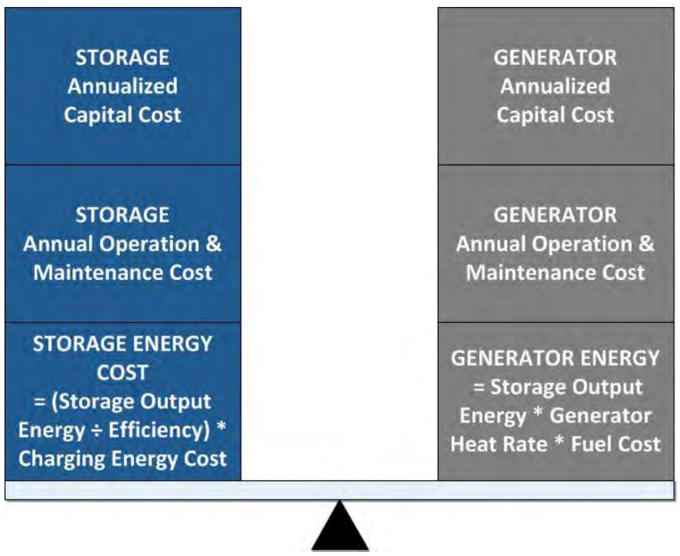


Figure J-2. Energy Storage Economics for Capacity

In this comparison, the energy storage device is compared on a one-for-one basis as a substitute for a generator. A levelized utility revenue requirements factor is applied to the total capital cost of the storage and the generator to determine the annual capital costs. The O&M costs associated with the two alternatives are determined. And finally, the cost of the energy output from each of the assets is computed. In the case of the storage technology, the round trip efficiency must be taken into account, because more energy is required to charge the energy storage asset than is usefully delivered from the same energy storage asset. If the total cost of the energy storage asset were less than the cost of the generator, energy storage would be the most economical alternative[31]. Note that in the case where capacity is not needed, the capacity cost of the generator would be

[29] Denholm, Jorgenson et. al.

[30] Storage is a finite energy resource. When used as a capacity resource, the storage must be carefully designed for the appropriate duration, and the storage energy must be utilized in an appropriate manner. The Companies' criteria require that a resource be able to deliver energy for 3 continuous hours in order to qualify as capacity.

[31] In a proper analysis, any differences in ancillary service costs or benefits associated with the alternatives being compared will also be included.

zero, because existing generation (whose capital cost is sunk) would be able to provide amount of energy required by the system.

Managing Curtailment

Energy storage used to manage variable renewable energy curtailment is an example of a time shifting application for storage, and may have use in the Companies' systems. Energy storage can absorb variable renewable energy that is produced when it is not needed, and return that energy (less round trip losses) to the system at a later time. Figure J-3 conceptually depicts the economics of energy storage in managing curtailment.

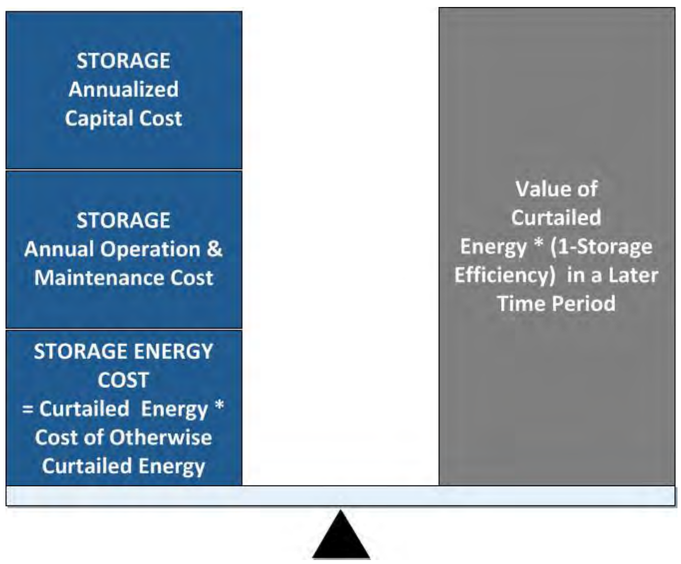


Figure J-3. Energy Storage Economics for Managing Curtailment

The basic economic equation in Figure J-2 is a comparison of the cost of the energy storage versus the value of energy in a later time period of energy that would have otherwise been curtailed (less the round trip efficiency losses since that those losses will not be returned to the system). Note that in Figure J-2 there is a cost associated with the curtailed energy used to charge the energy storage device. Absent the energy storage asset, the payment for the curtailed energy would have been avoided. Thus, this is a cost that is borne by the ratepayer that would otherwise have not been incurred. Further study of Figure J-2 will reveal that the cost comparison includes the capital cost of the energy storage, but it does not explicitly include any capacity value (that is, capital cost) associated with use of the energy in a later time period. Unless there are severe capacity constraints in the system where new capacity is required, the capacity value of the energy used at a later time is essentially zero. At current Company system marginal cost levels, it would almost never be economical to build energy storage exclusively for the purpose of managing energy curtailment. Rather, it is more likely that an energy storage asset already installed for another purpose could also be used to manage curtailment.

Ancillary Services

Energy storage can be used to provide ancillary services, provided that it can respond in the time frames necessary and operate in a coordinated fashion with other generation and demand response resources on the system. Using energy storage to provide ancillary services slightly increases total amount of energy that must be generated in the system due to the round trip losses associated with the energy storage asset. The charging energy may come from thermal resources or from variable renewable resources. However, energy storage may allow energy production costs to be reduced if provision of ancillary services is causing a constraint on the economic commitment and dispatch of generating units. These economics are depicted in Figure J-4.

The value of the energy storage asset in this situation is based on production cost savings (fuel and O&M) that are incurred by storage supplying the ancillary services. Calculation of these benefits requires production simulations.

If capacity is required in the system, short duration energy storage may be more cost effective than adding new generating capacity. If that is the case, the capital cost of the new generation must be added into the benefits that storage can provide.

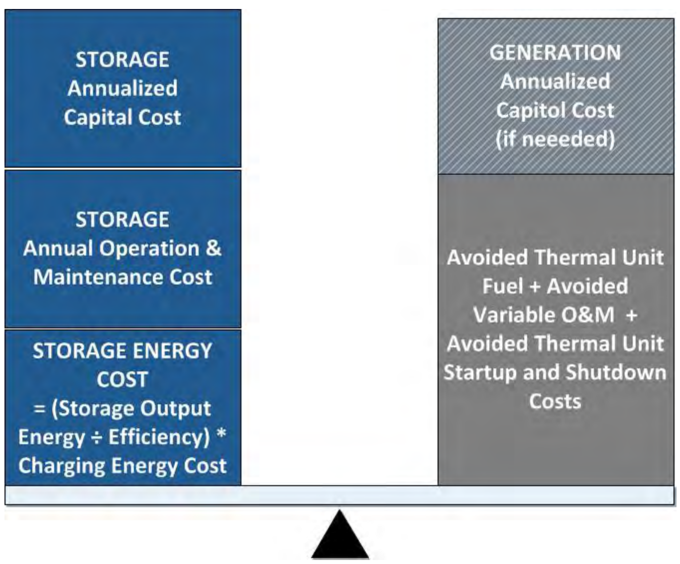


Figure J-4. Energy Storage Economics for Ancillary Services

Integration of Renewables

Another possible use of energy storage in conjunction with renewable energy is to combine the installation of a variable renewable generator with the installation of energy storage. This has been accomplished in the all three of the Companies' main operating systems. The value of this configuration for customers is that it essentially allows the storage to be leveraged to minimize the ancillary service requirements created by the variable generator that would otherwise have to be provided by other resources on the system. Location of storage at the plant allows the sizing to be designed for the plant needs; co-location also simplifies the communications control interface. From a system standpoint, the storage/generation combination is treated as a plant with the combined operational/technical capabilities of the turbines and storage. The economic evaluation is essentially the same as that portrayed for ancillary services in Figure J-4.

It should be noted that in several cases, the installation of the energy storage was feasible only because it was bundled with generation in a way that allowed the project developer to obtain tax advantages for the energy storage that would not be available for a standalone energy storage asset. In other words, energy storage added value to the generation.

Unless marginal thermal generation costs were much higher than they are today, the converse is not true (that is, adding generation does not add value to storage). It does not make economic sense to build excess renewable generators exclusively to provide energy to charge storage assets since in doing so, the marginal capital cost would be the sum of the generator capital cost and the storage capital cost. Rather, it is important that the system be planned to optimize all resources, including generation, demand response, and storage to achieve the lowest cost.

K. Capital Investments

This information represents the 2015–2030 capital expenditure budget for the Hawai'i Electric Light Company.

TRANSFORMATIONAL INVESTMENTS

The transformation of the Hawai'i Island electric power system and grid is being made to cost effectively enable more renewable generation while maintaining the reliability of the grid system. This requires significant investment in virtually every aspect of the business. Investments include new renewable generation resources, installing enabling technologies for demand side resources and DGPV requiring grid reinforcements. Additionally modifications to infrastructure for lower-cost LNG fuel will transform our Island grid reducing the cost to the customer while maintaining grid reliability. These transformative investments are described below more in depth.

Liquefied Natural Gas (LNG)

In an effort to reduce customer costs, Hawai'i Electric Light is pursuing two non-exclusive approaches to import lower-cost LNG to Hawai'i: importation of LNG via ISO (International Organization for Standardization) containers (containerized LNG); and/or importation of LNG via bulk LNG carriers (bulk LNG). Hawai'i Electric Light will receive containers from O'ahu and the supplier will truck the containers to the three (3) sites currently planned for LNG conversion.

The concept of containerized LNG would involve using conventional container ships and trucks equipped to handle ISO containers. The LNG ISO containers would be delivered directly to the generating stations where the LNG would be regasified and consumed.

Shipping and distribution of containerized LNG to Hawaiʻi in volumes sufficient for power generation may possibly be commercialized within three years or less.

The bulk LNG concept would involve transporting LNG across the ocean via LNG carriers and/or articulated tug barges, and receiving it at a bulk LNG import. The bulk system will be designed with a transfer system to load containers for the continued transportation to the Hawaiʻi Electric Light facilities thru the normal barge and truck transportation chain. It is anticipated that development, permitting, and implementation of a bulk LNG import and containerization facility will take up to eight years to complete, and could possibly be placed in service in 2020 to 2022.

Regarding containerized LNG, Hawaiʻi Electric solicited offers from third parties for containerized LNG deliveries via a March 11, 2014 request for proposals ("RFP") and final bids from three potential suppliers were received on May 24, 2014. The responses to the RFP indicate that containerized LNG could be delivered to generating stations on Oʻahu and neighbor islands up to an approximate 30% discount below current petroleum fuel prices. Based on these proposals, Hawaiʻi Electric Light intends to move forward as quickly as it can to bring containerized LNG to Hawaiʻi and to use it in existing and future replacement generating units.

It appears that importing containerized LNG will have the potential of saving the Companies' customers throughout the state substantial amounts on fuel costs. The amount of the savings will depend on the prices for the fuels that are displaced once LNG is available, and the final prices from the on-going RFP. It is uncertain at this time whether a bulk LNG delivery solution would provide as much, the same or more of a cost benefit to customers. Therefore, Hawaiian Electric will continue to pursue the bulk LNG concept as long as there is a potential that it will provide additional benefits and value to our customers.

System Security Investments

To reliably operate a grid rich in variable renewable generation requires the grid operator to manage a new, and to some extent not fully known, set of electrical system security issues. When such a grid is a small islanded system such as Hawaiʻi Island, the criticality of these issues is further heightened, as compared to the large, interconnected grids of North America. The Company's system security analyses, coupled with the PSIP planning processes, have defined a number of new investments required to meet these system security challenges. These investments, "Energy Storage – Contingency Reserve" and "Energy Storage Regulating Reserve," enable the Company to comply with its system security and reliability standards by 2016 and maintain compliance with these standards through the remainder of the study period.

Investments also include telecommunications infrastructure additions to provide SCADA functionality to all distribution substations. SCADA provides for information and control of distribution substation devices for improved reliability and situational awareness. It also provides the communication link to communicate with utility and customer equipment located within and connected to distribution circuits. These include communications to facilitate dynamic under frequency load shedding; provides a “backhaul” for Distribution Automation, AMI, and other Smart Grid technologies; and is a necessary communications link to take advantage of “smart” inverter capabilities, including inverter status, voltage regulation, active inverter control/regulation, and other functionality as described in the DGIP.

Additionally, investments will also include a new Energy Management System (EMS) to replace the current EMS when it reaches the end of its product lifecycles and to take advantage of state-of-the-art hardware and software technologies to properly operate a grid with significantly more monitoring and control points than in the past and to allow for the coordinated operation of the system – both automatic generator controls and T&D switching—and also to interface with the Advanced Distribution Management System (ADMS) and Outage Management System (OMS) planned to allow for coordination with circuit/area-level grid operations such as DR, DA, DG, EV and operations and monitoring of other DERs.

Facilitation of New or Renewable Energy

Additional transmission system infrastructure will be required for the addition of several new renewable energy suppliers. A substation and transmission line interconnection will be required to add a new 25MW Geothermal generating plant in the West Hawai‘i region in 2025

Additional transmission system infrastructure will be required in the addition of a substation and transmission line interconnection will be required to add a new 20MW Wind generating plant in 2020.

Additional transmission system infrastructure will be required in the addition of a substation and transmission line interconnection will be required to add new 5MW and 20MW battery storage systems in 2017.

The growth of DGPV has prompted a need to ensure fast fault clearing times on the transmission system. The need for fast clearing times is the result of a system dynamics study with the projected DGPV growth that indicated that at the current levels of DGPV the grid will become unstable in the event of a significant fault or loss of a generating unit while there is heavy PV generation. Under normal conditions, the required clearing time is met by existing equipment. However, a failure of one or more pieces of the transmission relay and breaker equipment during a fault can lead to a long clearing time and unstable event. The solutions to reduce the fault clearing time significantly during this contingency include replacing slower clearing circuit breakers, adding breaker failure protection and adding redundancy to the relay communication. Projects to address this are planned over the next 5 years.

DG Enabling Investments

The Distributed Generation Improvement Plan (DGIP) lays out an aggressive plan to enable the integration of significant amounts of new distributed resources, which are expected to be primarily rooftop PV.

The DGIP includes a Distribution Circuit Improvement Implementation Plan (DCIIP) that summarizes specific strategies and action plans, including associated costs and schedules, for circuit upgrades and other mitigation measures to increase the capacity of the Companies' electrical grids and enable the interconnection of additional DG.

In evaluating each company, by circuit and substation transformer, improvements to allow for greater interconnection of DG include: (1) updating LTC and voltage regulator controls to be capable of operating properly under reverse-flow conditions; (2) upgrading substation transformer capacity when load and DG are greater than 50% of capacity in the reverse direction; (3) upgrading primary circuit capacity when load and DG are greater than 50% of capacity in the reverse direction; (4) upgrading customer service transformer capacity when load and DG are greater than 100% of capacity, which also mitigates high voltage; (5) adding a grounding transformer to circuits when 33% of DML is exceeded for applicable circuits; and (6) adding a grounding transformer of 46-kV lines when 50% DML is exceeded. Each of these mitigation measures provides different values to both the utility and the distributed PV owner.

Smart Grid and Demand Response

At the Hawaiʻi Electric Light Companies, we are committed to achieving modern and fully integrated electric grids on each of the islands we serve—grids that harness advances in networking and information technology and, as a result, deliver tangible benefits to our customers and the state of Hawaiʻi. To accomplish this, we plan to invest in smart grid.

Two-Way Communications System

The backbone of our Telecom System (fully owned by the Hawaiʻi Electric Light Companies) acts as an enabler for all of our operational and corporate business applications, including the smart grid applications. The Hawaiʻi Electric Light

Companies enterprise telecommunications network or backbone is commonly referred to as our Wide Area Network (WAN) and Field Area Network (FAN). The smart grid applications and end devices (such as the smart meters), fault circuit indicators (FCIs), SCADA-enabled distribution line transformers and switches, reside in the Neighborhood Area Network (NAN), which is located beyond the WAN and FAN networks. The foundation of the smart grid platform (the NAN) we intend to implement is a two way communications network that connects points along the distribution grid to our back office software. Smart grid applications run on that network providing detailed information about the performance of the distribution grid.

AMI uses the secure IPv6 network that employs wireless 900MHz radio frequency mesh technology. This wireless technology consists of: access points; routers enabling devices communicating over the radio frequency mesh network to connect to our IT infrastructure through wired or cellular connections; relays, which are repeater devices that extend the reach of the radio frequency signal; and intelligent endpoints (such as third-party smart meters outfitted with network interface cards from Silver Spring Networks).

All Silver Spring Networks devices contain a one watt, two way radio. These devices connect with each other to form a mesh that makes up the Neighborhood Area Network (NAN). Access points and relays will be designed to have multiple paths through the NAN and the utility's WAN to provide high-performance, redundant connections between endpoints and our back office systems and data center. The network interface cards inside smart meters also act as relays (repeaters), further extending the mesh.

The radio frequency mesh network aggregates smart meter data and transmits it to us either through the utility-owned WAN or cellular connection. The mesh network can also transmit other information (such as remote service connects or disconnects) from us to customers. A back office head end system (such as Utility) collects, measures, and analyzes energy consumption, interval and time-of-use data, power quality measures, status logs and other metering data, and manages smart grid devices. Other back office systems manage meter data and integrate that data with customer and billing information.

Customer Engagement

Hawai'i Electric Light believes in a proactive, transparent and sustained communication effort to educate and engage our customers is critical to successfully rolling out the Initial Phase, the initial step in our smart grid plans. Our efforts to engage our customers underscore our commitment to continually improve customer service, modernize the grid, and integrate renewable energy.

We intend to inform customers about installing smart meters, educate them about smart grid benefits, and address their related concerns. Key to this is helping customers understand that, at its core; smart grid technology will offer them more information about their energy use than ever before and give them tools and programs to help them control their energy use, which they can then use to help lower their electricity bills.

Through a multi-pronged approach for the duration of our smart grid roadmap, we intend to build interest from the onset, address questions and concerns, and engage customers in understanding the benefits of smart grid. Our communication program is based on tested and proven industry best practices, and is customized based on research conducted in this market on how to best reach our customers. Our approach seeks to engage our customers with information tailored to their specific needs and questions. Working with trusted third-party groups, we plan to engage customers in direct conversations wherever they are—at home, in their neighborhoods, and online.

Replacement Dispatchable Generation Capacity

New Generation

The Commission provided Hawai'i Electric Light explicit guidance to expeditiously "modernize the generation system to achieve a future with high penetrations of renewable resources." Decision and Order No. 32052, filed April 28, 2014, in Docket No. 2012-0036 (Regarding Integrated Resource Planning), Exhibit A: Commission's Inclinations on the Future of Hawai'i's Electric Utilities (*Commission's Inclinations*) at 4. The Commission recognized that act of "serving load" at all times of the day is becoming less focused on energy provision, and more focused on providing or ensuring the reliability of the grid. Proposed New Generation projects would be a firm generation resource with attributes and optionality consistent with this guidance, including the following abilities:

- Start, synchronize to the grid, and ramp to full load in a few minutes;
- Ramp generation output up and down at fast rates for frequency regulation;
- Operate over a very wide range of loads when synchronized to the gird (that is, more than 12 to 1 turndown);
- Execute multiple starts and stops throughout any operating period;
- Control Volt-Amp Reactive ("VAR") output for voltage regulation;
- Provide an automatic inertial response during major grid contingencies to help stabilize system frequency;
- Efficiently convert fuels to electric power (that is, to operate at low heat rates) over its full range of power output;

- Utilize multiple liquid and gaseous fuels; and
- Black start and "island a defined energy district" at a unique location in central O'ahu, adjacent to a major air field.

These attributes will contribute to maintain grid stability, security, and resiliency as more variable renewable generation is interconnected.

Retirement of Existing Generation Assets

We will aggressively pursue the retirement and replacement of existing generating units. We "deactivated" Shipman Unit 3&4 in 2012. These units are scheduled to be decommissioned in 2015. The deactivation and retirement of these units allows us to focus our existing resources on our existing units.

We intend to further retire/deactivate steam generating units as new generation and load situations allow. An aggressive plan for deactivation was created and can be adjusted as situations dictate. The plan includes deactivation of all steam units on a systematic basis. In order to provide best value to the customer in terms of cost reduction it was deemed necessary to retire units as a pair.

The Puna oil fired plant was placed in cycling mode in mid-2014 and is only operated when there is a need for capacity. This will occur when several other generators are off line for maintenance or overhaul. It is scheduled to be deactivated in 2018 and decommissioned in 2020.

The Hill unit 5 oil fired unit is scheduled for deactivation in 2020 and decommissioning in 2022.

The Hill unit 6 oil fired unit is scheduled for deactivation in 2022 and decommissioning in 2024.

The need for this unit is reduced as lower cost generation is added to the system with the Biomass addition, wind addition and geothermal additional generation. The addition of these new low cost generators will reduce the cost to our customers as well as replace the grid stability support lost by the retirement of the three(23) steam units.

Units that are scheduled to be deactivated will require capital additions in order to prepare them for deactivation. This allows reactivation should it be required. The plans are very specific and be strictly adhered to in order to be in compliance with the environmental operating permits and regulations.

Use of the Puna and Hill power plant sites after the existing units have been retired is very difficult to predict at this time. No current plans exist for the reuse of these sites; however they are possible locations for the Battery storage locations

FOUNDATIONAL INVESTMENTS

The success of the transformational investments discussed above is dependent on a strong foundation. The Company must continue to deliver safe, reliable, and efficient service to all customers. The foundational investments required to sustain operations are described below.

Asset Management

The asset management category includes costs for the replacement of substation equipment, vaults, conductor, switchgear, switches, and batteries. Asset management principles aim to minimize corrective replacement costs, for both O&M expense and capital, by implementing preventive strategies. Work performed on a planned basis, in the normal course of business, can usually be executed at lower, more predictable overall costs and with greater degree of safety to Company employees and the public.

Reliability

The Reliability category consists of production and transmission and distribution capital projects to ensure that the Company's existing generation assets and transmission and distribution grids are available to reliably generate and deliver power to customers. Major projects in this category include overhauls for existing generation assets and the reconductoring and relocation of existing transmission facilities.

Safety, Security and Environmental

The Safety, Security, and Environmental category consists primarily of distribution capital projects and programs to replace and/or relocate poles and transformers to minimize risks to the public and the Company's employees.

Customer Connections

The Company will need to connect new customers throughout the 2015–2030 periods. This work includes preparing the design and packaging of customer-requested work, such as overhead and underground services to new and existing customers along with related overhead and underground additions for construction and/or meter installations actually doing the work.

Customer Projects

The Company will need to complete customer projects throughout the 2015 – 2030 period.

This category of work includes preparing the design and relocations of services to existing customers for both overhead and underground services. The projects included in this category fall under the baseline category. Note -Fully Funded Customer Projects will not appear since numbers are net of CIAC.

Enterprise

Overview of IT Capital Programs and Enterprise Information Systems

The IT related Capital projects and programs projected in the 2015-2030 Capital forecast consists primarily of two categories:

1. IT Capital programs that support the Companies' hardware lifecycle and growth, broken down by IT function or IT service.
2. Enterprise Information Systems based on the Companies' Enterprise Information Systems (EIS) Roadmap (filed with the commission on 6/13/2014), which includes new software implementations, replacements and upgrades.

This document provides a high level overview of each category and their respective project and programs and the following table provides a view of the projects and programs over the specified timeline.

IT Programs

The ITS Department's capital budget consists primarily of IT hardware programs: (1) that maintain and enhance Hawai'i Electric Light's data center and network infrastructure; and (2) to provide the workforce with assets that support employee productivity and communications.

IT Programs	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
IT Infrastructure	$3,083,983	$2,888,867	$2,966,061	$3,112,288	$3,265,724	$3,426,724	$3,595,661	$3,772,927	$3,958,933	$4,154,108	$4,358,906	$4,573,800	$4,799,288	$5,035,893	$5,284,162	$5,544,671
Client Computing	$2,570,982	$2,248,536	$2,353,297	$2,469,314	$2,591,051	$2,718,790	$2,852,826	$2,993,471	$3,141,049	$3,295,903	$3,458,391	$3,628,889	$3,807,793	$3,995,518	$4,192,497	$4,399,187
Copiers/printers	$573,410	$831,271	$675,059	$708,339	$743,261	$779,903	$818,353	$858,697	$901,031	$945,452	$992,063	$1,040,971	$1,092,291	$1,146,141	$1,202,646	$1,261,936
ERP/CIS Hardware Upgrade	$0	$0	$0	$161,000	$1,935,000	$1,891,000	$1,620,000	$320,000	$320,000	$320,000	$2,087,000	$2,052,000	$1,781,000	$481,000	$481,000	$481,000
Collaborative communications	$671,083	$375,998	$405,104	$425,076	$446,032	$468,021	$491,095	$515,306	$540,710	$567,367	$595,339	$624,689	$655,486	$687,801	$721,710	$757,290
MISC Telephone Equipment	$506,256	$405,437	$406,960	$427,023	$448,075	$470,165	$493,344	$517,666	$543,187	$569,966	$598,066	$627,550	$658,488	$690,952	$725,016	$760,759
MISC Office Equipment	$90,826	$102,096	$383,445	$402,348	$422,184	$442,998	$464,838	$487,754	$511,801	$537,032	$563,508	$591,289	$620,439	$651,027	$683,123	$716,801

Table K-1. IT Programs Investments 2015–2030

These programs are needed to maintain and improve upon IT service levels to both Company stakeholders as well as customers through the lifecycle replacement of hardware assets. In addition, the programs account for increased demand for reliable and secure access to information and information technology, primarily driven by (1) employee and facilities growth; (2) increased investment in mobile computing; (3)

escalating need for cyber security and privacy; (4) increased need for enterprise content management; and (5) improved disaster recovery and reliability.

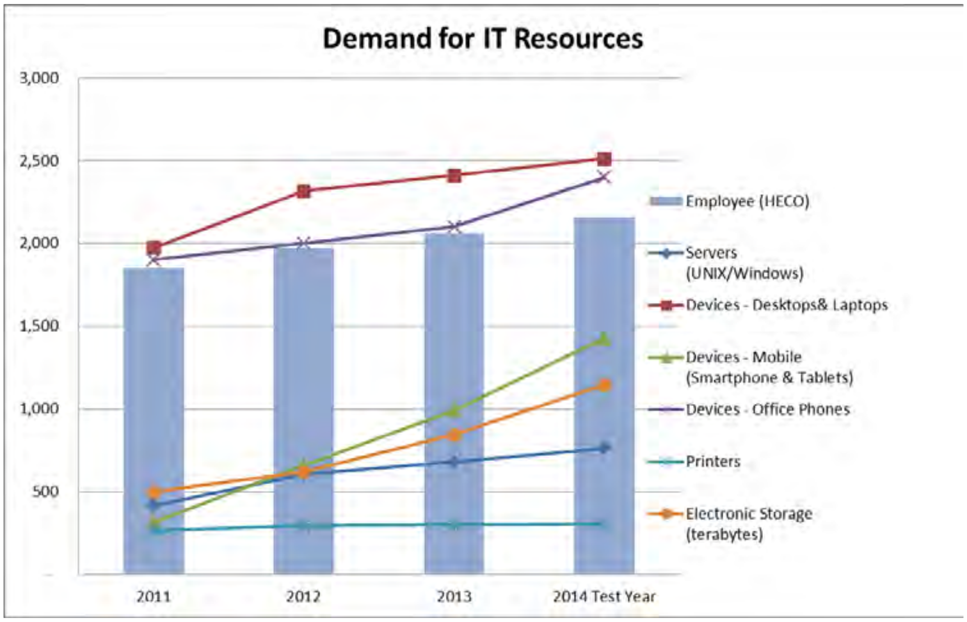


Figure K-1. Demand for IT Resources

A brief description of each of the IT programs is provided below.

IT Infrastructure program: The IT Infrastructure program is needed to maintain and enhance Hawai'i Electric Light's data center and network infrastructure and includes costs to lifecycle the server fleet, networking equipment (routers and switches), and electronic storage, as required to meet the Company's business needs. The IT infrastructure program includes "ERP/CIS Hardware Upgrade" 2018-2030 costs (shown separately as an adjustment above for the purposes of this forecast) to accommodate projected replacement and growth specifically for Enterprise Server hardware needs.

Client computing program: The Client Computing program is needed to provide the workforce with devices and other assets that are managed as part of the client computing environment and support employee productivity and communications. It includes costs to accommodate growth and lifecycle of that environment; including desktop PCs, laptops, mobile devices, and peripherals.

Collaborative Communications program: The Collaborative Communications program includes cost for those hardware assets that enable cost-effective communication and collaboration across time and distance. Specific examples include conferencing enabled telephones, projectors, electronic whiteboards, video conferencing devices, displays, digital signage equipment, microphones and public address ("PA") equipment.

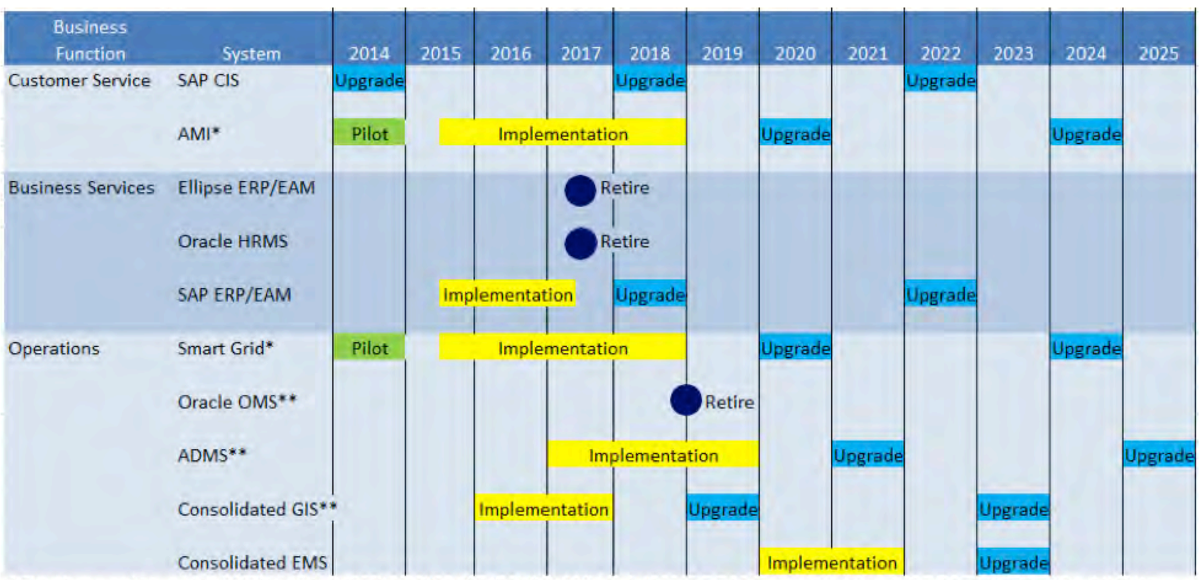
Copiers/Printers: The Copiers/Printers program includes costs to maintain, lifecycle replace, and net new additions for equipment that support the Company's printing and imaging needs. This includes desktop, multi-function, and wide-format printing devices, as well as imaging, scanning and fax devices.

(Miscellaneous) Telephone Equipment: The Telephone equipment program includes costs related to lifecycle and growth of the Company's telephone system including the PBX system, related telephony equipment, and office VOIP and digital phones.

(Miscellaneous) Office Equipment: The Office Equipment program includes costs for lifecycle replacement and installation of new equipment that support the Company mailing operations and general office equipment. Examples include the Company's mail inserter and folding machines used for billing purposes.

Enterprise Information Systems (EIS) Implementation and Upgrade Projects

EIS projects provided in this forecast include projects based on the EIS Roadmap, filed with the commission on 6/13/14.



* This document separates AMI from Smart Grid to reflect the fact that AMI provides customer consumption to customers and to the CIS, while the Smart Grid functions provide Operational capabilities.

** A study is underway to evalute an OMS upgrade or replacement with an ADMS. This document assumes OMS will be replaced by an ADMS. The study also evaluates GIS consolidation and standardizization. This document assumes GIS consolidation. Additional phases for the ADMS and GIS will be added as they are better defined.

Figure K-2. EIS Implementation Plan

The EIS implementation and upgrade projects projected within the Capital forecast are based on the EIS Roadmap with minor adjustments to accommodate the capital forecasting process and adjustment for recent developments. These adjustments include:

- Projected business releases within the overall GIS and ADMS projects.

- The inclusion of a Demand Response Management System project.
- The projection of upgrades through the additional 5 years of the forecast, not accounted for in the EIS roadmap, based on a 4 year average Enterprise Software upgrade cycle.
- The "future software implementations" for years 2023 - 30 are based on average spend of years 2015-2022.
- Smart Grid and AMI explanations will be provided separately, by the Smart Grid project team.

For the purpose of this overview these projects can be viewed in two categories: EIS projects and EIS upgrades. For a more detailed explanation of strategic and other drivers please reference the EIS roadmap. The following overviews are broken out between EIS implementation projects and upgrades.

EIS implementation Projects

ERP/EAM Project: The ERP/EAM project is a major current initiative in the Business Services area of our EIS Roadmap. For a detailed explanation of this project, please reference Dockets 2013-0007 and 2014-0170. The main goals of this effort are to address:

- **Technical Risk:** Replace Ellipse and many workgroup systems with an integrated modern solution. The currently installed Ellipse software and platform is technically obsolete, and continued use of the current version of Ellipse exposes the Companies to rapidly increasing levels of operating risk due to the technical obsolescence of the application software, system software and hardware on which it is dependent. Beyond 2017, there is a significant risk that the Ellipse system will become unsupportable.
- **Vendor Risk:** Implement a solution that is well supported within the utility industry today and into the foreseeable future. There is concern with the long-term vendor commitment to Ellipse. The newest version of Ellipse does not provide the level of electric utility-specific functionality necessary to meet the Companies' key current and future business challenges and opportunities.
- **Business Improvements:** Take the opportunity to improve business processes that increases productivity, efficiency and effectiveness.

EGIS Project: The Geographic Information System (GIS) provides the location of electrical facilities (poles, conductors, transformers, substations, etc.) on a map. It also stores information on how these facilities are connected together to make up the electrical grid. This allows for circuit tracing and allows for the export of this model to other applications such as the Outage Management System (OMS) for outage management and SynerGEE for power flow analysis. This project will migrate from the current multiple instances of different GIS platforms to a single Enterprise GIS solution, across all three companies. This effort includes cleansing and improving the accuracy of the location of electrical facilities.

ADMS Project: The Advanced Distribution Management System (ADMS) project will upgrade and expand the functionality of the current Hawaiian Electric's Outage Management System (OMS) which is used to determine and track electrical outages and deploys this system to across the three companies. An ADMS is comprised of three foundational features: Outage Management used to track and simulate outages; SCADA integration for receiving status and sending commands to the devices in the electrical grid; and Distribution Management System (DMS) which monitors and controls switching at the distribution level in conjunction with Distribution Automation.

Demand Response Management System: A DRMS provides an integrated management application for managing Demand Response programs and implementing demand response events on the distribution grid. Demand response (DR) balances customers' need for electricity with the utilities' responsibility to successfully operate the system. A well-conceived and well-managed portfolio of demand response programs provides cost-effective and useful ancillary services and capacity for grid operations. DR programs may be implemented by the utilities and/or through 3rd-party administrators.

Facilities

Ongoing utility operations require efficient and effective business facilities infrastructure to meet customer and workforce needs. The foundational capital investments required to support these needs include routine investments for building facilities sustenance and vehicle replacements.

FOUNDATIONAL CAPITAL INVESTMENT PROJECT DESCRIPTIONS

This section describes the capital investment projects.

Reliability

H0002612: 6800 Line Recond Ph 2

Replace approximately 6 miles of existing 2/0, 69kV conductors with higher capacity conductors, from P-165 south thru Puu Huluhulu and Puu Waa Waa substations to P-225.

H0002668: 6800 Line Recond Ph 3

Replace approximately 6.9 miles of existing 2/0, 69kV conductors from P-225 south to P-290.

H0002669: 6800 Line Recond Ph 4

Replace approximately 1.5 miles of existing 2/0, 69kV conductors with higher capacity conductors, from P-290 south to P-306X Kaalele Street Intersection.

Keamuku 6200 Reloc Ph 4, 5 and 6

Phases 4, 5 and 6 of approximately 6 phases (one per year) ending in 2022 to increase reliability and accessibility. Relocation of 6200 line from the forest reserve/conservation zone areas to highway right-of-way.

CT 4 - 50,000 Rebuild

50,000 hour combustion turbine overhaul.

CT 5 - 50,000 Rebuild

50,000 hour combustion turbine overhaul.

H0002724: CT5 Zero Time

50,000 hour combustion turbine overhaul.

H0002779: Keamuku 6200 Reloc Ph 1

Phase 1 of approximately 6 phases (one per year) ending in 2022 to increase reliability and accessibility. Relocation of 6200 line from the forest reserve/conservation zone areas to highway right-of-way.

H0002913: Keamuku 6200 Reloc Ph3

Phase 3 of approximately 6 phases (one per year) ending in 2022 to increase reliability and accessibility. Relocation of 6200 line from the forest reserve/conservation zone areas to highway right of way.

H0002914: Keamuku 6200 Reloc Ph2

Phase 2 of approximately 6 phases (one per year) ending in 2022 to increase reliability and accessibility. Relocation of 6200 line from the forest reserve/conservation zone areas to highway right of way.

H0002929: 3300 Line Rebuild Ph 3

Repair, replace and reconductor 20 miles of 34.5kV line which runs from Waimea, over Kohala Mountain and services the North Kohala district.

H0002930: 3300 Line Rebuild Phase 2

Repair, replace and reconductor 20 miles of 34.5kV line which runs from Waimea, over Kohala Mountain and services the North Kohala district.

H0002931: 3300 Line Rebuild - Ph 1

Repair, replace and reconductor 20 miles of 34.5kV line which runs from Waimea, over Kohala Mountain and services the North Kohala district.

TRANSFORMATIONAL CAPITAL INVESTMENT PROJECT DESCRIPTIONS

DG Enabling Investments

DGIP

Circuit upgrades and other mitigation measures to increase the capacity of the electrical grids and enable the interconnection of additional DG.

Liquefied Natural Gas

H0002986: Keahole LNG Conversion

Project to convert the Keahole combustion turbine units to enable operation with LNG and maintain dual fuel capability.

H0002987: CT 3 LNG Conversion

Project to convert CT3 combustion turbine unit to enable operation with LNG and maintain dual fuel capability.

HEP LNG Conversion

Project to convert the HEP plant combustion turbine units to enable operation with LNG and maintain dual fuel capability. The plant is an IPP which we will supply the LNG per the contract and we will be responsible for the equipment conversion cost. A negotiation with the IPP will also be required to accomplish this upgrade

Facilitates New or Renewable Energy Total

Transm. Capital (West Geo)

When the proposed geothermal generating plant is installed in West Hawai'i a transmission line interconnection and substation will be installed. The interconnection in the west Hawai'i region is much less than one for a generating unit in the east Hawai'i regions.

Transm. Capital (Wind)

When the proposed Wind generating plant is installed on Hawai'i Island transmission line interconnection and substation will be installed

Replacement DG Levelized Capacity Costs

Hill 5 - Deactivation

The cost for deactivation will be to lay up the plant in a manner that is will be preserved and capable of returning to service with a minimal amount of effort and time when and if the system needs require return to service. The decommissioning costs are to make the unit safe. This will require the removal of all hazardous materials and prepare the unit for the final disposition

Hill 6 - Deactivation

The cost for deactivation will be to lay up the plant in a manner that is will be preserved and capable of returning to service with a minimal amount of effort and time when and if the system needs require return to service. The decommissioning costs are to make the unit safe. This will require the removal of all hazardous materials and prepare the unit for the final disposition

Puna - Deactivation

The cost for deactivation will be to lay up the plant in a manner that is will be preserved and capable of returning to service with a minimal amount of effort and time when and if the system needs require return to service. The decommissioning costs are to make the unit safe. This will require the removal of all hazardous materials and prepare the unit for the final disposition

Smart Grid and Demand Response

H0001917: Smart Grid

The Smart Grid Full Implementation Project will 1) install devices in the field, such as meters, remote controllable switches, fault circuit indicators, capacitors, and load controlling switches, 2) install central office software designed to collect information from the field devices and/or then execute commands or tasks by a system operator for the purposes of managing the grid or managing the utilities' meter reading and field services business processes and 3) provide the Hawaiian Electric Companies' customers with tools which enables them to understand and manage their energy use and energy bill. The benefits for implementing the Smart Grid Full Implementation Project is to 1) lower electricity bills through savings and productivity improvements in utility operations, 2) increase renewable energy through integrated distributed generation, 3) provides tools to the customers to enable them to utilize their energy more effectively/efficiently, and 4) increase reliability through outage notification and distribution automation which can lower SAIFI and CAIDI.

System Security Investments

20 MW Contingency BESS (2017)

The 20 MW battery addition is to provide the system security needs as we begin operating with less steam units in service that provide grid frequency and voltage control during system upsets and loss of generating units. This solution is more cost effective then operating and additional generating unit.

5 MW Regulation BESS (2017)

The 5 MW battery addition is to provide the system security needs as we begin operating with less steam units in service that provide grid frequency and voltage control during system upsets and loss of generating units. This solution is more cost effective then operating and additional generating unit.

Breaker Clearing Time Improvement

The growth of PV has reached the level that has put the electrical system at risk of failure due to a significant fault. This project is for reduction of the clearing time on circuit Breaker to clear the faults faster and preventing a potential collapse of the grid.

CAPITAL EXPENDITURES BY CATEGORY AND PROJECT

Capital Expenditures: 2015–2019

Table K-2 lists the budgeted, annualized dollar amount for each project; with totals by project group and by category, for the years 2015–2019. Table K-3 lists the budgeted, annualized dollar amount for each project; with totals by project group and by category, for the years 2020–2030 with project totals.

Project	2015	2016	2017	2018	2019
Foundational	**61,467,515**	**61,817,185**	**57,486,588**	**63,261,350**	**63,285,593**
Asset Management	1,579,506	813,996	1,115,984	1,152,459	1,157,741
Baseline	1,579,506	813,996	1,115,984	1,152,459	1,157,741
Customer Connections	3,531,590	4,677,292	6,469,981	6,554,503	5,224,555
Baseline	3,531,590	4,677,292	6,469,981	6,554,503	5,224,555
Customer Projects	558,481	5,371,298	-641,680	-623,625	940,565
Baseline	558,481	5,371,298	-641,680	-623,625	940,565
Enterprise IT Network	39,471	80,522	70,261	80,522	40,261
Baseline	39,471	80,522	70,261	80,522	40,261
Facilities	7,854,221	7,512,313	5,237,690	4,155,895	4,863,875
Baseline	7,854,221	7,512,313	5,237,690	4,155,895	4,863,875
Reliability	36,139,572	31,443,943	30,556,255	36,460,215	35,406,072
6200 Line Project (Ph 4, 5 and 6)	0	0	0	0	0
CT 4 - 50,000 Rebuild	0	0	0	0	0
CT 5 - 50,000 Rebuild	0	0	0	0	0
H0002612: 6800 Line Recond Ph 2	7,952,742	0	0	0	0
H0002668: 6800 Line Recond Ph 3	597,934	6,980,000	0	0	0
H0002669: 6800 Line Recond Ph 4	626,090	3,353,000	0	0	0
H0002724: CT5 Zero Time	634,764	3,148,394	0	0	0
H0002779: Keamuku 6200 Reloc Ph 1	0	558,848	10,444,335	0	0
H0002913: Keamuku 6200 Reloc Ph3	0	0	0	608,214	11,606,064
H0002914: Keamuku 6200 Reloc Ph2	0	0	595,215	11,604,995	0
H0002929: 3300 Line Rebuild Ph 3	0	0	0	0	5,845,000
H0002930: 3300 Line Rebuild Phase 2	0	0	0	6,499,640	0
H0002931: 3300 Line Rebuild - Ph 1	0	0	5,136,636	0	0
T0001825: Keamuku 6200 Reloc Ph 4	0	0	0	0	608,214
Baseline	26,328,042	17,403,701	14,380,069	17,747,366	17,346,794

Project	2015	2016	2017	2018	2019
Safety, Security and Environmental	11,764,674	11,917,821	14,678,097	15,481,381	15,652,524
Baseline	11,764,674	11,917,821	14,678,097	15,481,381	15,652,524
Transformational	**22,811,602**	**60,934,136**	**38,705,798**	**11,357,317**	**14,618,804**
DG Enabling Investments	2,045,064	2,045,064	338,084	338,084	338,084
DGIP	2,045,064	2,045,064	338,084	338,084	338,084
Liquefied Natural Gas	3,007,097	14,135,222	12,897,848	0	0
H0002986: Keahole LNG Conversion	1,354,117	6,239,083	4,734,926	0	0
H0002987: CT 3 LNG Conversion	192,980	1,896,139	3,432,921	0	0
HEP LNG Conversion	1,460,000	6,000,000	4,730,000	0	0
LNG Conversion	0	0	0	0	0
Facilitates New or Renewable Energy	4,138,473	0	684,483	3,422,415	9,582,763
Transm. Capital (West Geo)	0	0	0	0	0
Transm. Capital (Wind)	0	0	684,483	3,422,415	9,582,763
Baseline	4,138,473				
Replacement DG Levelized Capacity Costs	0	0	0	0	0
Hill 5 - Deactivation	0	0	0	0	0
Hill 6 - Deactivation	0	0	0	0	0
Puna - Deactivation	0	0	0	0	0
Smart Grid and Demand Response	0	16,495,177	13,423,656	1,917,222	1,835,211
H0001917: Smart Grid	0	16,495,177	13,423,656	1,917,222	1,835,211
System Security Investments	13,620,968	28,258,673	11,361,728	5,679,596	2,862,746
20 MW Contingency BESS (2017)	2,555,086	14,478,823	0	0	0
5 MW Regulation BESS (2017)	862,522	4,887,625	0	0	0
Baseline	6,903,360	5,592,225	8,061,728	5,679,596	2,862,746
Breaker Clearing Time Improvement	3,300,000	3,300,000	3,300,000	0	0
Grand Totals	**84,279,117**	**122,751,321**	**96,192,386**	**74,618,667**	**77,904,397**

Table K-2. Capital Expenditures by Category and Project: 2015–2019

Capital Expenditures: 2020–2030 with Project Totals

Table K-3 lists the budgeted, annualized dollar amount for each project; with totals by project group and by category, for the years 2020–2030 with project totals.

Project	2020	2021–2025	2026–2030	Totals
Foundational	**57,857,221**	**271,338,062**	**277,287,042**	**913,800,553**
Asset Management	1,176,265	6,169,723	6,679,350	19,845,023
Baseline	1,176,265	6,169,723	6,679,350	19,845,023
Customer Connections	5,308,148	27,842,202	30,142,004	89,750,276
Baseline	5,308,148	27,842,202	30,142,004	89,750,276
Customer Projects	955,614	5,012,371	5,426,399	16,999,423
Baseline	955,614	5,012,371	5,426,399	16,999,423
Enterprise IT Network	30,745	291,279	354,625	987,686
Baseline	30,745	291,279	354,625	987,686
Facilities	4,941,697	25,920,097	28,061,130	88,546,917
Baseline	4,941,697	25,920,097	28,061,130	88,546,917
Reliability	28,814,342	118,872,881	112,188,782	429,882,060
6200 Line Project (Ph 4, 5 and 6)	10,000,000	20,000,000	0	30,000,000
CT 4 - 50,000 Rebuild	0	3,900,000	0	3,900,000
CT 5 - 50,000 Rebuild	0	0	4,140,000	4,140,000
H0002612: 6800 Line Recond Ph 2	0	0	0	7,952,742
H0002668: 6800 Line Recond Ph 3	0	0	0	7,577,934
H0002669: 6800 Line Recond Ph 4	0	0	0	3,979,090
H0002724: CT5 Zero Time	0	0	0	3,783,157
H0002779: Keamuku 6200 Reloc Ph 1	0	0	0	11,003,183
H0002913: Keamuku 6200 Reloc Ph3	0	0	0	12,214,277
H0002914: Keamuku 6200 Reloc Ph2	0	0	0	12,200,210
H0002929: 3300 Line Rebuild Ph 3	0	0	0	5,845,000
H0002930: 3300 Line Rebuild Phase 2	0	0	0	6,499,640
H0002931: 3300 Line Rebuild - Ph 1	0	0	0	5,136,636
T0001825: Keamuku 6200 Reloc Ph 4	0	0	0	608,214
Baseline	18,814,342	94,972,881	108,048,782	315,041,977
Safety, Security and Environmental	16,630,410	87,229,509	94,434,752	267,789,168
Baseline	16,630,410	87,229,509	94,434,752	267,789,168

Project	2020	2021–2025	2026–2030	Totals
Transformational	**4,947,607**	**39,259,556**	**20,565,669**	**213,200,492**
DG Enabling Investments	338,084	131,990	131,990	5,706,444
DGIP	338,084	131,990	131,990	5,706,444
Liquefied Natural Gas	0	0	0	30,040,167
H0002986: Keahole LNG Conversion	0	0	0	12,328,127
H0002987: CT 3 LNG Conversion	0	0	0	5,522,040
HEP LNG Conversion	0	0	0	12,190,000
LNG Conversion	0	0	0	0
Facilitates New or Renewable Energy	0	14,992,548	0	32,820,683
Transm. Capital (West Geo)	0	14,992,548	0	14,992,548
Transm. Capital (Wind)	0	0	0	13,689,662
Baseline	0	0	0	4,138,473
Replacement DG Levelized Capacity Costs	0	0	0	0
Hill 5 - Deactivation	0	0	0	0
Hill 6 - Deactivation	0	0	0	0
Puna - Deactivation	0	0	0	0
Smart Grid and Demand Response	1,700,973	8,879,143	3,917,649	48,169,031
H0001917: Smart Grid	1,700,973	8,879,143	3,917,649	48,169,031
System Security Investments	2,908,550	15,255,875	16,516,030	96,464,167
20 MW Contingency BESS (2017)	0	0	0	17,033,909
5 MW Regulation BESS (2017)	0	0	0	5,750,147
Baseline	2,908,550	15,255,875	16,516,030	63,780,111
Breaker Clearing Time Improvement	0	0	0	9,900,000
Grand Totals	**62,804,828**	**310,597,618**	**297,852,711**	**1,127,001,045**

Table K-3. Capital Expenditures: 2020–2030 with Project Totals

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L. Preferred Plan Development

Hawai'i Island is at the forefront of defining and designing the electric system of the future. Our task is especially challenging. We are blessed with immense renewable resources, and yet, the relatively small size of the autonomous island grid system makes integration of certain technologies especially challenging. Nevertheless, we are transforming our power supply portfolio to produce unprecedented levels of renewable energy, while continuing to provide reliable and safe electric service to all customers at a reasonable cost.

The Preferred Plan was developed within a highly analytical, and innovative process. These elements were critical in developing the Preferred Plan. Collaboration between power system planners, consultants, domain experts, and Hawai'i Electric Light leadership was critical in maintaining focus, gaining insights, and meeting the challenge of encouraging independent thinking while maintaining common purpose. Best-of-class analytics were used to construct and evaluate complex plans within a number of contexts: feasibility, costs, risks, flexibility, and sustainability. And with analytics at the center of the effort, in innovative ways we identified ways to leverage energy storage and renewable variable energy sources.

The planning process leveraged the insights gained from analysis performed earlier, both internally and by consultants, described in the Power Supply Plan.[1] It provided the basis for sensitivity analyses, performed in parallel by two modeling teams. Utilizing the expertise of different modeling teams helped gain confidence in the final recommendation by seeing if different models and approaches provided similar, reinforcing results.

[1] Hawai'i Electric Light filed the Power Supply Plan with the Commission on April 21, 2014, Docket No. 2012-0212.

The two teams worked together to move from concept, through refinement, to definition of the Preferred Plan as shown in Figure L-1.

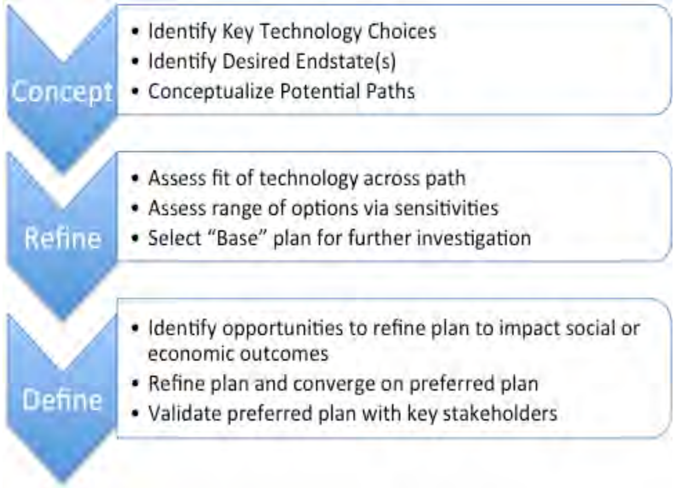

Figure L-1. Process for Developing the Preferred Plan

The analysis focused on transforming today's system into an electrical system that safely and securely integrates various sources of renewable energy by 2030. The analysis was carried out in three major steps:

1. **Develop a Base Plan:** A Base Plan was constructed which was similar to the base plan for the PSP. With an extended time frame, however, changes to fuel and demand forecasts, inclusion of demand response impacts, and various assumptions related to DG-PV.

2. **Perform Sensitivity Analyses:** Sensitivity analyses were then performed to the Base Plan to test candidate changes.

3. **Use Sensitivity Results to Develop the Preferred Plan:** The results of the sensitivity analyses were reviewed and used to develop the Preferred Plan.

Actions taken now and projects developed in the next five years will have an impact on what is possible in the future. Therefore, great care was taken to define a Preferred Plan that is flexible enough to accommodate emerging resource options that become commercially ready in the future. The Preferred Plan positions Hawai'i Electric Light to address both current and emerging technology options.

METHODOLOGY FOR DEVELOPING THE PREFERRED PLAN

The PSIP planning team constructed and evaluated a number of strategy canvases to feed a more granular and complex process that vetted technology options. Development of the Preferred Plan was driven by the following concepts:

- Focus on affordable and stable energy costs while preserving system reliability. Where applicable or where the analysis was indifferent, renewable energy is preferred. The analysis considered feasible options given specifics of each island while evaluating the economic impacts. The economic impact is of significant consideration for Hawaiʻi Island, given that it already incorporates a very high amount of renewable energy so new additions are prioritized by their ability to provide more affordable and stable energy costs.
- Develop a grid with the appropriate mix of resources and operational tools necessary to provide reliable service to our customers.
- Utilize conventional, dispatchable thermal assets and dispatchable renewable energy assets to provide firm generation, regulation and other grid services.
- Utilize LNG to improve fuel supply economics and reduce CO_2 emissions from fossil units where this is a cost-effective strategy.
- Maintain reliability and security by assuring grid operational needs are met and can keep pace with changing mix of generation sources, including leveraging cost-effective energy storage and demand response.

The modeling teams focused on constructing tactical plans to identify specific steps required to transition from current state to future state. This was a complex and iterative process. Plans were broken down into a series of annual capital project/retirement plans; each plan was verified against system security requirements. Operations of the system within each annual plan was carried out by using detailed production simulation models that commit and dispatch assets, manage regulation, utilize energy storage systems (ESS), demand response, and other assets to address variability of solar or wind generation potential. As discussed further in Appendix C, these models apply detailed hourly and sub-hourly dispatch models to evaluate resource options.

The planning process leveraged two different models to address simulation requirements. Collectively, the teams worked together to move the plan from concept, through refinement, to definition of the preferred plan. Specific milestones within the planning process included:

- Identification of key success factors or critical technology investments underpinning the 2030 strategy (that is, diversification of renewables to mitigate negatives of solar energy profiles, early adoption of advanced battery for contingency and regulation reserves, LNG supply for thermal assets). The models also incorporated demand response based on the identified potential quantities and uses.

- Validation of the supply mix and roles between variable renewables, dispatchable renewables, storage, and thermal assets to address system reliability requirements; this mix defines the degree to which variable assets can be cost-effectively leveraged.
- Optimization of the resource portfolio based on requirements during each of year of the study period; identify blend of possible dispatchable and variable generation opportunities.
- Based on economic dispatch requirements and demand requirements (with consideration of capacity value of variable resources and possible impacts of demand response), re-evaluate retirement schedules identified in PSP and identify intrinsic value of shifting retirement dates.
- Identify and test alternate technology mixes, timing, and other pro and cons via sensitivity analysis.
- Expand sensitivity analysis into areas of key interest: the key area of interest was the best way to address security requirements from increasing distributed solar PV, followed by the economic viability of further expanding wind and/or geothermal resources.
- Define the Preferred Plan based sensitivities; verification of plan outcomes by all models and modeling teams.

System reliability requirements for regulating and contingency reserves were met through a variety of resources including demand response, energy storage, and thermal generation. As increasing amounts of renewable variable generation were added to the system, the system reliability requirements change to reflect the new generation mix. The analysis incorporated system security analysis for scenarios presented, in part, in Chapter 4.

Sub-hourly models were deployed during the course of the analysis. Results were compared to hourly models to identify whether substantial changes to the modeling results occurred; sub-hourly models confirmed the need for increased need for system balancing cause by variable resources; increasing the regulating reserve and ramping requirements.

BASE PLAN

The present operation incorporates various generating unit options including daily and seasonal cycling of thermal generation, and planned deactivation and decommission dates for Puna and Hill steam units. The fuel costs, demand forecasts, demand response quantities and uses, and DG-PV growth were set inputs to the analysis.

The demand forecast included consideration of the impact of dynamic pricing in the demand shape as defined in the IDRPP.[2] The impact of demand response on the peak and its possible use for regulating reserve based on IDRPP maximum potential were also inputs to the analysis. These changes were incorporated into the simulation models.

The base plan also includes the following assumptions regarding which units would be converted to LNG fuel, and the start date for the new biomass resource.

- **Utility Generation:** Puna CT3 and Keahole CT4 and CT5 will fuel switch to LNG in 2017.
- **Hamakua Energy Partners (HEP):** Will fuel switch to LNG in 2018.
- **Hu Honua:** Hu Honua is anticipated to be in service from 2015.

Based on an assessment of use under unconstrained economic dispatch, as well as the revised peak forecasts which reflect the impact of dynamic pricing, the Base Plan retained the deactivation and decommission schedules for Puna and Hill, and identified new dates for Hill 6. The first steam unit (Puna) deactivation occurs in 2018. This year was chosen based on the anticipated addition of the Hu Honua facility, with provision to retain capacity during a proving period of the new biomass facility. Units are retired (decommissioned) two years after deactivation. We plan to deactivate the following existing generation:

- Puna steam in 2018
- Hill 5 in 2020
- Hill 6 in 2022

System reliability requirements for regulating and contingency reserves are met through a variety of resources including demand response, energy storage, and dispatchable generation (renewable and fossil resources). As increasing amounts of variable generation are added to the system (through growth in DG-PV, and other projects), the system security requirements change to reflect the new generation mix.

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[2] The Companies field its *Integrated Demand Response Portfolio Plan (IDRPP)* with the Commission on July 28, 2014.

SENSITIVITY ANALYSES

Sensitivity analyses were performed on the Base Plan to demonstrate the effect of various changes to the system. The sensitivity analyses evaluated the following:

1. Cost effectiveness of meeting contingency reserves and regulation/ramping due to DG-PV with increased storage or additional online reserves
2. Additional wind in West Hawaiʻi in 2020
   - No limit on curtailment
   - If curtailment of individual projects is excessive, then consider additional analysis
   - Use utility-scale wind operated at reduced dispatch levels (curtailed) to provide ancillary services
3. Dispatchable 25 MW geothermal resource in West Hawaiʻi in 2025
4. Dispatchable 25 MW geothermal resource in East Hawaiʻi in 2020
5. Dispatchable 25 MW geothermal resources in both West and East (2025 and 2020) (total of 50 MW)
6. Pumped Storage Hydro
7. Dispatchable waste-to-energy resource in 2020

Sensitivity analyses were performed to test how resource(s) would affect the Base Plan and whether it should be considered for incorporation into the Preferred Plan.

Additional Wind

The analysis was for a wind facility located in West Hawaiʻi, in a location where there are excellent wind resources and that would not require significant transmission infrastructure to support. The potential energy profile was derived from actual performance of the wind facility at the south part of Hawaiʻi Island.

This sensitivity analysis began with an added 40 MW of wind. An additional 40 MW of wind decreased the overall system costs compared to the Base Plan, but with substantial curtailment of the new facility.

A second sensitivity with 20 MW of wind was analyzed and found to also decrease the overall system cost with less curtailment and a lower initial investment (due to the smaller size). This 20 MW resource was chosen for the Preferred Plan.

Additional Wind Providing Ancillary Services

This sensitivity added 40 MW of wind with the ability to provide ancillary services (regulation and ramping reserves) to the system. The results of this analysis were mixed, with one team showing somewhat increased costs, and the other model showing decreased costs.

Additional 25 MW Geothermal in West Hawaiʻi

This sensitivity analysis added 25 MW of new geothermal on the west side of Hawaiʻi Island in 2025. The geothermal was assumed to be dispatchable with 7 MW minimum dispatch load, with the operational and technical characteristics to meet the system security requirements provided by the present Keahole plant and operate in its place. This sensitivity decreased the overall system costs compared to the Base Plan.

Additional 25 MW Geothermal in East Hawaiʻi

This sensitivity analysis added 25 MW of new geothermal on the east side of Hawaiʻi Island in 2020. This facility was assumed to have the operational characteristics to support system security, and dispatch range similar to the West Hawaiʻi case. However, due to the location more transmission infrastructure is required and the facility could not operate to meet security constraints that require generation in West Hawaiʻi. This sensitivity increased the overall system costs compared to the Base Plan in one model. Although the costs decreased in the other model, it was not as beneficial as the West Hawaiʻi sensitivity.

Waste-To-Energy

This sensitivity added an 8 MW of waste-to-energy resource in 2020. This sensitivity found the addition of this resource increased the overall system costs compared to the Base Plan by one model, and slightly reduced costs in the other model; in the model where it reduced costs compared to the base plan it was not as cost-effective as wind or West Hawaiʻi Geothermal.

Additional 25 MW Geothermal in East Hawaiʻi and 25 MW Geothermal in West Hawaiʻi

This sensitivity analysis added 25 MW of new geothermal on the east side of Hawaiʻi Island in 2020 and in West Hawaiʻi in 2025, incorporating the assumptions of the East and West Hawaiʻi individual scenarios. This sensitivity was not selected as the preferred plan as the findings were not as beneficial as the wind and West Hawaiʻi Geothermal scenarios.

Additional Wind and Geothermal

This sensitivity added 20 MW of wind in 2020, and 25 MW of geothermal in West Hawaiʻi in 2025. This sensitivity reduced the overall system costs compared to the Base Plan, although the results of the models did not concur as to whether this was superior to West Hawaiʻi Geothermal as a single addition. Since this plan supported resource diversity, with benefits being provided by the earlier installation of 2020 (as compared to West Hawaiʻi Geothermal in 2025 alone), and as both models identified this as a plan offering reduced costs over the base plan, this was selected as the Preferred Plan.

Energy Storage

Pumped storage hydro (PSH) and load shifting battery energy storage have similar operating characteristics. Both can reduce curtailment by accepting curtailed renewable energy during the day to be discharged at the evening peak.

25 MW Pumped Storage Hydro

This sensitivity analysis added a 25 MW pumped storage hydro in 2020 into the Preferred Plan. The 25 MW pumped storage hydro addition increased the overall system costs compared to the Preferred Plan.

5 MW Battery Energy Storage

This sensitivity analysis added a 5 MW flow battery with characteristics to provide load shifting in 2020. The 5 MW flow battery addition increased the overall system costs compared to the Base Plan .

PREFERRED PLAN

The results of the sensitivity analyses were used to select the Preferred Plan to achieve cost savings to our customers as compared to the base plan, and increase resource diversity and price stability by increasing the amount of renewable energy on the system. The Preferred Plan incorporated demand response programs: demand behavior modification, customer controlled capacity, ramping capabilities, offline reserve, and time of use load shifting. The Preferred Plan incorporates storage for the changing system security and reliability needs from the increasing DG-PV. A 15 MW ESS will be added for system security and reliability, providing fast-responding contingency reserves. A 5 MW storage will provide fast-ramping regulation. New wind and geothermal are added, which, along with the existing and planned renewable resources and DG-PV growth on the system push our RPS estimate to over 90% in 2030.

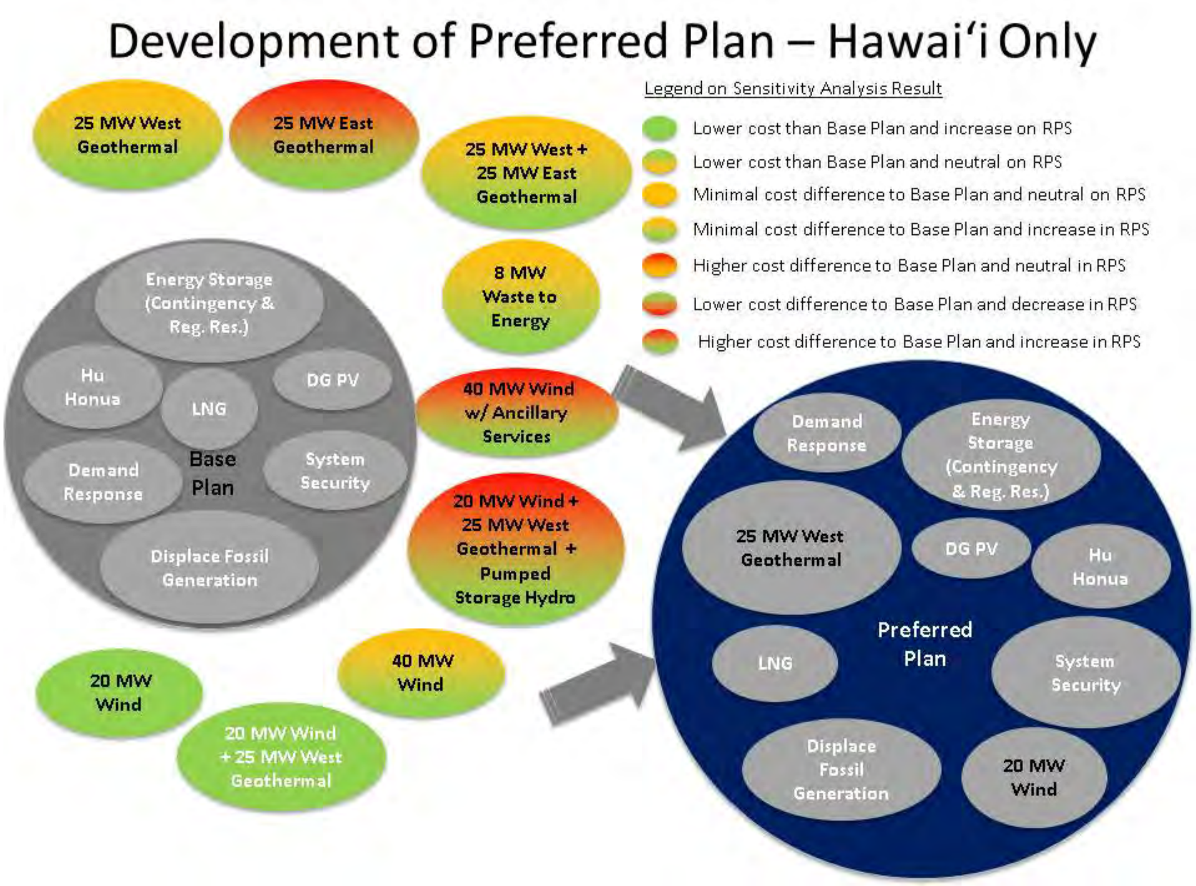

Figure L-2. Process for Developing the Preferred Plan

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M: Planning Standards

This appendix contains the details of the planning standards TPL-001 and BAL-052.

TPL-001-0: TRANSMISSION PLANNING PERFORMANCE REQUIREMENTS

The starting document for HI-TPL-001-0 was NERC standard TPL-001-2 dated August 4, 2011. The standard includes the merging of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single comprehensive, coordinated standard and retirement of TPL-005-0 and TPL-006-0.

The only added complexity was that the differently sized power systems in Hawaiʻi would need different levels of system reliability. The Hawaiʻi standard has three groups to address the different sizes of the various Balancing Areas.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Working Group Glossary of Terms, Version 1 – 20120304 are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Balancing Authority (BA): The responsible entity that integrates resource plans ahead of time, maintains load-generation balance within a Balancing Authority Area, and governs the real time operation and control of the Balancing Area. (Source: Modified from Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Balancing Authority Area: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012)

Base Year: The 2011 BA's transmission and generation system shall be used as the base year to establish performance standards utilized with this standard. (Source: Proposed RSWG proposed definition.)

Cascading: The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Corrective Action Plan: A list of actions and an associated timetable for implementation to remedy a specific problem. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Equipment Rating: The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Facility: A set of electrical equipment that operates as a single Bulk Electric System Element (for example, a line, a generator, a shunt compensator, transformer, etc.). (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Near-Term Transmission Planning Horizon: The transmission planning period that covers Year One through five. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive load, or (3) load that is disconnected from the system by end-user equipment. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Off-Peak: Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Operating Procedure: A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Protection System: Protection system are:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

(Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Protection Reserves: The resources under the control of the Under Frequency Load Shedding System designed to protect the system against single or multiple contingency events. (Source: RSWG proposed definition.)

Special Protection System (SPS) or Remedial Action Scheme: An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and MVAr), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Stability: The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

System: A combination of generation, transmission, and distribution components. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Transmission: An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers. (Source: Modified Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Year One: Year One is the first year of planning studies for future planning and evaluation requirements. (Source: Modified Glossary of Terms Used in NERC Reliability Standards February 8, 2012, Reliability First Regional Definitions.)

Introduction

Purpose: Establish Transmission system planning performance requirements within the planning horizon to develop a system that will operate reliably over a broad spectrum of conditions and following a wide range of probable Contingencies.

Applicability: Balancing Authorities (BA)

Facilities: The Facilities are divided into three groups A, B, and C. All groups are divided based on the annual system peak demand.

- Group A: Annual system peak is greater than or equal to 500 MW.
- Group B: Annual system peak is greater than or equal to 50 MW and less than 500 MW.
- Group C: Annual system peak is less than 50 MW.

Effective Date: To be determined

B. Requirements

R1. The BA must maintain system models for performing the studies needed to complete its Planning Assessment. The models must use data consistent with that provided in accordance with the HI-MOD-010 Development and Reporting of Steady State System Models and Simulations and HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and must represent projected system conditions. This establishes Category P0 as the normal system condition in Table 1.

R1.1. System models must represent:

R1.1.1. Actual steady-state characteristics of system resources and loads as defined in HI-MOD-010 Development and Reporting of Steady State System Models and Simulations.

R1.1.2. Actual dynamic characteristics of system resources and loads as defined in HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations.

R1.1.3. Planned Facilities and changes to existing Facilities

R1.2. The Generation resources must maintain or better the following characteristics unless the change can be verified by study that the results will provide acceptable reliability. The characteristics of the system that meet the acceptable reliability criteria will be used as the new benchmark for future planning until the reliability criteria is changed.

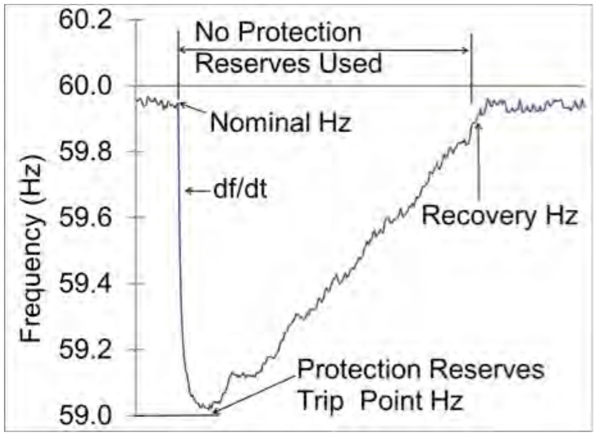
R1.2.1. Each Balance Authority system will be planned to meet the requirements Disturbance Recovery performance in HI-BAL-002 Disturbance Control Performance.

R1.2.2. The loss of the largest single contingency may result in a loss of load within the acceptable reliability criteria defined in BAL-002 Disturbance Control Performance.

R1.2.3. Each resource will have frequency ride-through designed such that all generation, reserves, regulation and voltage control resources will withstand single and excess contingency events defined in HI-BAL-002 Disturbance Control Performance. The ride-through capability will meet the criteria designed to be protected under HI-PRC-006 Underfrequency Load Shedding, without the loss of, or damage to any resource.

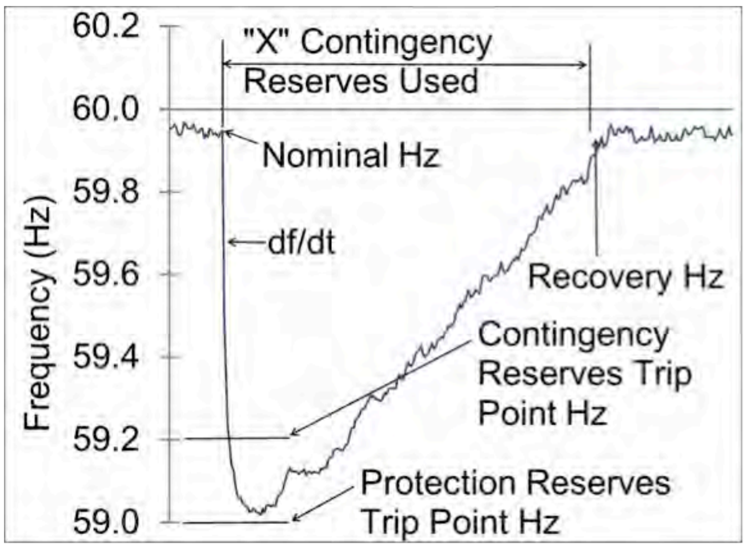
R1.2.4. The system will be planned such that the resultant impacts of inertia, unit response or reserve response will meet the system frequency response characteristics following the loss of the largest single contingency as defined below.

Frequency Response: For all BA systems the loss of the largest unit(s) or any single contingency should not result in activation of the protection reserves. In addition, the rate of change of frequency df/dt is not to increase over historical levels, without prior review of impacts on system protection operation and critical resources. A sample system performance characteristic is shown in the graph below:



System Using No Protection Reserves

An example characteristic graph of a system that utilizing the protection reserves is indicated below:



System Using Protection Reserves

R.1.2.5. The system will be planned such that all generation, reserves, regulation and voltage control resources will withstand the most severe voltage ride-thru requirement for a single contingency event, including both transmission and distribution events and distribution and transmission fault reclose cycles, through the duration of their reclosing cycle, without the loss of or damage to any resource.

R1.2.6. The system will be designed such that all generation, reserves, regulation and voltage control resources will withstand excess contingency events defined in HI-BAL-002 Disturbance Control Performance for voltage ride-thru requirement for an excess contingency event and designed to be protected under HI-PRC-006

Underfrequency Load Shedding, without the loss of or damage to any resource.

R1.2.7. The system will be planned to be transiently and dynamically stable following any single contingency event or any excess contingency event designed to be protected under HI-PRC-006 Underfrequency Load Shedding. Stability will be defined that the system will survive the first swing stability and the second swing and each subsequent swing will be lesser in magnitude than its predecessor (damped response). All swings will be effectively eliminated within 20 seconds of the initiating event.

R1.2.8. The system shall be designed to supply the required ancillary services necessary to provide voltage and frequency response to meet the reliability requirements of each BA's service tariff and R1.2.2.

R2. The BA must prepare an annual Planning Assessment of its system. This Planning Assessment must use current or qualified past studies (as indicated in R2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses.

R2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis must be assessed annually and be supported by current annual studies or qualified past studies as indicated in R2.6. Qualifying studies need to include the following conditions:

R2.1.1. System peak load for either year one or year two, and for year five.

R2.1.2. System minimum with maximum and minimum variable renewables (night-time load) load for one of the five years.

R2.1.3. System minimum day load, maximum variable renewable for one of the five years.

R2.1.4. System day-peak load with maximum variable renewable and minimum variable renewable for one of the five years.

R2.1.5. System peak load, no variable renewable for one of the five years.

R2.1.6. For each of the studies described in R2.1.1 through R2.1.5, sensitivity case(s) must be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in system response:

- Real and reactive forecasted load.
- Expected transfers.
- Expected in-service dates of new or modified Transmission Facilities.
- Planned or unplanned outages of critical resources for ancillary services
- Typical generation scenarios including outage of the typically operated generation sources
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable loads and Demand Side Management.

R2.1.7. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on system performance must be studied. The studies must be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

R2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis must be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in R2.6:

R2.2.1. A current study assessing expected system peak load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

R2.3. The short circuit analysis portion of the Planning Assessment must be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in R2.6. The analysis must be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the system short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

R2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis must be assessed annually and be supported by current or past studies as qualified in R2.6. The following studies are required:

R2.4.1. System peak load for one of the five years. System peak load levels must include a load model which represents the expected dynamic behavior of loads that could impact the study area, considering the behavior of induction motor loads or other load characteristics, including the model of distributed generation, Demand Response and other programs that impact system load characteristics. An aggregate system load model which represents the overall dynamic behavior of the load is acceptable.

R2.4.2. System minimum load for one of the five years.

R2.4.3. System minimum with maximum and minimum variable renewables (night-time load) load for one of the five years.

R2.4.4. System minimum day load, maximum variable renewable for one of the five years.

R2.4.5. System day-peak load, maximum and minimum variable renewable for one of the five years.

R2.4.6. System peak load, no variable renewable for one of the five years.

R2.4.7. For each of the studies described in R2.4.1 through R2.4.6, sensitivity case(s) must be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, load forecast, or dynamic load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability
- Maintenance periods of generation resources and alternative resources providing ancillary services.
- Generation additions, retirements, or other dispatch scenarios.

R2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis must be assessed to address the impact of proposed material generation additions or changes in that time frame and be supported by current or past studies as qualified in R2.6 and must include documentation to support the technical rationale for determining material changes.

R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

R2.6.1. For steady state, short circuit, or Stability analysis: the study must be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

R2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the system represented in the study. Documentation to support the technical rationale for determining material changes must be included.

R2.7. For planning events shown in Table 1, when the analysis indicates an inability of the system to meet the performance requirements in Table 1, the Planning Assessment must include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned system must continue to meet the performance requirements in Table 1. The Corrective Action Plan(s) must:

R2.7.1. List system deficiencies and the associated actions needed to achieve required system performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations
- Installation or modification of manual and automatic generation runback or tripping as a response to a single or multiple Contingency to mitigate steady state performance violations

- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan
- Use of rate applications, DSM, alternative resources and technologies, or other initiatives

R2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

R2.7.3. If situations arise that are beyond the control of the BA that prevent the implementation of a Corrective Action Plan in the required time frame, then the BA is permitted to utilize Non-Consequential Load Loss to correct the situation that would normally not be permitted in Table 1, provided that the BA documents that they are taking actions to resolve the situation. The BA must document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load.

R2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified system Facilities and Operating Procedures.

R2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in R2.3 exceeds their Equipment Rating, the Planning Assessment must include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan must:

R2.8.1. List system deficiencies and the associated actions needed to achieve required system performance.

R2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, the BA must perform studies for the Near-Term and Long-Term Transmission Planning Horizons in R2.1, and R2.2. The studies must be based on computer simulation models using data provided in R1.

R3.1. Studies must be performed for planning events to determine whether the system meets the performance requirements in Table 1 based on the Contingency list created in R3.4.

R3.2. Studies must be performed to assess the impact of the extreme events which are identified by the list created in R3.5.

R3.3. Contingency analyses for R3.1 & R3.2 must:

R3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses must include the impact of subsequent:

- Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.
- Tripping of Transmission elements where relay loadability limits are exceeded.
- Tripping of generation and other resources (including distributed resources) where ride-thru capabilities are exceeded

R3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

R3.4. Those planning events in Table 1, that are expected to produce more severe system impacts must be identified and a list of those Contingencies to be evaluated for system performance in R3.1 created. The rationale for those Contingencies selected for evaluation must be available as supporting information.

R3.5. Those extreme events in Table 1 that are expected to produce more severe system impacts must be identified and a list created of those events to be evaluated in R3.2. The rationale for those Contingencies selected for evaluation must be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) must be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, the BA must perform the Contingency analyses listed in

Table 1. The studies must be based on computer simulation models using data provided in Requirement R1.

R4.1. Studies must be performed for planning events to determine whether the system meets the performance requirements in Table 1 based on the Contingency list created in R4.4.

R4.1.1. For planning event P1: No generating unit must pull out of synchronism. A generator being disconnected from the system by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

R4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings must not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

R4.1.3. For planning events P1 through P7: Power oscillations must exhibit acceptable damping as established by the BA.

R4.2. Studies must be performed to assess the impact of the extreme events which are identified by the list created in R4.5.

R4.3. Contingency analyses for R4.1 and R4.2 must:

R4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses must include the impact of subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high-speed reclosing into a Fault where high speed reclosing is utilized.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.
- Tripping of all generation sources whose ride-thru capabilities are exceeded.

R4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static VAR compensators and power flow controllers.

R4.4. Those planning events in Table 1 that are expected to produce more severe system impacts on its portion of the system, must be identified, and a list created of those Contingencies to be evaluated in R4.1. The rationale for those Contingencies selected for evaluation must be available as supporting information.

R4.5. Those extreme events in Table 1 that are expected to produce more severe system impacts must be identified and a list created of those events to be evaluated in R4.2. The rationale for those Contingencies selected for evaluation must be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) must be conducted.

R5. The BA must have criteria for acceptable system steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its system. For transient voltage response, the criteria must at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.

R6. The BA must define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify system instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.

R7. The BA must distribute its Planning Assessment results to the Hawai'i PUC (or designee) within 30 calendar days upon a written request for the information.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

1. The system must remain stable. Cascading and uncontrolled islanding must not occur.
2. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
3. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
4. Simulate Normal Clearing unless otherwise specified.
5. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings
6. Phase angle separation for line contingency must not preclude automatic reclosing for BA groups B and C, unless system Adjustments can be performed within fifteen minutes.

Steady State Only:

7. Applicable Facility Ratings must not be exceeded.
8. System steady state voltages and post-Contingency voltage deviations must be within acceptable limits as established by the BA.
9. Planning event P0 is applicable to steady state only.
10. The response of voltage sensitive load that is disconnected from the system by end-user equipment associated with an event must not be used to meet steady state performance requirements.

Stability Only:

11. Transient voltage response must be within acceptable limits established by the BA.

Category	Initial Condition	Event[1]	Fault Type[2]	Non-Consequential Load Loss Allowed	Range of Customers Loss Allowed	Applicable BA Groups[3]
P0 No Contingency	Normal system	None	N/A	No	None	A, B, and C
P1 Single Contingency	Normal system	Loss of one of the following: 1. Generator 2. Transmission Circuits 3. Transformer[4] 4. Shunt Device-Ancillary Service Device[5] 5. Generator – no fault	3Ø and SLG for Events 1 through 4, N/A for Event	Yes	Up to 12% generation only	A
				Yes	Up to 15% generation only	B
				Yes	Up to 15% generation only	C

Table 1 – Steady State & Stability Performance Planning Events—Continued						
Category	**Initial Condition**	**Event**[1]	**Fault Type**[2]	**Non-Consequential Load Loss Allowed**	**Range of Customers Loss Allowed**	**Applicable BA Groups**[3]
P2 Single Contingency	Normal system	1. Opening a line section w/o fault[6]	N/A	No	None	A, B, and C
		2. Bus Section fault	SLG	Yes	none	A
				Yes	none	B
				Yes	none	C
		3. Internal Breaker Fault[7] (Transmission line breaker)	SLG	Yes	none	A
				Yes	none	B
				Yes	none	C
P3 Single Contingency	Loss of generator unit followed by System adjustments[8]	Loss of one of the following: 1. Generator 2. Transmission Circuits 3. Transformer[4] 4. Shunt Device/ Ancillary Service Device[5]	3Ø and SLG	No	up to 12%	A
				Yes	up to 40%	B
				Yes	up to 40%	C

Table 1 – Steady State & Stability Performance Planning Events—Continued						
Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Non-Consequential Load Loss Allowed**	**Range of Customers Loss Allowed**	**Applicable BA Groups[3]**
P4 Multiple Contingency (Fault plus stuck breaker[10])	Normal system	Loss of multiple elements caused by a stuck breaker[10] (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuits 3. Transformer[4] 4. Shunt Device[5] 5. Bus Section	SLG	Yes	Up to 65%	A
				Yes	Up to 65%	B[13]
				Yes	Up to 65%	C[13]
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie breaker) attempting to clear a Fault on the associated bus	SLG	Yes	Up to 65%	A[13]
				Yes	Up to 65%	B[13]
				Yes	Up to 65%	C[13]

Table 1 – Steady State & Stability Performance Planning Events—Continued						
Category	**Initial Condition**	**Event**[1]	**Fault Type**[2]	**Non-Consequential Load Loss Allowed**	**Range of Customers Loss Allowed**	**Applicable BA Groups**[3]
P5 Multiple Contingency (Fault plus relay failure to operate)	Normal system	Delayed Fault Clearing due to the failure of a non-redundant relay[12] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuits 3. Transformer[4] 4. Shunt Device[5] 5. Bus Section	SLG	No	None	A
				Yes	Up to 15%	B
				Yes	Up to 15%	C
P6 Multiple Contingency (Two overlapping singles)	Loss of one of the followed by system adjustments[8] 1. Transmission Circuits 2. Transformer[4] 3. Shunt Device[5]	Loss of one of the following: 1. Transmission Circuits 2. Transformer[4] 3. Shunt Device[5]	3Ø	No	Up to 40%	A
				Yes	Up to 65%	B[13]
				Yes	Up to 65%	C[13]
P7 Multiple Contingency (Common Structure)	Normal system	The loss of any two adjacent (vertically or horizontally) circuits on common wood structure[10]	SLG	No	Up to 40%	A
				Yes	Up to 65%	B
				Yes	Up to 65%	C

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

1. Simulate the removal of all elements that Protection systems and automatic controls are expected to disconnect for each Contingency.
2. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, shunt device, or transformer force out of service followed by another single generator, Transmission Circuit, shunt device, or transformer forced out of service prior to system adjustments.
2. Local area events affecting the transmission system such as:
   - **a.** Loss of a tower line with three or more circuits[10].
   - **b.** Loss of all Transmission lines on a common Right-of-Way[10].
   - **c.** Loss of a switching station or substation (loss of one voltage level plus transformers).
   - **d.** Loss of all generating units at a generating station.
   - **e.** Loss of a large load or major load center.
3. Wide area events affecting the Transmission System based on system topology such as:
   - **a.** Loss of two generating stations resulting from conditions such as:
     - **i.** Loss of a large fuel line into an area.
     - **ii.** Loss of the use of a large body of water as the cooling source for generation.
     - **iii.** Wildfires
     - **iv.** Severe weather, for example, hurricanes
     - **v.** A successful cyber attack
     - **vi.** Large earthquake, tsunami or volcanic eruption
   - **b.** Other events based upon operating experience that may result in wide area disturbances.

Stability

1. Loss of a single generator, Transmission circuit, shunt device, or transformer force out of service apply a 3Ø fault on another single generator, Transmission circuit, shunt device, or transformer prior to system adjustments.
2. Local area events affecting the transmission system such as:
   - **a.** 3Ø fault on generator with stuck breaker[9] or a relay failure[12] resulting in Delayed Fault Clearing.
   - **b.** 3Ø fault on Transmission circuit with stuck breaker[9] or a relay failure[12] resulting in Delayed Fault Clearing.
   - **c.** 3Ø fault on transformer with stuck breaker[9] or a relay failure[12] resulting in Delayed Fault Clearing.
   - **d.** 3Ø fault on bus section with stuck breaker[9] or a relay failure[12] resulting in Delayed Fault Clearing.
   - **e.** 3Ø internal breaker fault.
   - **f.** Other events based upon operating experience, such as consideration of initiating events that experience, such as consideration of initiating events that experience suggests may result in wide area disturbances.

Table 1 – Steady State & Stability Performance Footnotes (Planning Event and Extreme Events)
Footnotes

1. If the event analyzed involves system elements at multiple system voltage levels, the lowest system voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. The Applicable BA Groups (A, B or C) is defined under Facilities and is determined by the annual system peak demand.
4. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the system connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
5. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
6. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving load radial from a single source point.
7. An internal breaker fault means a breaker failing internally, thus creating a system fault which must be cleared by protection on both sides of the breaker.
8. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Transmission following Contingency events. System adjustment (as identified in the column entitled 'Initial Condition') when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
9. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
10. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
11. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to address System performance requirements. When Non-Consequential Load Loss is utilized within the planning process to address system performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated.
12. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32 & 67), and tripping (#86 & 94).
13. Indicates that the system level for the Category is an extreme event for the Group.

C. Measures

M1. The BA must provide evidence, in electronic or hard copy format, that it is maintaining system models within their respective area, using data consistent with HI-MOD-010 Development and Reporting of Steady State System Models and Simulations and HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations, including items represented in the Corrective Action Plan, representing projected system conditions, and that the models represent the required information in accordance with R1.

M2. The BA must provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the system in accordance with Requirement R2.

M3. The BA must provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. The BA must provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. The BA must provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable system steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its system in accordance with Requirement R5.

M6. The BA must provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify system instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. The BA must provide evidence, such as email notices, postal receipts showing recipient and date that it has distributed its Planning Assessment results to the Hawaiʻi PUC (or designee) within 30 calendar days upon a written request for the information in accordance with Requirement R7.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

Hawai'i PUC (or designee).

1.2. Data Retention:

The BA must each retain data or evidence to show compliance as identified unless directed by its Hawai'i PUC (or designee) to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable system steady state voltage limits, post-contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify system instability for conditions such as cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- Three calendar years of the notifications employed in accordance with Requirement R7 and Measure M7.

If the BA is found non-compliant, it must keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Processes:

- Compliance Audits: The Hawai'i PUC (or designee) will give notice to the BA within 30 days of years' end for a compliance audit and will complete such audit within 90 days of such information being supplied by the BA.
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

2. Levels of Non-Compliance for Requirement R1, Measure M1:

2.1. Level 1: The BA's system model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.5. for Requirement R1 and Measurement M1.

2.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.

3. Levels of Non-Compliance for Requirement R2, Measure M2:

3.1. Level 1: The BA failed to comply with Requirement R2, Part 2.6. for Requirement R2 and Measurement M2

3.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R2 and Measurement M2.

4. Levels of Non-Compliance for Requirement R3, Measure M3:

4.1. Level 1: The BA did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5. for Requirement R3 and Measurement M3.

4.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R3 and Measurement M3.

5. Levels of Non-Compliance for Requirement R4, Measure M4:

5.1. Level 1: The BA did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5 for Requirement R4 and Measurement M4.

5.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R4 and Measurement M4.

6. Levels of Non-Compliance for Requirement R5, Measure M5:

6.1. Level 1: N/A

6.2. Level 2: The BA does not have criteria for acceptable system steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its system for Requirement R5 and Measurement M5.

7. Levels of Non-Compliance for Requirement R6, Measure M6:

7.1. Level 1: N/A

7.2. Level 2: The BA failed to define and document the criteria or methodology for system instability used within its analysis as described in Requirement R6 for Requirement R6 and Measurement M6.

8. Levels of Non-Compliance for Requirement R7, Measure M7:

8.1. The BA distributed its Planning Assessment results to Hawaiʻi PUC (or designee) but it was more than 30 days but less than or equal to 40 days following the request as described in Requirement R7 for Requirement R7 and Measurement M7.

8.2. The BA failed to meet all the requirements of Level 1 for Requirement R7 and Measurement M7.

BAL-502-0: RESOURCE ADEQUACY ANALYSIS, ASSESSMENT, AND DOCUMENTATION

A. Introduction

Purpose: To establish common criteria for each Balancing Authority (BA) based on "one day in *x* year" (determined by study) loss of load expectation principles or as an alternative a planning methodology based on the single largest unit contingency and an appropriate reserve margin or reserve criteria. The analysis, assessment and documentation of Resource Adequacy, will include Planning Reserve Margins for meeting system load for the BA's system. The analysis will also include resource adequacy analysis for frequency response, spinning reserve, off-line reserves and other resource characteristics required to meet the reliability criteria.

Applicability: Balancing Authorities (BA) are divided into two groups based on the annual system Peak Demand.

- Group A: Annual system peak is greater than 50 MW.
- Group B: Annual system peak is less than or equal to 50 MW.

Effective Date: To be determined

B. Requirements

R1. The Group A utilities will establish at their discretion whether to use Resource Adequacy analysis using requirements defined in either R1.1 or R1.2 for each planning year. Group B will use the planning methodology defined in R1.2 for each planning year.

R1.1. Group A: "one day in *x* year criteria". The utility will establish the methodology and procedures used to establish the "one day in *x* year" criteria to meet the system peak load to be served by the BA. The methodology should evaluate the reliability of the generating resources, the capacity and system requirements of the BA and the alternatives to resource commitment available to meet the desired reliability criteria for each of the BA's utility loss of load expectations methodologies. In addition the methodology should include the consideration of, renewable capacity from as-available renewable resources using the reliability based methods described in R1.2 for L_{QC} . Consideration will also be given to ensure that the enough generating resources are installed on system that have the capability to provide the operating ancillary services such as frequency response, spinning reserve, voltage regulation, frequency regulation and other services during the same time periods included in HI-TPL-001 Transmission Planning Performance Requirements as follows:

R1.1.1. Minimum day load with no as-available renewable generation

R1.1.2. Minimum day load with as-available maximum renewable generation

R1.1.3. Maximum load with no as-available renewable generation

R1.1.4. Maximum load with maximum as-available renewable generation.

R1.2. Group A and Group B: "reserve margin of *xx*% criteria". The utility will maintain a minimum *xx*% Reserve Margin (F_{RM}) over the annual system peak.

$$\frac{\sum_{i=1}^{N} N_i + L_{DR} + L_{QC} - L_{Peak}}{L_{Peak} - L_{DR}} \geq F_{RM}$$

Where:

- F_{RM} is the Reserve Margin.
- N_i is the Normal Net Capability of all firm units.

- L_{DR} is the amount of Interruptible Demand and Direct Control Load Management (DCLM) exclusively available and measureable for the BA's interruption for the entire period of the expected capacity shortfall. Such Interruptible Demand and DCLM will not infringe on the protective reserve for system security required by HI-BAL-006 Underfrequency Load Shedding.
- L_{QC} is the estimated capacity value of grid-side as-available renewable and stored energy generation on the system. The estimated capacity value of grid-side as-available generation and stored energy will be determined by the utility using reliability or statistical based calculation methods depending upon the available data. Reliability based methods that may be used include the effective load carrying capability (ELCC), equivalent conventional power (ECP), or equivalent firm capacity (EFC) methods. Statistical based methods may consist of the relevant time period of the system peak and renewable energy over a time series of data. For example, the estimated capacity L_{QC} is the level where over that system peak period in which 90% of the data points are available to serve the system peak. For existing installations, the capacity value will be calculated using three years of actual data for each group of similar as-available renewables such as wind, hydro, PV, etc. For future installations the estimated capacity value will be based on estimated capacity value calculations for similarly located resources installed in Hawai'i. For future as-available resources where no Hawai'i historical data is available, the best available data shall be used for calculations. For the first year of data, the estimated capacity value shall be adjusted by 0.7 followed by 0.8 after gathering the second year of data. Following the third year of data, the actual data shall be used to determine the capacity value.
- L_{Peak} is the forecasted annual system peak load.

The Reserve Margin analysis will also consider as a secondary planning criteria that the BA's total Normal Net Capability of all firm units of the system less the capacity of the unit(s) scheduled for maintenance less the capacity that would be lost by the Forced Outage of the largest single contingency plus the total amount of interruptible loads plus the estimated capacity value of grid-side as-available renewable and stored energy generation on the system, if appropriate, and dedicated for serving the entire period of the peak ,must be equal to or greater than the forecasted system peak load.

$$\sum_{i=1}^{N} N_i - \sum_{m=1}^{N} N_m - N_{FO} + L_{DR} + L_{QC} \geq L_{Peak}$$

Where:

- N_m is the Normal Net Capability of units on scheduled maintenance.
- N_{FO} is the Normal Net Capability of the largest single contingency lost by Forced Outage.

R1.3. The BA for each Group A system will stipulate the use of either R1.1. or R1.2. for planning. The Resource Adequacy analysis must calculate a Planning Reserve Margin for the applicable group that will either result from the sum of the probabilities for Loss of Load for the system Peak Demand for all days of each planning year analyzed (per R1.1) being equal to *xx*. (This is comparable to a "one day in *x* year" criterion) or document that the applicable Balance Authority has developed a resource plan that encompasses a *xx*% Reserve Margin for Group A (per R1.2). Group B will use the Reserve Margin criteria (per R.1.2). The reserve margin target will be utilized until such a time that a new study determines a change in the reserve margin is warranted.

R1.4. The BA will develop criteria to ensure the generation characteristics address the following system requirements:

R1.4.1. Starting and loading time if resources are to be used as Contingency Reserves as required in HI-BAL-002 Disturbance Control Standard.

R1.4.2. The Frequency and Inertia response characteristics as required in HI-BAL-001 Transmission System Planning Performance Requirements.

R1.4.3. The Voltage and Frequency ride-through characteristics as required in HI-BAL-001 Transmission System Planning Performance Requirements.

R1.4.4. Short circuit current requirements.

R1.4.5. Dispatch characteristics (starting time, ramp rate, minimum values, regulation, etc.) as required to meet the requirements of the planning period.

R1.4.6. Any other ancillary resources required to meet system security requirements which have been identified as necessary through analysis of the planning period.

R1.5. Be performed or verified separately for each of the following planning years:

R1.5.1. Perform an analysis for Year One.

R1.5.2. Perform an analysis or verification when changes in measured non-dispatchable generation or net load changes more than *x* MW/year or *x* MW (amount established by each BA) from Year One or there are planned or unplanned changes in resource development other than nondispatchable generation or DG.

R1.6. Include the following subject matter and documentation of its use:

R1.6.1. Criteria for including planned resource additions in the analysis.

R1.6.2. Load forecast characteristics:

- Median forecast peak load.
- Load forecast uncertainty (reflects variability in the load forecast due to weather and regional economic forecasts).
- Load diversity.
- Seasonal load variations.
- Daily demand modeling assumptions (firm, interruptible).
- Contractual arrangements concerning curtailable or Interruptible Demand.
- Historic resource performance and any projected changes.

Seasonal resource ratings.

- Historic resource performance and any projected changes.

Seasonal resource ratings.

- Resource planned outage schedules, deratings, and retirements.
- Intermittent and energy limited resources such as wind, PV, and cogeneration may be considered holistically using time synchronized data with load. The relevant time period of the system peak must be defined using a minimum of three years of data.

R1.6.3. Transmission limitations that prevent the delivery of generation reserves.

R1.6.3.1. Criteria for including planned Transmission Facility additions in the analysis.

R1.6.3.2. Criteria for remedial action systems employed in lieu of Transmission improvements.

R1.7. Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

- Common mode outages that affect resource availability.
- Environmental or regulatory restrictions of resource availability.
- Any other demand (load) response programs not included in R1.3.1.
- Sensitivity to resource outage rates.
- Impacts of extreme weather or drought conditions that affect unit availability.

R1.8. Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis.

R2. The BA must annually document the projected load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.

R2.1. This documentation must cover each of the years in Year One through ten.

R2.2. This documentation must include the Planning Reserve Margin calculated per requirement R1.1 for each of the three years in the analysis.

R2.3. The documentation as specified per requirement R2.1 and R2.2 must be publicly posted no later than 30 days after the close of the year.

C. Measures

M1. The BA must possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1.

M2. The BA must possess the documentation of its projected load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1. Hawai'i PUC (or designee)

1.2. Compliance Monitoring Period and Reset Timeframe

1.2.1. One calendar year

1.3. Data Retention

1.3.1. The BA must retain information from the most current and prior two years. The Hawai'i PUC (or designee) will retain any audit data for five years.

2. Levels of Non-Compliance for Requirement R1, Measure M1:

2.1. Level 1: The BA met one of the following conditions for Requirement R1 and Measurement M1.

2.1.1. The BA Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under R1.4 and documentation of how and why they were included in the analysis or why they were not included.

2.1.2. The BA Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per R1.6.

2.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.

3. Levels of Non-Compliance for Requirement R2, Measure M2:

3.1. Level 1: The BA failed to publicly post the documents as specified per requirement R2.1 and R2.2 later than 30 calendar days prior to the beginning of Year One per R2.3 for Requirement R2 and Measurement M2.

3.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R2 and Measurement M2. The PUC or its designee will give notice to the BA within 30 days of years' end for a compliance audit and will complete such audit within 90 days of such information being supplied by the BA.

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N. System Operation and Transparency of Operations

PRUDENT DISPATCH AND OPERATIONAL PRACTICES

The Companies' unit commitment and economic dispatch policies are based on safe and reliable operation of the system, minimizing operating costs, and complying with contractual and regulatory obligations. The daily generation dispatch process is illustrated in Figure N-1.

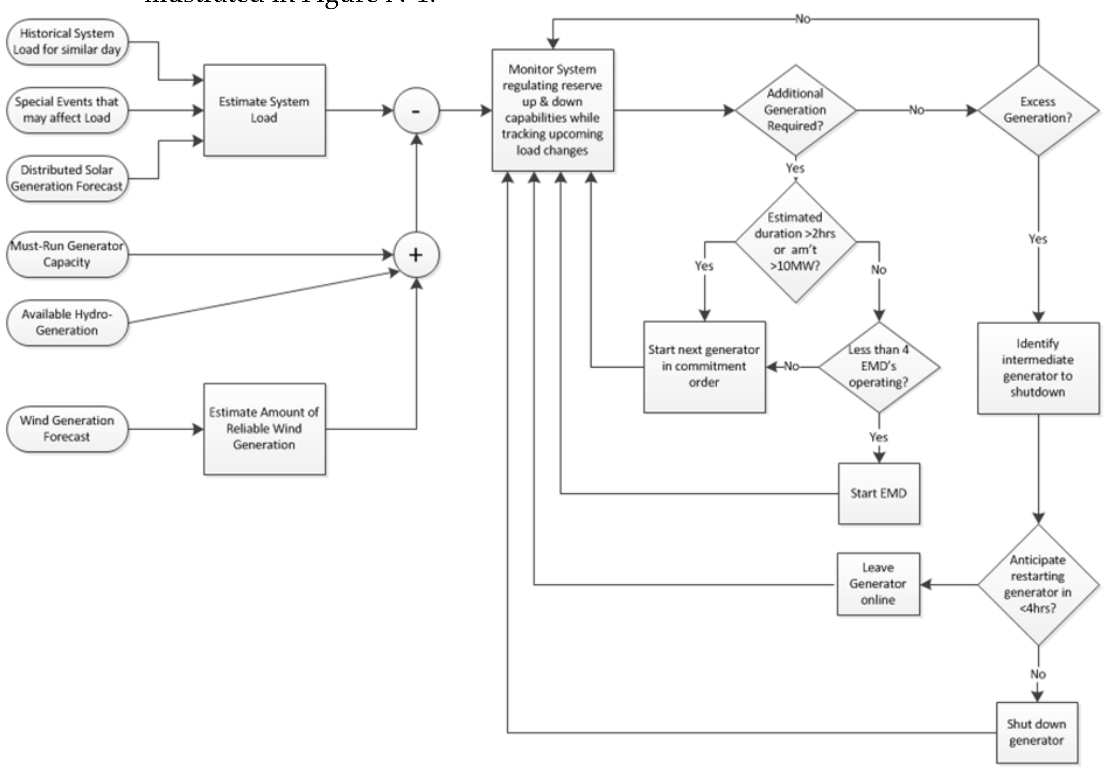

Figure N-1. Daily Generation Dispatch Process

In the future, the goal is for the System Operator to be able to incorporate a more automated approach to unit commitment and dispatch with increased amounts of variable renewable generation (wind and solar), quick-starting engines, energy storage, and demand response resources on the grid. The Energy Manage Systems (EMS) would likely be interfaced/integrated with corresponding Demand Response Management Systems (DRMS) and Energy Storage Management Systems (ESMS). This would also include integrating the demand forecast, with wind and solar forecasts to achieve a net demand to be used for unit commitment.

Minimization of Ancillary Services Costs

The process to identify system security constraints, and the combinations of resources which can be used to meet them, is summarized as follows:

- Determine system constraints.
- Identify the resource mix that meets each of them.
- Select the lowest cost combination of resources to operate.

For all three operating companies, additional security constraints are imposed with increased concentrations of variable renewable resources. Therefore, the projected increase in distributed PV may have an impact on ancillary service costs. The Companies will continually evaluate the economics of using existing resources to meet ancillary service and system security requirements versus meeting those needs with alternative resources including energy storage and demand response.

Maximizing the Use of Available Renewable Energy

The commitment and dispatch of renewable energy resources depends upon the contract terms for those resources and whether or not the system operator has visibility and control over the generation. If the resource can be economically dispatched, it is put under automatic generation control (AGC), and its output is determined by its marginal cost relative to the marginal cost of other resources. Examples of this type of renewable resource includes geothermal, generating units using renewable biofuels, waste-to-energy projects, and other “firm” renewable projects.

To date, variable renewable energy projects are contractually treated as “must-take,” variable energy. These resources are accepted regardless of cost, but their output is reduced as needed when all intermediate units are off line and there remains excess energy production. In this case the system operator limits, or “curtails” the output of variable energy providers to the degree necessary to keep the system in balance and provide response reserves. Most curtailments are partial—the output is limited but the resource is not restricted to zero output. When curtailment is necessary due to excess energy, it is performed in a manner consistent with the purchased power agreements associated with the affected resources and in accordance with a priority order established by the system operator.

In addition to excess energy situations, curtailments can also be required for system constraints such as line loading, phase angle separation, line maintenance, and frequency impact from power fluctuations. Curtailments for system constraints are applied to the resources as needed to address these constraints and are not subject to the priority order used for excess energy curtailments. Curtailments are also performed at the request of wind plants for wind conditions, and equipment issues. The number of curtailment events, the reason, and their duration are reported monthly through various reports to the Commission such as the monthly report filed by the Hawaiian Electric Companies in Docket No. 2011-0206 (RSWG).

The vast majority of distributed solar PV is not visible or controllable by the system operator. These resources serve demand ahead of all other resources. Additional growth in distributed solar PV these resources is forecast to cause increased curtailments of utility-scale variable renewable resources, unless distributed solar PV is required to provide the visibility and control to the system operator.

Energy Management Systems (EMS)

The operation of the system is facilitated by use of a centralized Energy Management System (EMS). The EMS provides the system operator with constantly updated, real-time information about the operational state of the system. There are three key program applications within the EMS:

- Supervisory Control and Data Acquisition (SCADA)
- Real-time Automatic Generation Control (AGC)
- Real-time State Estimator

The Companies routinely update the EMS hardware and software platforms for each system in order to ensure reliable operation, to incorporate new industry developments such as protocols and system security measures, and to maintain support from EMS vendors[1]. The most recent migration to a new platform was completed in late 2013.

[1] The Companies operate EMS systems from two different vendors, *Alstom* at Hawai'i Electric Light and Maui Electric, and *Siemens* at Hawaiian Electric.

System Dispatch and Unit Commitment

Unit commitment and dispatch decisions are based upon:

Safety. The Companies' dispatch of generating resources is always subject to ensuring the safety of Company personnel and the general public.

Reliability. Dispatch and unit commitment must adhere to system security and generation adequacy requirements.

Contractual Requirements. Dispatch and unit commitment must adhere to contractual constraints.

Cost. After meeting all the forgoing requirements, the Company commits units and dispatches units based on their marginal cost, with lower cost units being committed and operated before higher cost units.

When determining the unit commitment and dispatch of generating units, the Company does not differentiate between dispatchable IPPs and utility-owned assets. The daily unit commitment modeling tool input date does not differentiate units by ownership. Certain generators do receive a form of priority in terms of energy being accepted onto the system on the basis of the location of the generator, its characteristics, or the contractual obligations unique to the resource. The acceptance of energy is in the following order of preference:

- **Distributed generation:** Distributed generation resources receive preferential treatment as "must take" resources regardless of their economic merit for system dispatch. This includes Standard Interconnection Agreement (SIA) distributed generation and Net Energy Metering (NEM) distributed generation. At the present time, the Companies have no control over, or ability to curtail, distributed generation.
- **Scheduled contractually obligated generation:** These resources are preferentially treated from a dispatch perspective by contract. They are used to serve customer load regardless of their economic merit for system dispatch. Scheduled energy from these resources is taken after distributed generation, but ahead of all other resources including variable energy providers.
- **Contractually must-run, dispatchable generation:** The resources cannot be cycled offline and therefore the minimum dispatch level of these resources are preferentially treated in the system dispatch determination and the energy is accepted from these resources regardless of cost, except during periods of maintenance.
- **Generation to meet system security constraints:** These resources provide energy at least at their minimum dispatch limit, ahead of other resources, similar to contractual must-run and scheduled generation, plus an amount of reserve capability to provide down regulation. However, once dispatched, the continued operating status of these

resources is subject to continual evaluation of their costs relative to other alternative resources that may become available at a lower cost, except where it is required by contract.

- **Variable energy:** As available energy is accepted on the system, regardless of cost, after distributed generation, scheduled energy purchases, and continuously operated generation. This energy is accepted regardless of cost and thus presents a constraint on optimized (lowest) cost. If the energy cannot be accommodated due to low demand, curtailment of the resource is ordered according to an established and approved priority order.
- **Dispatchable resources:** Energy from dispatchable resources is taken on the basis of relative cost (economic dispatch). Resources with the lowest variable energy (fuel and O&M) cost will be committed ahead of resources with higher variable costs. Online resources with lower incremental costs will be dispatched at higher outputs ahead of resources with higher incremental costs. The units operated routinely to meet demand, but cycled offline during minimum demand periods, are described as intermediate units. Short-term (daily) unit commitment decisions do not consider fixed costs associated with these resources because the fixed costs will be incurred regardless of whether or not the unit is operated.

Utilization of Energy Storage and Demand Response

Energy storage and demand response programs can provide the system operator with a flexible resource capable of providing capacity and ancillary services. In order to provide the system operator with appropriate control and visibility of energy storage assets will be equipped with essentially the same telemetry and controls necessary to operate generating units. Demand response used for providing regulation reserves and contingency reserves will also be equipped with appropriate telemetry and controls. The specific interface requirements depend upon whether the storage device or demand response resource is responding automatically, or is under the control of the system operator. DRMS and/or ESMS may be interfaced with or directly incorporated in an EMS. For storage or demand response that is integrated into the EMS, telemetry requirements include:

- For storage, real-time telemetry indicating charging state, amount of energy being produced, device status.
- Control interface to the EMS to enable the increase and decrease of energy output from the storage asset, and for energy input to the storage device for charging.
- For demand response, real-time telemetry indicating breaker status, switch status, and load.

- Control interface to the EMS to enable the triggering of load shed in response to automatic signals (for example, underfrequency) or a command from the system operator.

Depending on the specific application, storage may also be required to respond to local signals. For example, storage may need the capability to respond to a system frequency change in a manner similar to generator governor droop response, which may be used for a contingency reserve response or for frequency responsive regulating reserve. Another example of local response includes the ability of the storage to change output (or absorb energy) in response to another input signal from a variable renewable energy resource in order to provide "smoothing" of the renewable resource output.

A special consideration of short-duration storage is the fact that it is a limited energy resource. This introduces the need for the system operator to be informed regarding the storage asset's charging state, and the need to ensure that the integration and operation of these resources allows for replacement energy sources prior to depletion of the storage. This replacement could be in the form of longer-term storage or generation resources. In order for the value of the demand response to be realized in providing a particular grid service, once called, the load cannot return to the system until after a specified time, which is dependent on the type of grid service being provided by the demand response resource. Accordingly, the system operator similarly requires information regarding the status of demand response, particularly as it relates to the state of the response after an event has been triggered.

Visibility and Transparency in System Dispatch

A high level review of the Renewable Watch websites of various ISOs including PJM, MISO, Cal ISO, and ERCOT shows the following operational information commonly being displayed, along with ISO energy market-specific information such as locational marginal pricing:

- Real time daily demand curve showing actual and forecasted demand, updated at least hourly
- Hourly wind power MW or MWh being produced and forecasted
- Other renewable energy production in MW (California)
- Available generation resources

The Company's Renewable Watch site currently displays the following information, with data updated approximately every 30 minutes:

Net Energy System Load. The system load served by generators on the "utility-side" of the meter including those owned by the utility and by independent power producers (IPP).

Gross System Load. The net system load plus estimated load served by "customer-side" of the meter by DG-PV.

Solar Irradiance Data. This data is measured in different regions of the island, which are used as input to calculating the estimated load served by customer-side PV.

Wind Power Production. Total megawatts of wind power being produced by the various IPP-owned wind farms selling electricity to Hawaiian Electric.

To provide further information to customers about the dispatch of various energy generation resources under the utility's control, the Company is currently partnering with the Blue Planet Foundation to develop and publicly present real time breakouts of the percentage of net energy system load being served by various fuel types, including coal, oil, wind, waste-to-energy, solar, and biofuel. Hawaiian Electric and Blue Planet believe this information will be useful in raising customer awareness of the use of renewable energy versus fossil fuels. A prototype kiosk was displayed at the Hawaiʻi Clean Energy Day event on July 22, 2014 with positive public reaction.

In light of this information already being developed for public display, Hawaiian Electric is agreeable to the following enhancements to its website:

- The information on the Renewable Energy watch website will be supplemented with additional information showing for the previous hour the percentage of the energy supplied by the different resources (IPPs, Renewables, Company generating units).
- A historical archive of the percentage of the energy produced by each of the resource groups for the previous 24 hour period will be maintained so that the customer can view the changes over time.

These enhancements will address the Commission's objectives of showing the significant use of non-utility generation and renewable resources, most of which, with the exception of Hawaiian Electric's biofueled combustion turbine generation CT-1, are IPP owned.

In addition to the above, Hawaiian Electric will also make public a description of its economic dispatch policies and procedures, via posting on its company website. Combined, the enhancements to the Hawaiian Electric website and the sharing of its dispatch policies and procedures will increase visibility and transparency of how generating resources are being dispatched on the Hawaiian Electric system.

As previously mentioned the Companies generating unit commitment and dispatch of the generating units is based on the objective of incurring the least cost to the customers while continuing to maintain system reliability. With the introduction of increasing amounts of renewable resources on the systems, it has become more important to minimize the use of fossil fuels and contending with the dynamic system changes that occur from the new resources so that reliability can be maintained. A screenshot from the Renewable Watch–O‘ahu website is shown below in Figure N-2 to provide an example of the variability of the renewable energy resources.

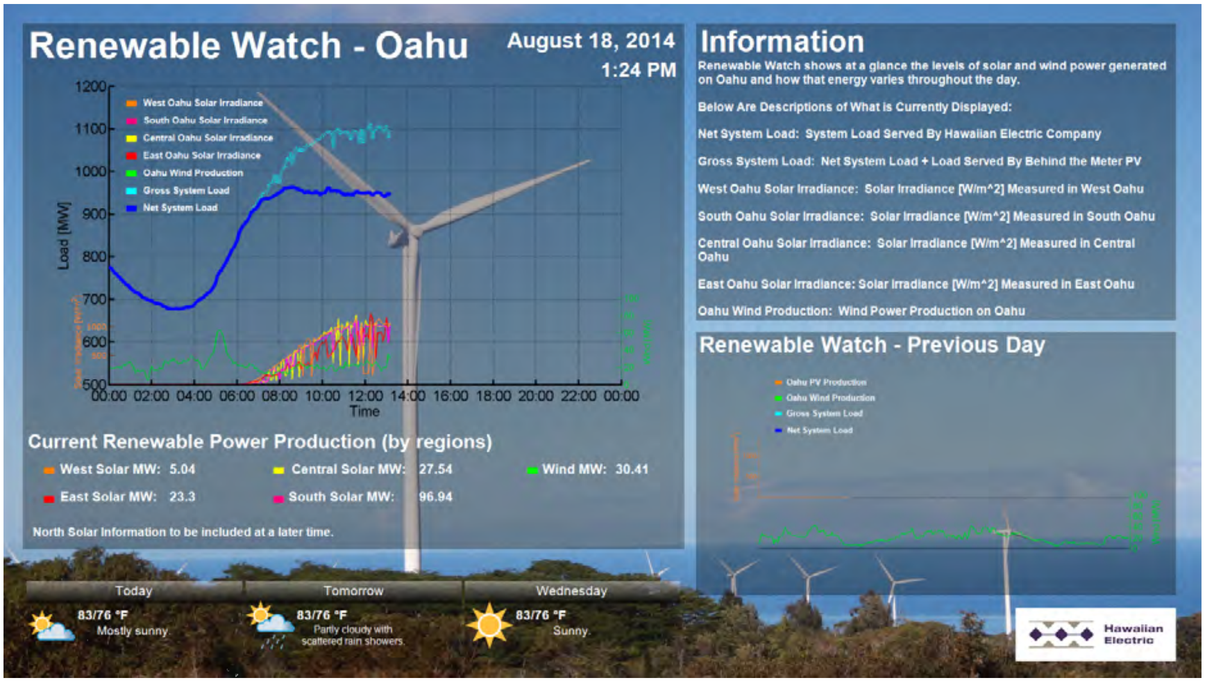

Figure N-2. Renewable Watch–O‘ahu Website Screenshot of Information Displayed for August 18, 2014.

Keep in mind that the changes that have been occurring on the Companies’ respective systems have been occurring for a few years but at different rates of change. The neighbor island systems (Maui and Hawai‘i Island) have been changing at a far more rapid pace due to the high availability of renewable resources that could be used on each island.

CAPACITY VALUE OF VARIABLE GENERATION AND DEMAND RESPONSE

Accurately assessing the capacity value of variable generation and demand response resources are critical components toward meeting customer demand and maintaining system reliability. Because wind and solar are variable resources, determining its capacity value becomes a considerable challenge in order to achieve the confidence required to include variable generation resources to replace firm generation.

Capacity Value of Wind Generation

Hawaiian Electric

The contribution of existing and future wind resources to capacity planning is reflected in the Loss of Load Probability (LOLP) analysis. In the modeling determination of when additional firm capacity may be needed based on the application of Hawaiian Electric's generating system reliability guideline (4.5 years per day), the wind resources' contribution to serving load will be reflected in the LOLP calculations. As such, wind resources' contribution to capacity planning is dependent upon the composition and assumptions in each plan.

Hawai'i Electric Light

The aggregate value of the two existing wind farms (20.5 MW Tawhiri wind generating facility and 10.56 MW Hawi Renewable Development wind farm) contribution to capacity planning is 3.1 MW.

The capacity value of future wind farms in the PSIP is 10% of the nameplate value of the facility to be added.

Maui Electric

The aggregate value of the three existing wind farms (20 MW Kaheawa Wind Power I, 21 MW Kaheawa Wind Power II, 21 MW Auwahi Wind Energy) contribution to capacity planning is 2 MW.

The capacity value of future wind farms in the PSIP is 3% of the nameplate value of the facility to be added.

Capacity Value of Solar Generation

The capacity value of existing and future utility-scale and rooftop PV is 0.

Capacity Value of Demand Response

The estimated megawatt potential from the Residential and Small Business Direct Load Control Program, Commercial and Industrial Direct Load Control Program, and Customer Firm Generation Programs are included in PISP capacity planning.

CONCLUSIONS

The Companies understand the importance of visibility and transparency of the economic commitment and economic dispatch to show the customers that a real effort is being made to reduce the use of fossil fuels and to encourage the use of renewable resources. Creating a website with the same information that RTOs or ISOs use to show price of energy for the market may be misleading if the customer is unaware of the system conditions that is dictating how the generating units are being run. The information that is graphically displayed on the existing Renewable Watch websites is a good starting point for creating visibility and transparency. And the Companies recommend that additional information that is being developed by Blue Planet that displays the system load and the percent of power that each resource group is providing to serve that load also be shown to the customers so that they are able to see over time that less fossil fuel generation is being substituted with less costly generation.

O. Diesel Generator Replacement Study

SUMMARY

Hawai‘i Electric Light utilizes ten stationary diesel generators (2.5 MW each) as peaking units. The diesel generators units are dispatched from the central control center at the KOCC in Hilo. The engines are kept in standby with the lube oil systems circulating with pre-lube pumps and heaters for fast start. These units can begin generating power within 2.5 minutes and are used for recovery when the variable generation assets generation drops down due to lack of wind.

The diesel generators are approximately 39 years old. The newest diesel is 27 years old and the oldest is 52 years. They have been maintained within the Original Equipment Manufacturers (OEM) recommendations. A study conducted in 2002 by Sargent & Lundy identified the existing diesel generators should be serviceable for an additional 20 to 30 years.

The machines have operated between 500 to 700 hours (each) per year and generated approximately 5,000 MWh (total) annually. The demand on the machines is projected to increase with the generation mix changes planned in the future and additional generation and run time will increase the demand on these units.

The diesel engines have been retrofitted in 2013 with current CO_2 removal catalyst and are compliant with current environmental regulations and should be able to operate an additional 20 to 30 years

The diesel generators have been very reliable for the past 39 years and with proper maintenance and rebuilds they can be expected to operate for at least an additional 20 years.

The economic evaluation was based on the following assumptions:

Option 1 – Maintain existing Diesel generators

- The diesel generators will be operable for the next 20 years with proper maintenance
- Fuel will be ultra low sulfur diesel
- Routine O&M will be based on historical levels
- Engine power pack replacements on a 6,000 hour cycle
- Complete engine rebuilds based on 16,000 hour cycles
- Heat rate on current equipment = 11,700 Btu/kWh

Option 2 – Replace ten (10) diesel generators

- New capital cost for a 2.5 MW diesel generator = $8,125,000
- Heat rate on new diesel generators = 8,500 Btu/kWh
- O&M routine and rebuild costs reduced

Based on these assumptions a 20 year present worth analysis was performed comparing operating and maintaining the existing diesel generators to purchasing and installing 10 new diesel generators (2.5 MW). The results indicated the maintaining the existing diesel generators would be the more economical solution.

Options	Generation MWh/Year	Heat rate Btu/kWh	Capital investment ($1,000)	Net Present Value ($1,000)
1. Current	5,000	11,446	$0	$36,198
2. Replace 10 diesels	5,000	8,500	$81,125	$156,214

Table O-1. Diesel Replacement Options

Based on the economic evaluation the operation of the existing diesel generators for the next 20 years is the lowest cost option for providing the system with peaking capacity.

BACKGROUND

As a part of the PSIP analysis the replacement of the existing ten (10) diesel generators was evaluated to determine if the replacement would reduce the operating costs for the diesel generators and reduce the cost to the customer.

There are ten (10) diesel generators rated at 2.5 MW each located at 3 sites. Table O-2 indicates the location, age, and heat rate for all the diesel generators.

Unit	Capability (MW)	Type	Operating Mode	Service Date	Age	Heat Rtae btu/kwhr
Kanoelehua D11	2.5	Diesel	Peaking	1962	52	11,864
Kanoelehua D15	2.5	Diesel	Peaking	1972	42	11,864
Kanoelehua D16	2.5	Diesel	Peaking	1972	42	11,864
Kanoelehua D17	2.5	Diesel	Peaking	1973	41	11,864
Waimea D12	2.5	Diesel	Peaking	1970	44	11,173
Waimea D13	2.5	Diesel	Peaking	1972	42	11,173
Waimea D14	2.5	Diesel	Peaking	1972	42	11,173
Keahole D21	2.5	Diesel	Peaking	1983	31	11,160
Keahole D22	2.5	Diesel	Peaking	1983	31	11,160
Keahole D23	2.5	Diesel	Peaking	1987	27	11,160

Table O-2. Generation Units Statistics (as of 2014)

Table O-3 details the heat rates of the diesel generators.

Diesel generator	Heat Rate			
Heat Rate	**2011**	**2012**	**2013**	**Average**
WAIMEA	11,557	11,117	10,845	**11,173**
KANOELEHUA	12,226	12,120	11,247	**11,864**
KEAHOLE	11,203	11,077	11,201	**11,160**
			Average	**11,446**

Table O-3. Diesel Generator Heat Rates

The reliability of the diesel generators has been very good for the past five years with an average reliability (Equivalent Availability Factor) of greater than 90% for three of the five years. The decline in 20112 and 2013 was from the installation of the CO_2 catalyst that required the diesel generators to be shut down for period of time to install the new equipment. The new catalyst has also been causing some derates on the units until the engines could be tuned and some engine power pack replacements could be installed.

Diesel Generator	Equiv Avail Factor (EAF)				
	2,014	2013	2012	2011	2010
Waimea D-12	95.2%	95.4%	89.5%	97.5%	97.7%
Waimea D-13	90.5%	73.4%	81.8%	94.4%	97.9%
Waimea D-14	95.3%	85.7%	86.1%	99.1%	98.3%
Kanoelehua D-11	99.5%	97.9%	79.3%	91.2%	99.9%
Kanoelehua D-15	98.5%	90.3%	87.1%	97.9%	99.8%
Kanoelehua D-16	99.1%	97.1%	84.9%	97.6%	99.8%
Kanoelehua D-17	82.3%	86.4%	84.3%	97.7%	99.7%
Keahole D-21	67.0%	67.8%	79.5%	97.0%	97.6%
Keahole D-22	93.2%	82.1%	97.3%	85.6%	77.3%
Keahole D-23	92.9%	71.0%	78.9%	97.5%	97.6%
Average	91.4%	84.7%	84.9%	95.6%	96.6%

Table O-4. Diesel Generator Equivalent Availability Factors

APPROACH

The economic evaluation compared two (2) options:

1. Maintain the existing ten (10) diesel generators
   - Heat rate assumption = 8,500 Btu/kWh
   - Fuel pricing based on 2014 Ultra Low Sulfur diesel prices
   - Routine maintenance costs were based on the 2013 routine costs
     - PM work on the engines monthly
     - Added in 2013 – CO_2 catalyst monitoring
   - Power Pack replacements
     - The engine power pack replacements are based on 6,000 hours of service
     - Replacements are required to maintain engine efficiency
     - Visible emissions were affected by catalyst additions as engines deteriorate so the power pack frequency has increased. The cost is approximately $175,000 per engine per replacement
   - Engine overhauls – complete
     - Power pack replacement
     - Engine removal – shop disassemble and reassemble
     - Line bore engine valve train
     - Repair any engine block cracking

    - Cost is approximately $565,900 each rebuild
    - Frequency is every 16,000 hours
- Operating assumptions
- Projected service hours to be 500–700 hours per year per engine
    - Estimated 5,000 MWh to generation per engine per year; based on PSIP projected run times and added contingency for uncertainty in modeling projections
- Heat Rate for all engines averages 11,446 Btu/kWh

Cost assumptions are included in Table O-5.

2. Replace ten diesel generators with new

- Assumed new installations will be in 2020
- Heat rate assumption = 8,500 Btu/kWh
- Fuel pricing based on 2014 ultra low sulfur diesel prices
- Estimated cost is based on ENRAL pricing
    - 2.5mw diesel generators
    - $3,250 / kW installed
    - Price per diesel generator = $8,125,000
    - Total capital investment for 10 diesel denerators = $81,125,000
- Routine maintenance costs were based on the 2013 routine costs
    - PM work on the engines monthly
    - PM work is similar for new engines
- Power pack replacements will be less frequent
    - Power pack replacements will begin in 2027
- Engine overhauls – complete
    - Non required in evaluation period

The economic evaluation was based on comparison of the two cases over a 20 year period The net present value (NPV) of the cost to operate and maintain the two options were developed. The lowest NPV of cost would be the best option.

RESULTS

The expected mission of the diesel generators for the next 16 years (based on the PSIP) should be similar to the past. They will be utilized as peaking units as well as fast start assets when there is a system disturbance or loss of a generating unit. The function in these cases will be to restore the voltage and frequency of the system

The exiting ten diesel generators have been maintained with an acceptable level of reliability (greater than 90%) and should be able to be maintained at that level for the next 20 years with proper maintenance, power pack replacements and engine rebuilds.

The results of the economic evaluation indicates the cost to maintain the diesel generators is far less than the cost for installing new similar sized diesel generators. The primary differences in NPV is driven by the capital investment for the new engines being far greater the savings from the lower operating and maintenance costs. Table O-6 shows the net present value analysis.

UNIT	Net Maximum Capacity	O&M Routine															
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
		$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year
Waimea D-12 (emd diesel)	2.50	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Waimea D-13 (emd diesel)	2.50	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Waimea D-14 (emd diesel)	2.50	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Kanoelehua D-11 (fairbank morris dsl)	2.00	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Kanoelehua D-15 (emd diesel)	2.50	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Kanoelehua D-16 (emd diesel)	2.50	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Kanoelehua D-17 (emd diesel)	2.50	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Keahole D-21 (emd diesel)	2.50	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Keahole D-22 (emd diesel)	2.50	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Keahole D-23 (emd diesel)	2.50	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Panaewa D-24 (cummins diesel)	1.00																
Ouli D-25 (cummins diesel)	1.00																
Punaluu D-26 (cummins diesel)	1.00																
Kapua D-27 (cummins diesel)	1.00																
Routine O&M	**Total**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**

UNIT	Net Maximum Capacity	Engine power pack replacement															
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
		$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year
Waimea D-12 (emd diesel)	2.50	$ 174,000											$ 170,000				
Waimea D-13 (emd diesel)	2.50						$ 174,000										
Waimea D-14 (emd diesel)	2.50	$ 174,000						$ 174,000									
Kanoelehua D-11 (fairbank morris dsl)	2.00																
Kanoelehua D-15 (emd diesel)	2.50			$ 174,000					$ 174,000								
Kanoelehua D-16 (emd diesel)	2.50			$ 174,000					$ 174,000								
Kanoelehua D-17 (emd diesel)	2.50				$ 174,000									$ 174,000			
Keahole D-21 (emd diesel)	2.50	$ 174,000											$ 174,000				$ 174,000
Keahole D-22 (emd diesel)	2.50						$ 174,000					$ 174,000					
Keahole D-23 (emd diesel)	2.50					$ 174,000					$ 174,000						$ 174,000
Panaewa D-24 (cummins diesel)	1.00																
Ouli D-25 (cummins diesel)	1.00															$ 174,000	
Punaluu D-26 (cummins diesel)	1.00															$ 174,000	
Kapua D-27 (cummins diesel)	1.00																$ 174,000
																	174000
Routine O&M	**Total**	**$ 522,000**	**$ -**	**$ 348,000**	**$ 174,000**	**$ 174,000**	**$ 348,000**	**$ 174,000**	**$ 348,000**	**$ -**	**$ 174,000**	**$ 174,000**	**$ 344,000**	**$ 174,000**	**$ -**	**$ 348,000**	**$ 522,000**

UNIT	Net Maximum Capacity	Engine / Generator complete rebuild															
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
		$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year
Waimea D-12 (emd diesel)	2.50							$ 565,000									
Waimea D-13 (emd diesel)	2.50											$ 565,000					
Waimea D-14 (emd diesel)	2.50												$ 565,000				
Kanoelehua D-11 (fairbank morris dsl)	2.00																
Kanoelehua D-15 (emd diesel)	2.50														$ 565,000		
Kanoelehua D-16 (emd diesel)	2.50														$ 565,000		
Kanoelehua D-17 (emd diesel)	2.50								$ 565,000				$ 565,000				
Keahole D-21 (emd diesel)	2.50									$ 565,000			$ 565,000				
Keahole D-22 (emd diesel)	2.50									$ 565,000							
Keahole D-23 (emd diesel)	2.50														$ 565,000		
Panaewa D-24 (cummins diesel)	1.00																
Ouli D-25 (cummins diesel)	1.00																
Punaluu D-26 (cummins diesel)	1.00																
Kapua D-27 (cummins diesel)	1.00																
Routine O&M	**Total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 565,000**	**$ 565,000**	**$1,130,000**	**$ -**	**$ 565,000**	**$1,695,000**	**$ -**	**$1,695,000**	**$ -**	**$ -**

Table O-5. Current Plan Maintenance Costs

Capital rplacement of diesel generators

Costs	Resp	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Cost ($)															
Routine O&M		$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000
Power pack replacement		$ 522,000	$ -	$ 348,000	$ 174,000		$ 348,000	$ 174,000	$ 348,000	$ -	$ 174,000	$ 174,000	$ 344,000	$ 174,000	$ -
Overhauls		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Escallation	1	1.03	1.06	1.09	1.12	1.15	1.18	1.21	1.24	1.27	1.3	1.34	1.38	1.43
Total cost impact	$	1,272,000	772,500	1,163,880	1,007,160	840,000	1,262,700	1,090,320	1,328,580	930,000	1,173,480	1,201,200	1,465,960	1,275,120	1,072,500
Generation	mwhr	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Heat rate	btu/kwhr	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500
Heat input	mbtu	42,500	42,500	42,500	42,500	42,500	42,500	42,500	42,500	42,500	42,500	42,500	42,500	42,500	42,500
Fuel costs	$/mbtui	22.73	22.72	22.28	22.26	22.74	23.51	24.38	25.36	26.37	27.45	28.52	29.57	30.57	31.72
Fuel costs	$	$ 965,967	$ 965,406	$ 946,725	$ 945,855	$ 966,480	$ 999,280	$ 1,036,297	$ 1,077,600	$ 1,120,653	$ 1,166,493	$ 1,212,059	$ 1,256,934	$ 1,299,257	$ 1,348,294
Revenue Requirements						11,271,179	15,376,947	14,599,104	13,862,543	13,163,136	12,497,443	11,855,372	11,220,870	10,586,139	9,951,407
Total Costs		$ 2,237,967.06	$ 1,737,906	$ 2,110,605	$ 1,953,015	$ 13,077,658	$ 17,638,928	$ 16,725,721	$ 16,268,723	$ 15,213,789	$ 14,837,416	$ 14,268,631	$ 13,943,765	$ 13,160,515	$ 12,372,201
Escalation factor		1	1.03	1.06	1.09	1.12	1.15	1.18	1.21	1.24	1.27	1.3	1.34	1.38	1.43
Escallated cost		$ 2,237,967	$ 1,790,043	$ 2,237,242	$ 2,128,787	$ 14,646,977	$ 20,284,767	$ 19,736,351	$ 19,685,155	$ 18,865,098	$ 18,843,518	$ 18,549,220	$ 18,684,644	$ 18,161,511	$ 17,692,247
Discount Factor		1.000	0.934	0.872	0.814	0.761	0.710	0.663	0.620	0.579	0.540	0.505	0.471	0.440	0.411
Discounted Cost		$ 2,237,967	$ 1,671,687	$ 1,951,175	$ 1,733,832	$ 11,140,753	$ 14,408,813	$ 13,092,322	$ 12,194,958	$ 10,914,207	$ 10,180,913	$ 9,359,271	$ 8,804,260	$ 7,991,929	$ 7,270,668
NPV benefit	**$ 158,181,829**	0.448	0.358	0.447	0.426	2.929	4.057	3.947	3.937	3.773	3.769	3.710	3.737	3.632	3.538

Current operation

Costs	Resp	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Cost ($)															
Routine O&M		$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000
Power pack replacement		$ 522,000	$ -	$ 348,000	$ 174,000	$ 174,000	$ 348,000	$ 174,000	$ 348,000	$ -	$ 174,000	$ 174,000	$ 344,000	$ 174,000	$ -
Overhauls		$ -	$ -	$ -	$ -	$ -	$ -	$ 565,000	$ 565,000	$ 1,130,000	$ -	$ 565,000	$ 1,695,000	$ -	$ 1,695,000
	Escalation	1	1.03	1.06	1.09	1.12	1.15	1.18	1.21	1.24	1.27	1.3	1.34	1.38	1.43
Total cost impact	$	1,272,000	772,500	1,163,880	1,007,160	1,034,880	1,262,700	1,757,020	2,012,230	2,331,200	1,173,480	1,935,700	3,737,260	1,275,120	3,496,350
Generation	mwhr	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Heat rate	btu/kwhr	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700
Heat input	mbtu	58,500	58,500	58,500	58,500	58,500	58,500	58,500	58,500	58,500	58,500	58,500	58,500	58,500	58,500
Fuel costs	$/mbtui	22.73	22.72	22.28	22.26	22.74	23.51	24.38	25.36	26.37	27.45	28.52	29.57	30.57	31.72
Fuel costs	$	$ 1,329,625	$ 1,328,852	$ 1,303,140	$ 1,301,942	$ 1,330,331	$ 1,375,480	$ 1,426,432	$ 1,483,284	$ 1,542,545	$ 1,605,643	$ 1,668,363	$ 1,730,133	$ 1,788,389	$ 1,855,887
Revenue Requirements		0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Costs		$ 2,601,625.25	$ 2,101,352	$ 2,467,020	$ 2,309,102	$ 2,365,211	$ 2,638,180	$ 3,183,452	$ 3,495,514	$ 3,873,745	$ 2,779,123	$ 3,604,063	$ 5,467,393	$ 3,063,509	$ 5,352,237
Escalation factor		1	1	1	1	1	1	1	1	1	1	1	1	1	1
Escallated cost		$ 2,601,625	$ 2,101,352	$ 2,467,020	$ 2,309,102	$ 2,365,211	$ 2,638,180	$ 3,183,452	$ 3,495,514	$ 3,873,745	$ 2,779,123	$ 3,604,063	$ 5,467,393	$ 3,063,509	$ 5,352,237
Discount Factor		1.000	0.934	0.872	0.814	0.761	0.710	0.663	0.620	0.579	0.540	0.505	0.471	0.440	0.411
Discounted Cost		$ 2,601,625	$ 1,962,413	$ 2,151,572	$ 1,880,693	$ 1,799,022	$ 1,873,970	$ 2,111,777	$ 2,165,472	$ 2,241,115	$ 1,501,525	$ 1,818,481	$ 2,576,252	$ 1,348,090	$ 2,199,513
NPV benefit	**$ 36,554,184**	0.520	0.420	0.493	0.462	0.473	0.528	0.637	0.699	0.775	0.556	0.721	1.093	0.613	1.070

Table O-6. Net Present Value Analysis

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