Maui Electric Power Supply Improvement Plan

August 2014

Hawaiian Electric
Maui Electric
Hawaiʻi Electric Light

Maui Electric submits this Power Supply Improvement Plan to comply with the Decision and Order issued by the Hawai'i Public Utilities Commission on April 28, 2014 in Docket No. 2011-0092, Order No. 32055. 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 Maui Electric'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 Maui County, the PSIP increases renewable content of electricity to approximately 72% by 2030, and reduces full service residential customer bills, on average, by 28% 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 by 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 only 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 Maui County, the Maui Electric Preferred Plan increases the already aggressive RPS from 45% in 2015 to 72% in 2030. A significant amount of market-based, distributed solar photovoltaics (PV) is included in the Preferred Plan and accounts for about one-third of this total.

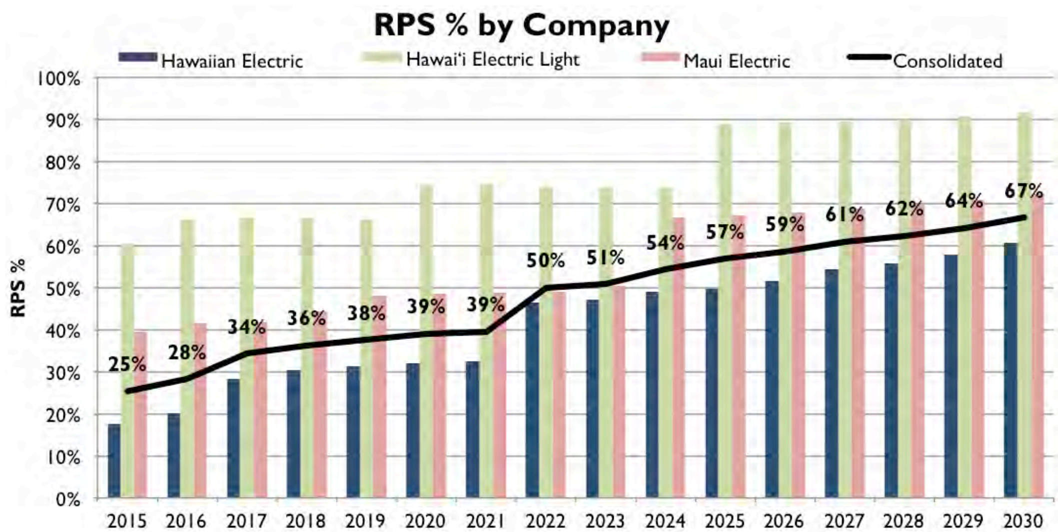

Figure ES-1. Renewable Portfolio Standard (RPS) for the Hawaiian Electric, Maui Electric, Hawai‘i Electric Light, and the Consolidated Companies, 2015-2030.

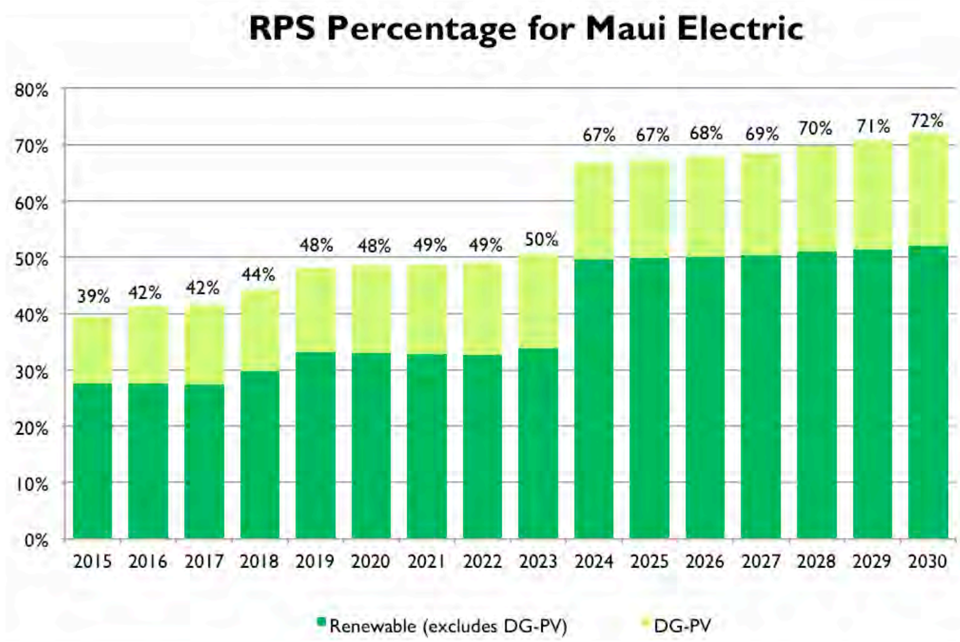

Figure ES-2. Renewable Portfolio Standard (RPS) for Maui Electric on Maui, Lana'i, and Moloka'i, 2015-2030, showing the relative contribution from distributed generation (DG-PV)

Maximizes Utilization of Renewable Energy

From 2015 through 2030, 95.8% to 99.2% of the estimated energy produced from all renewable resources would be utilized (not curtailed) each year (Figure ES-3). 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 planning period.
- Reducing the "must-run" requirements of thermal generators.

% RE Utilized	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2015-2030
	98.3%	97.0%	98.2%	98.4%	98.2%	98.3%	98.2%	98.1%	97.9%	99.2%	99.1%	98.9%	98.7%	98.5%	98.2%	97.9%	98.4%

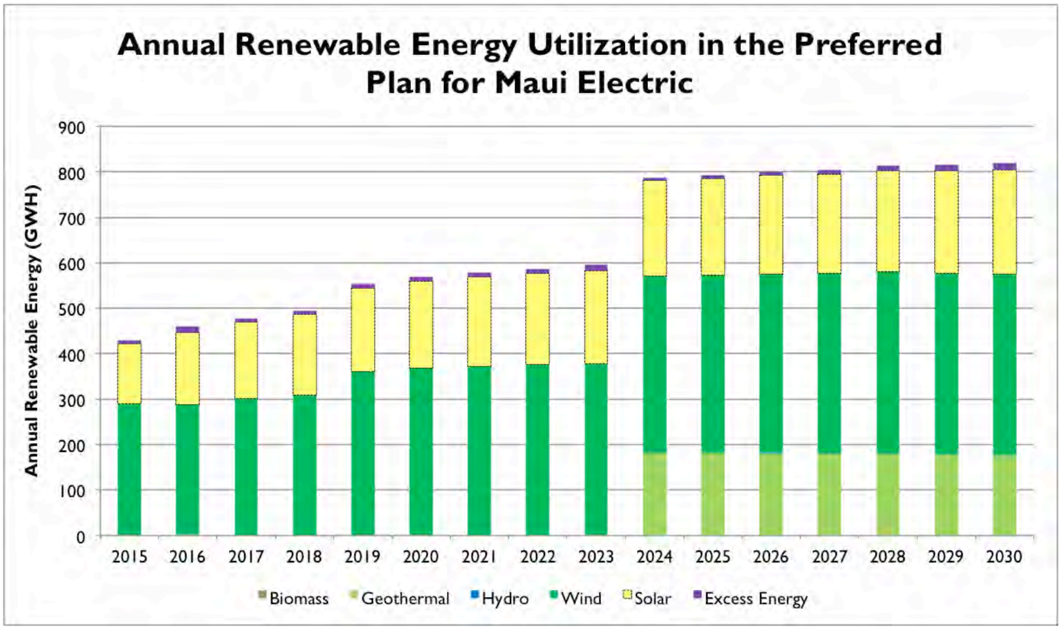

Figure ES-3. Total System Renewable Energy Utilized by Maui Electric (Maui)

The Preferred Plan Provides a Hedge Against Fuel Price Volatility

In developing the Preferred Plan, conscious choices were made to blend resources that move the generation mix away from fossil-fuel resources. This was done, in part, to provide a financial hedge against fuel price volatility and future uncertainty with respect to fuel availability.

Generally, 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 determining factor for some resource selections. Accordingly, renewable resources that consume no fuel were selected for the PSIP in some cases where they were not the obvious low-cost option. The selections of new generation resources for inclusion in the Preferred Plan were based on economics, planning flexibility, and operational flexibility.

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 make valuable contributions.

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[1] As defined in the *Integrated Demand Response Portfolio Plan* (IDRPP), filed by the Companies on July 28, 2014, in Docket No. 2007-0341.

OVERVIEW OF THE PREFERRED PLAN

Energy Mix

Figure ES-4 illustrates the energy mix for Maui from 2015 to 2030. Renewable energy from distributed PV continues to grow over time; new utility-scale wind is also added to the system. As firm generating units are deactivated and decommissioned, new flexible firm generation is added in its place. Oil is replaced by liquefied natural gas (LNG), and a portion of the coal is replaced by biomass.

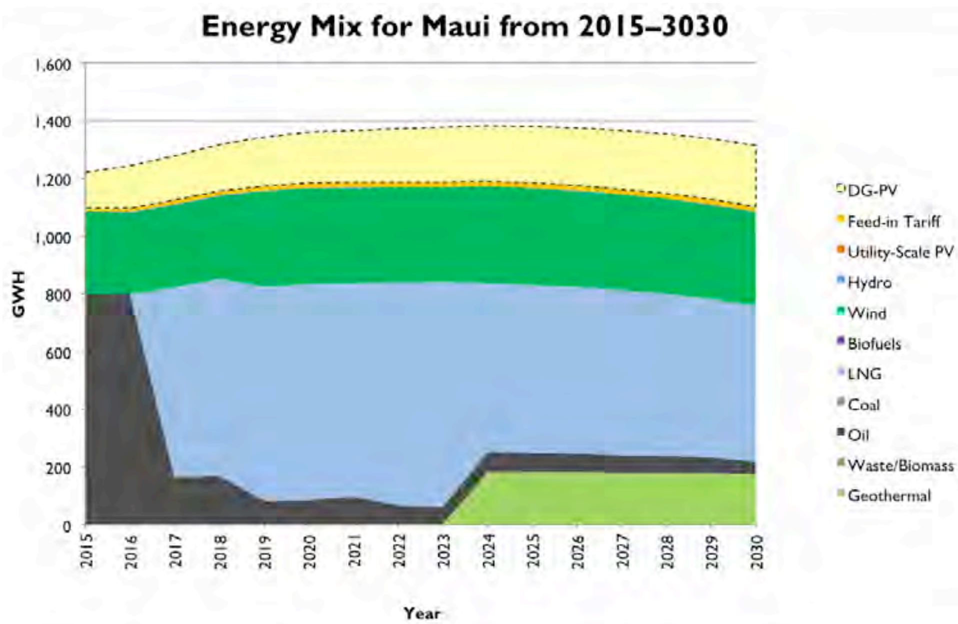

Figure ES-4. Annual Energy Mix of Maui Electric Preferred Plan

The Preferred Plan for Maui Island for 2015–2030 can be summarized as follows:

- Increases distributed generation three-fold.
- Switches fuel at certain units to meet new environmental regulations.
- Procures lower cost LNG, and modifies certain generating units to utilize LNG as a fuel.
- Retires existing thermal generation through the 2019–2030 time period.
- Installs new Internal Combustion Engine (ICE) generators in South Maui fired with ultra low sulfur diesel (ULSD) fuel (a Non-Transmission Alternative, avoiding a new South Maui overhead transmission line), and at the Waena site fired with LNG.
- Adds wind generation early in the plan.
- Installs energy storage for regulating and contingency reserves.

- Relocates, at a later time, the ICE generators from South Maui to Waena and converts those ICE generators to LNG.
- Adds a geothermal plant in 2024.
- Upgrades the Central Maui transmission line in 2018.
- Aggressively expands demand response programs.
- Modernizes the grid with smart technologies.

The Preferred Plans for Lana‘i and Moloka‘i for 2015–2030 can be summarized as follows:

- Switches to 50% LNG fuel in 2017.
- Switches to 50% biodiesel fuel, decreasing cost below that of ultra low sulfur diesel (ULSD).
- Installs utility-scale solar in 2018.
- Installs large-scale energy storage in 2018.

Timelines for the Preferred Plan

Figure ES-5 illustrates the timelines for the Preferred Plans for the Maui Electric power system on Maui for 2015–2030. It shows when new resources would be added (above the date line) and existing resources would be retired (below the date line). Similarly, Figure ES-6 shows the Preferred Plan for Maui Electric’s Moloka‘i system for 2015–2030; Figure ES-7 shows the Preferred Plan for Maui Electric’s Lana‘i system for 2015–2030.

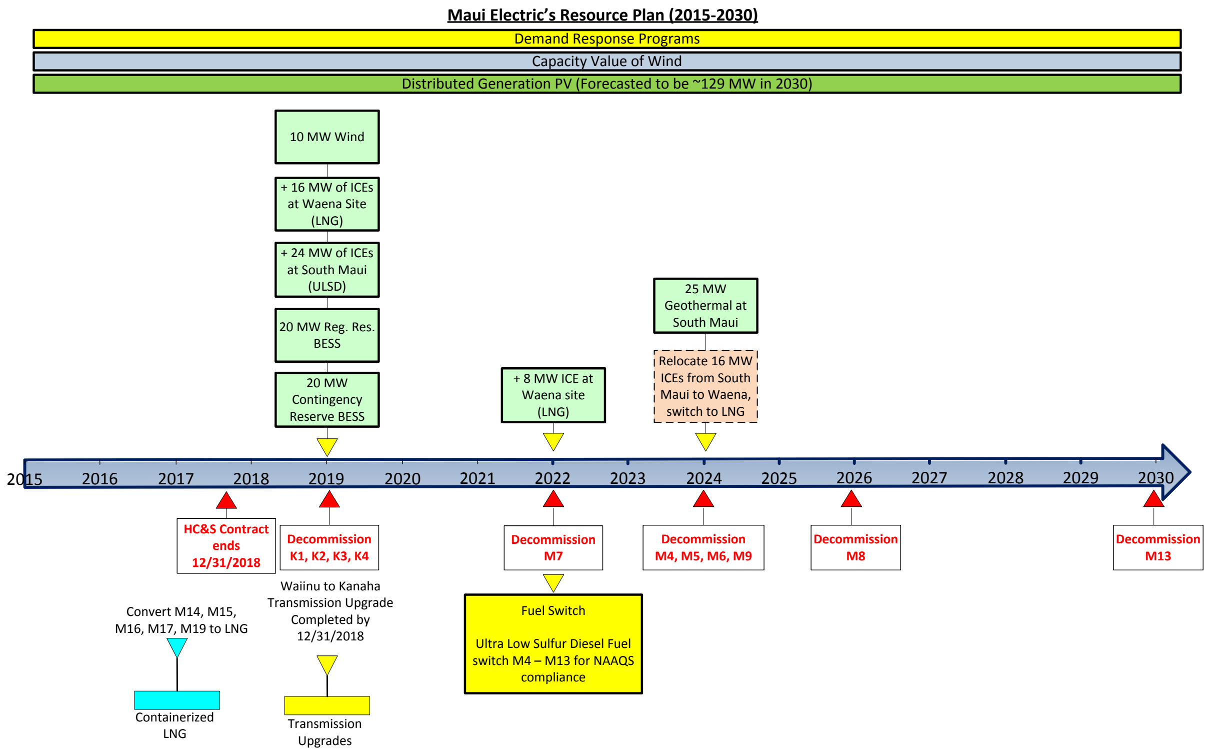

Figure ES-5. Maui Electric Preferred Plan 2015-2030 (Maui Island)

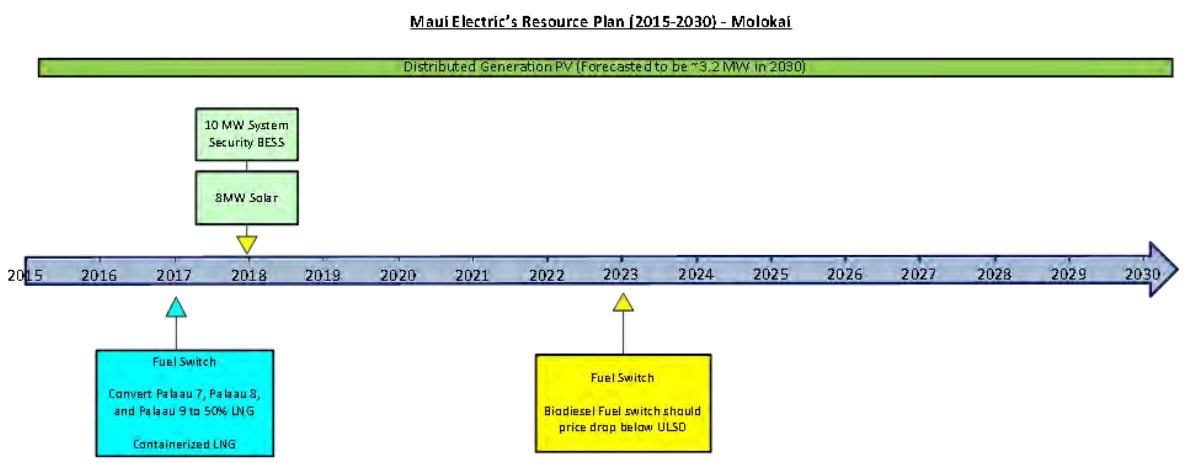

Figure ES-6. Maui Electric Preferred Plan 2015-2030 (Moloka'i)

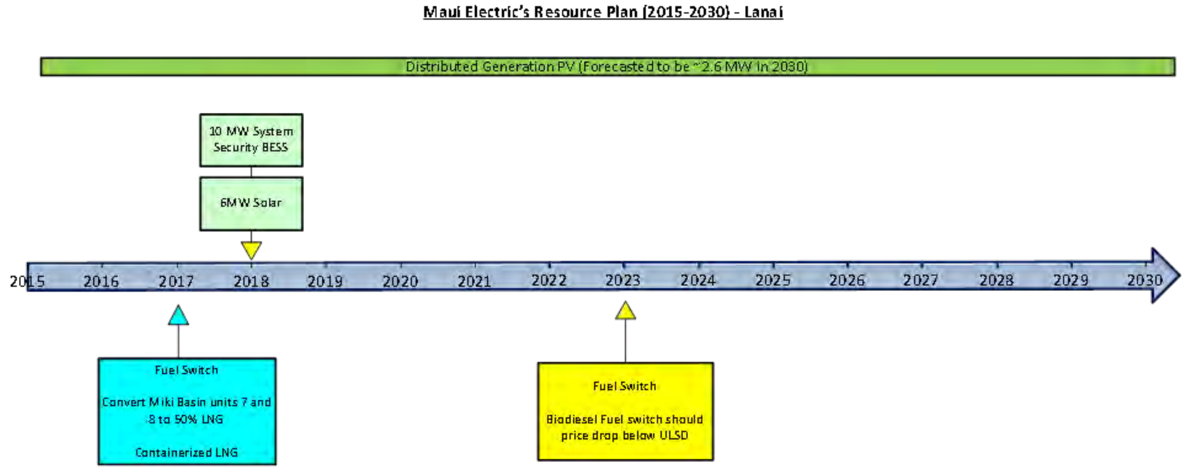

Figure ES-7. Maui Electric Preferred Plan 2015-2030 (Lana‘i)

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 on Maui, Moloka‘i and Lana‘i 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 28% from 2014 to 2030 (Figure ES-8).

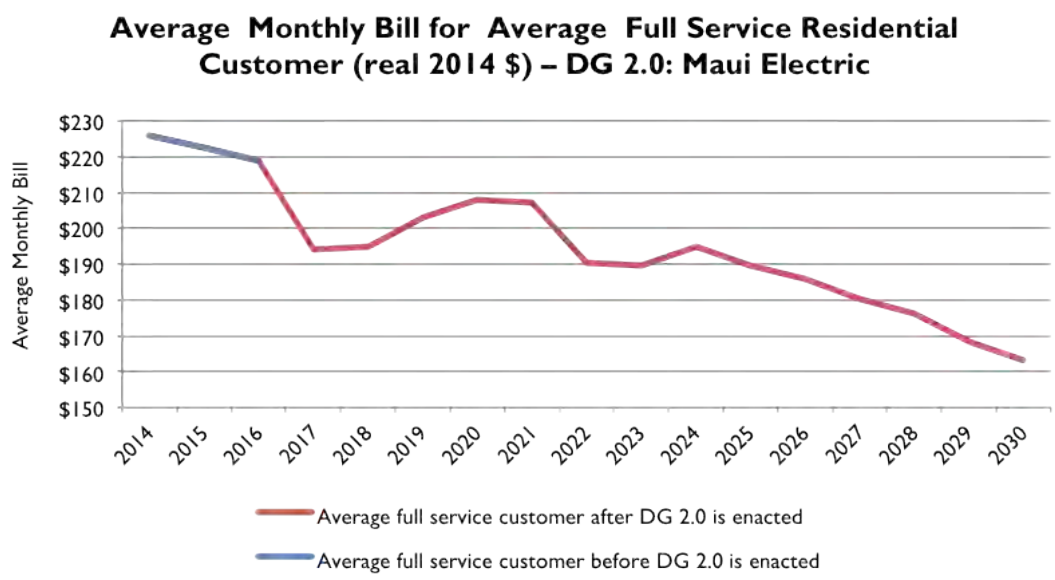

Figure ES-8. Average Full Service Residential Customer Bill Impact: Maui Electric

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 selected thermal generation resources exhibit a high degree of operational flexibility across a wide range of duty-cycles and system conditions.

Technological Flexibility: The Preferred Plan can be immediately implemented using proven technologies that are available today. The Preferred Plan, however, is also 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.

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, fair, and assumptions that support near term actions.

EXECUTION OF THE PREFERRED PLAN

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

The Preferred Plan identifies near-term actions that must be initiated on the path toward a realization of 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.

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 1-9 shows this trend on the Maui Electric 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 for Maui Electric, but is also relevant for the Hawaiian Electric and Hawai'i Electric Light power systems.

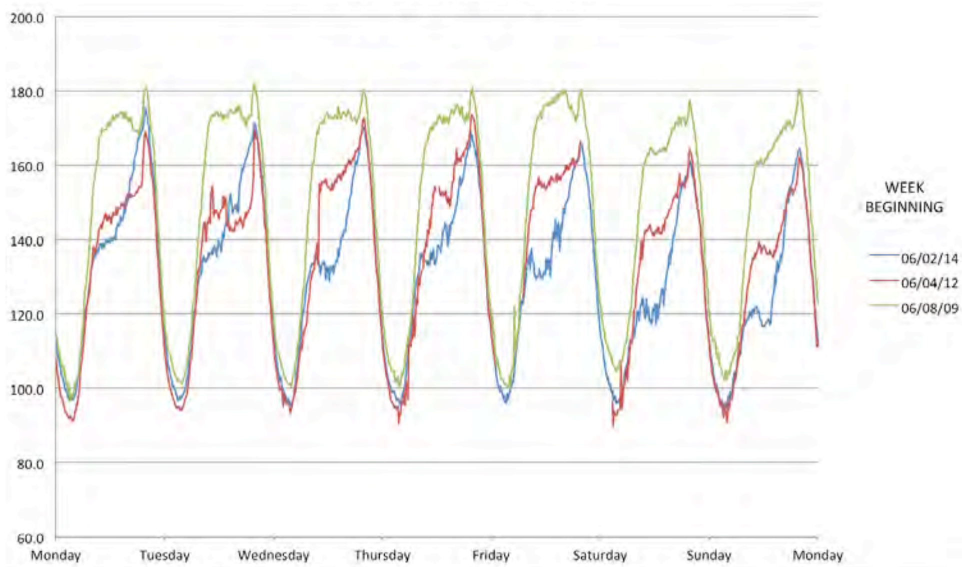

Figure 1-9. Maui Electric System Load Profiles, 2006–2014

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

- Daytime peak loads on the Maui Electric 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.

Stakeholder Engagement

Our approach toward achieving heightened visibility is to boldly and vigorously engage with our customers and the community we serve. In order to increase our awareness of and ability to meet the expectations of our customers and our community, Maui Electric recently sought input from key stakeholders representing County government, community organizations, environmental interest groups, and employees on their perspectives on what energy could look like for Maui. These outreach efforts provided us with valuable insight on the preferences, concerns, and economic and social values of our customers, creating a tremendous opportunity to better align our operational and educational efforts with stakeholders.

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 Hawaiʻi. 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 Hawaiʻi.

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 Hawaiʻi's economy and environment, and making Hawaiʻi a leader in the nation's energy transformation. Hawaiʻi 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 Hawai‘i 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 Hawai‘i, 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.** Hawai‘i 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 Hawai‘i’s remoteness and lack of interconnections, we must have an

[3] See “Commission’s Inclinations on the Future of Hawai‘i’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.**

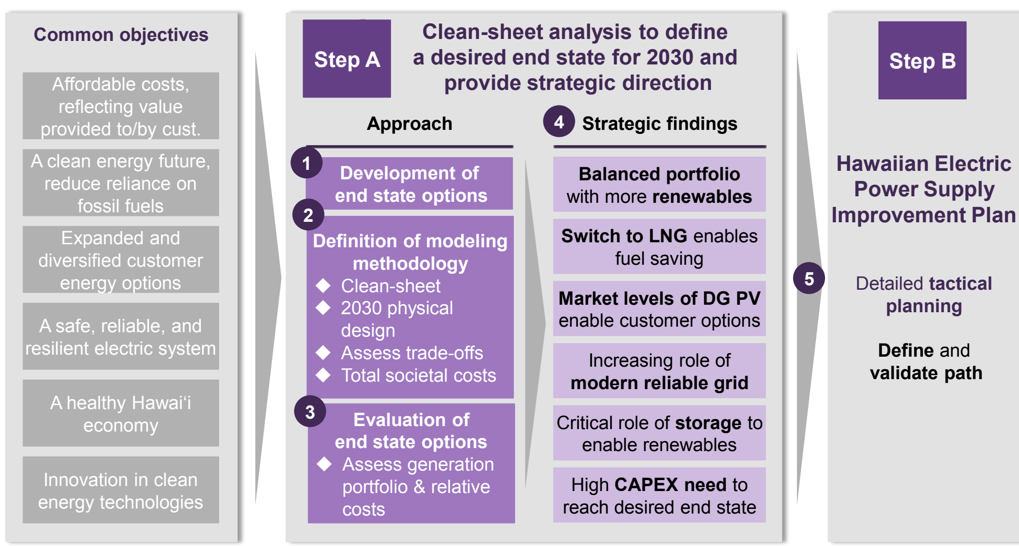

Figure 2-1. Approach to Define Desired Physical System Design 2030 End-State

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

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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—Oʻahu, Maui, Molokaʻi, Lanaʻi, and Hawaiʻi Island—with three utilities and five grids. This accounts for about 90% of all the generation requirements for the entire state of Hawaiʻi.

Maui Electric serves 69,000 customers combined on Maui, Molokaʻi, and Lanaʻi with 262 MW (net) generation on Maui, 12 MW (gross) generation on Molokaʻi, and 10.4 MW (gross) generation on Lanaʻi.

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.

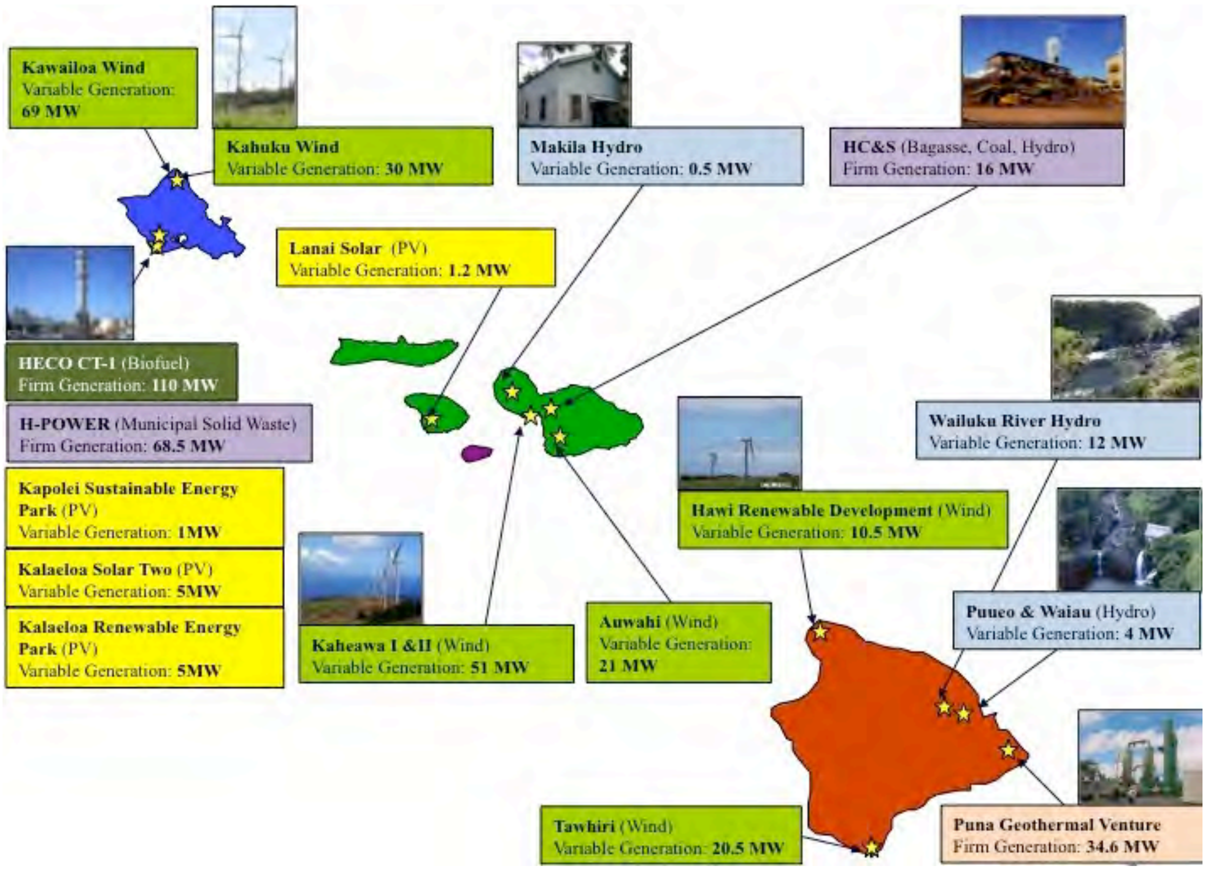

Figure 3-1. Current Clean Energy Resources

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%.

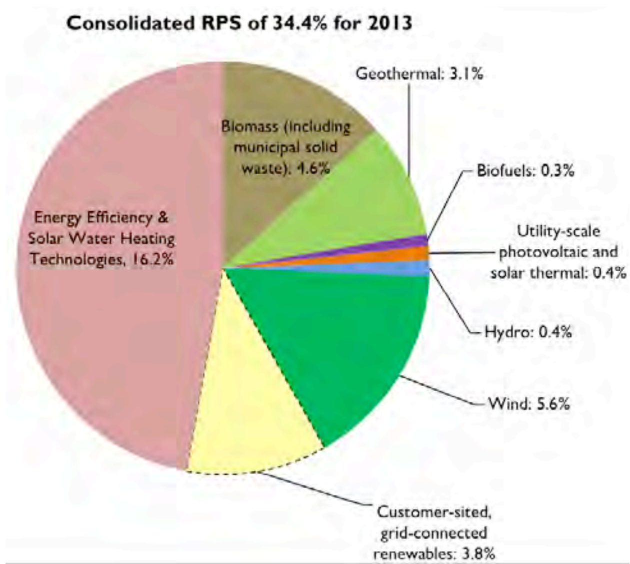

Figure 3-2. Consolidated RPS of 34.4% for 2013

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).

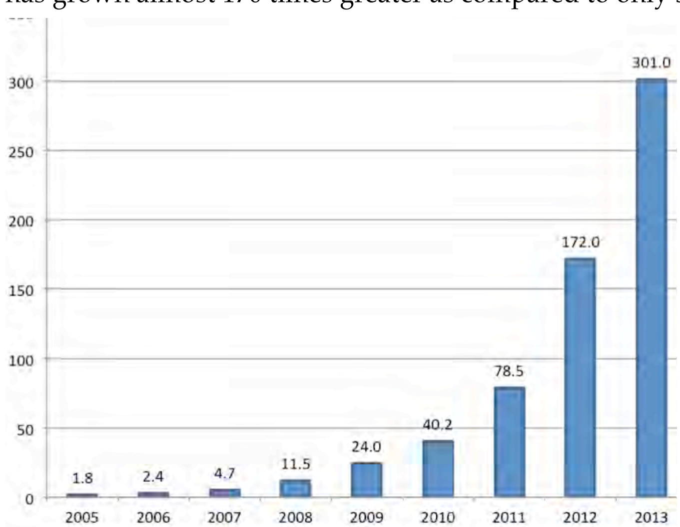

Figure 3-3. Photovoltaic Generation Growth: 2005 through 2013

MAUI ELECTRIC GENERATION

Maui Electric Generation Mix

Maui Electric Company owns and operates three island electric grids on the islands of Maui, Moloka‘i, and Lana‘i. Each island has its own unique physical grid design based on system load, demand, and customer needs.

Maui Electric generates the majority of its power from combined cycle and internal combustion engine units, as well as a growing portfolio of renewable energy. Maui’s total firm capacity is 262.28 MW (net). Lana‘i’s total firm capacity is 10.40 MW (gross). Moloka‘i’s total firm capacity is 12.01 MW (gross).

Maui Electric’s generation portfolio is composed of a mix of renewable and firm resources. Our current generation mix allows us to integrate significant amounts of renewable energy when available, while ensuring reliability for our customers.

Maui Island Grid

The Maui grid includes a growing portfolio of variable renewable energy that includes wind, solar photovoltaic, and hydropower. Our firm generation resources include centralized generating stations comprised of combined cycle and internal combustion engine units, oil-fired steam units, and biomass.

Energy delivery on the Maui System from the generation stations is through a 69 kV transmission and 23 kV sub-transmission lines. Maui has 65 distribution substations, situated near large customer load centers (towns, industrial centers, subdivisions) to allow power to be extracted from the transmission network and lowered to voltages that can be safely and efficiently distributed to customers.

Maui Utility-Owned Generation

Maui Electric owns and operates two generating stations and one distributed generation site on Maui.

Our Kahului Power Plant has four steam units totaling 35.92 MW (net)of firm capacity. Two of the four units were deactivated in accordance with our Curtailment Reduction Plan, but can be reactivated in the event of a shortfall.

Our Hana Substation No. 41 has two diesel units totaling 1.94 MW (net) of firm capacity.

Our Ma'alaea Power Plant has 15 diesel units, a combined cycle gas turbine, and two combined/simple cycle gas turbines totaling 208.42 MW (net) of firm capacity.

Hawaiian Commercial & Sugar is an independent power producer that uses a mix of biomass, coal, and hydroelectric resources to provide firm and supplemental generation to the Maui system.

Unit	Fuel	Type	Net-Reserve MW	Net-Normal Top Load MW
Kahului				
K1	Fuel Oil #6	Steam	5.62	4.71
K2	Fuel Oil #6	Steam	5.77	4.76
K3	Fuel Oil #6	Steam	12.15	10.98
K4	Fuel Oil #6	Steam	12.38	11.88
Total KPP			*35.92*	*32.33*
Hana				
H1	Diesel	Diesel	0.97	0.97
H2	Diesel	Diesel	0.97	0.97
Ma'alaea				
M1	Diesel	Diesel	2.50	2.50
M2	Diesel	Diesel	2.50	2.50
M3	Diesel	Diesel	2.50	2.50
M4	Diesel	Diesel	5.51	5.51
M5	Diesel	Diesel	5.51	5.51
M6	Diesel	Diesel	5.51	5.51
M7	Diesel	Diesel	5.51	5.51
M8	Diesel	Diesel	5.48	5.48
M9	Diesel	Diesel	5.48	5.48
M10	Diesel	Diesel	12.34	12.34
M11	Diesel	Diesel	12.34	12.34
M12	Diesel	Diesel	12.34	12.34
M13	Diesel	Diesel	12.34	12.34
M14, M15, M16	Diesel	Combined Cycle Gas Turbine	56.78	56.78
M17, M18, M19	Diesel	Two Combined/Simple Cycle Gas Turbines	56.78	56.78
X1	Diesel	Diesel	2.50	2.50
X2	Diesel	Diesel	2.50	2.50
Total MPP			208.42	208.42
Total Utility Owned	—	—	*246.28*	*242.69*

Table 3-2. Maui Utility-Owned Generation Units

Lanaʻi Utility-Owned Generation

The Lanaʻi grid includes a centralized generating station with nine (9) diesel units with 10.4 MW of capacity. In addition the La Ola photovoltaic farm, owned by Lanaʻi Sustainability Research, contributes 1.2 MW.

Miki Basin Units LL-l to LL-6 (six 1,000 kW diesel engine-generator units totaling 6,000 kW) were converted to peaking status at the end of 2006, and as such, can be relied on for 5,000 kW of capacity to the Lanaʻi system. Lanaʻi's distribution system is operated at 12.47 kV, 6.6 kV, and 2.4 kV. Lanaʻi does not currently have any transmission lines in place.

Unit	Fuel	Type	Gross-Reserve MW	Gross-Normal Top Load MW
LL1	Diesel	Peaking	1.00	1.00
LL2	Diesel	Peaking	1.00	1.00
LL3	Diesel	Peaking	1.00	1.00
LL4	Diesel	Peaking	1.00	1.00
LL5	Diesel	Peaking	1.00	1.00
LL6	Diesel	Peaking	1.00	1.00
LL7	Diesel	Firm Capacity	2.20	2.20
LL8	Diesel	Firm Capacity	2.20	2.20
Manele Bay CHP	Diesel	Firm Capacity	1.00	0.83
Total	—	—	*10.40*	*10.23*

Table 3-3. Lanaʻi Utility-Owned Generation Units

Molokaʻi Utility-Owned Generation

Molokaʻi has capacity to generate 12.0 MW (gross) of power at the Palaʻau Power Plant.

The Molokaʻi grid includes a centralized generating station with nine (9) diesel internal combustion units and one (1) diesel combustion turbine. It includes an overhead transmission line from Palaʻau Generation Plant to Puʻunana Substation. Molokaʻi's transmission and distribution systems are operated at 34.5 kV, 12.47 kV, 4.16 kV, and 2.4 kV respectively.

Unit	Fuel	Type	Gross-Reserve MW	Gross-Normal Top Load MW
Palaʻau #7	Diesel	Firm Capacity	2.2	2.20
Palaʻau #8	Diesel	Firm Capacity	2.2	2.20
Palaʻau #9	Diesel	Firm Capacity	2.2	2.20
Palaʻau #10	Diesel	Firm Capacity	2.2	2.20
Palaʻau #1	Diesel	Peaking	1.25	1.25
Palaʻau #2	Diesel	Peaking	1.25	1.25
Palaʻau #3	Diesel	Peaking	0.97	0.97
Palaʻau #4	Diesel	Peaking	0.97	0.97
Palaʻau #5	Diesel	Peaking	0.97	0.97
Palaʻau #6	Diesel	Peaking	0.97	0.97
Total	—	—	*12.01*	*12.01*

Table 3-4. Molokaʻi Existing Generation Units

Palaʻau units 1 and 2 (two 1,250 kW Caterpillar units), and Palaʻau Units 3, 4, 5, and 6 (four 970 kW Cummins units) operate in peaking service. Because of the age and operating history of these units, Maui Electric includes one Caterpillar unit and two Cummins units (1,250 + 970 + 970 = 3,190 kW) toward firm capacity for the Molokaʻi system.

Maui Electric Renewable Generation

Compared to a 15.3% RPS attainment in 2010, Maui Electric has almost doubled the amount of renewable energy on the system to 29.1% in 2013.

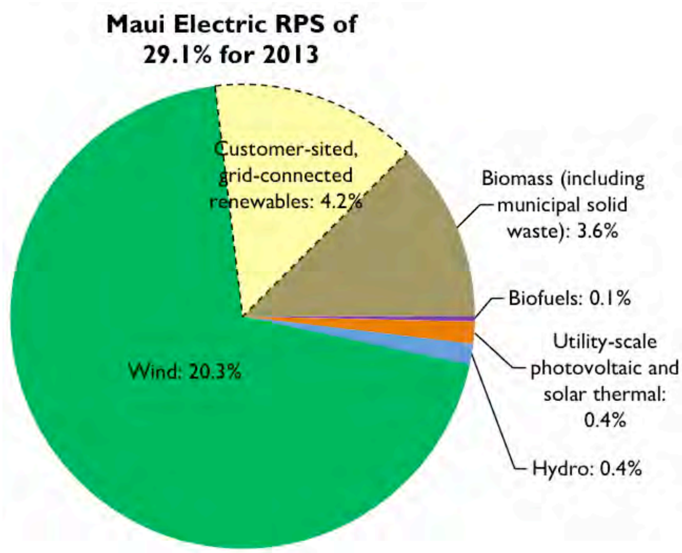

Figure 3-4. 2013 Maui Electric RPS Percent

Variable Resources

As of December 31, 2013, there was also 126.6 MW of capacity from renewable sources on Maui, Lana‘i, and Moloka‘i.

Maui Electric's system incorporates wind energy from three wind farms totaling 72 MW of variable renewable generation on Maui island via power purchase agreements. Kaheawa I consists of 20 wind turbines that provide us with 30 MW of variable capacity. Kaheawa II consists of 14 wind turbines that provide us with 21 MW of variable capacity. Auwahi consists of 8 wind turbines that provide us with 21 MW of variable capacity.

Makila hydroelectric unit provides Maui Electric with 0.5 MW of variable capacity.

Unit	Energy	Rating MW	Type
Hawaiian Commercial & Sugar (Maui)	Bagasse, Coal, Hydro	12.0 4.0	Firm Supplemental
Kaheawa I (Maui)	Wind	30.0	Variable
Kaheawa II (Maui)	Wind	21.0	Variable
Makila Hydro (Maui)	Hydro	0.5	Variable
Auwahi (Maui)	Wind	21.0	Variable
La Ola Solar (Lana‘i)	Solar PV	1.2	Variable
NEM and FIT (Maui, Lana‘i, Moloka‘i)	Mostly Solar PV	41.7	Variable
Total	—	*131.4*	—

Table 3-5. Renewable Generation on Maui, Lana‘i, and Moloka‘i (December 31, 2013)

MAUI ELECTRIC 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.

Maui Distributed Generation

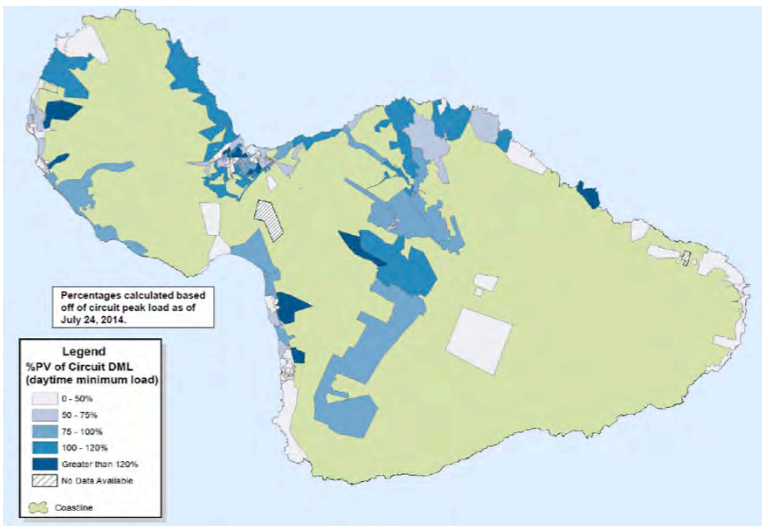

Figure 3-5. Maui Distributed Generation Map

Lana'i Distributed Generation

Figure 3-6. Lana'i Distributed Generation Map

Moloka'i Distributed Generation

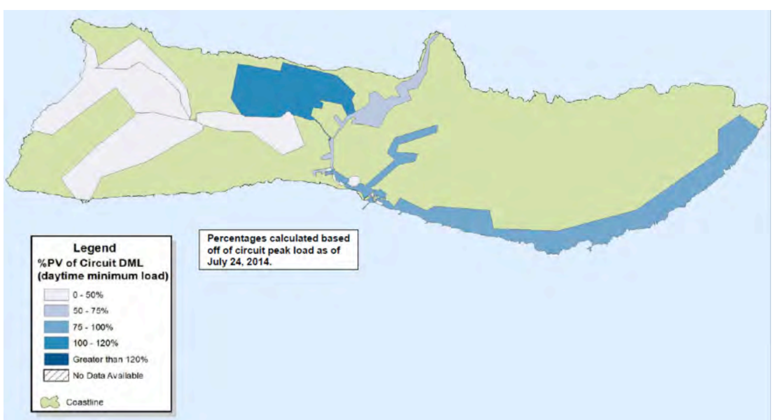

Figure 3-7. Moloka'i Distributed Generation Map

O'AHU–MAUI GRID INTERCONNECTION

For several years, the idea of inter-island cables between O'ahu and the neighbor islands have been discussed. An interisland cable would involve developing a High Voltage Direct Current (HVDC) submarine cable interconnection between islands. Submarine HVDC systems utilize a mature technology with very high service reliability. There are many such systems in operation around the world.

There are two fundamental purposes for such interconnections:

- Increase renewable energy penetration for O'ahu: One of the state of Hawai'i's major goals is to increase renewable generation. The majority of the state's population, and thus the majority of the Hawaiian Electric Companies' system load, is on O'ahu. Conversely, much of the best renewable resource potential is on the neighbor islands, particularly Maui County and Hawai'i Island.
- Increase the overall operating efficiencies of the O'ahu and Maui power systems: It may be possible to improve the efficiencies of the O'ahu and Maui systems by jointly dispatching the two systems utilizing an interconnection.

The use of a submarine cable to interconnect remote renewable generators to O'ahu makes sense only if sufficient renewable resources cannot be sourced on O'ahu. In the preferred plan, it appears that the 40% RPS goal by 2030 can be met with a combination of additional wind, utility-scale solar and biofuels, without the need to import renewable generation from other islands. Therefore, for purposes of this PSIP, the Companies have not considered HVDC submarine cables to access additional renewable resources. If in the future, this key planning assumption proves to be incorrect, an inter-island cable could become feasible for this purpose. This planning assumption does not preclude proposals for neighbor island-sited renewable generation to serve O'ahu through a submarine cable, provided that such proposals are cost effective and reliable, relative to other options available to Hawaiian Electric.

With respect to the benefits of using interisland cables to achieve joint dispatch benefits between the Hawaiian Electric and Maui Electric systems, the PSIP analyses did include an evaluation of an interconnection between O'ahu and Maui.

O'ahu–Maui Interconnection Specifications

The assumed O'ahu–Maui interconnection configuration for purposes of the PSIP's is two (HVDC) cables, each with a load carrying capacity of 100 MW. The 100 MW maximum size for each circuit was assumed in order to keep the single largest generating contingency at 100 MW, or roughly the same size as the largest unit in the O'ahu system. The cable is assumed to be bi-directional: power can flow in either direction. Such a cable system would consist of:

- Two submarine HVDC cables installed between O'ahu and Maui, with separate landfall and interconnection points on either end of the cable.
- Four 100 MW each AC/DC converter stations (one for each end of each HVDC circuit); and AC interconnection facilities and system upgrades as necessary in the Hawaiian Electric and Maui Electric systems to interconnect the HVDC interisland cable system.
- All overheads necessary to site, permit, design, construct and operate the HVDC interisland cable system.

Interisland Cable Feasibility Analysis Approach

The feasibility of utilizing an interisland cable for joint dispatch of the Hawaiian Electric and Maui Electric systems was evaluated by comparing:

- The net present value of system production costs with the Hawaiian Electric and Maui Electric systems assumed to be interconnected in a manner that allows economic dispatch of generation on both islands; to
- The sum of the present value of system production costs for each of the Hawaiian Electric and Maui Electric systems.

The difference between these two cases provides the gross benefit that could be provided by an interisland cable system that enables joint dispatch. This represents the higher bound of what an interisland cable could cost and still be economically feasible. This value was then compared to known cost estimates for an O'ahu–Maui interisland HVDC cable system[13].

Using this methodology, it is not necessary to estimate the cost of this particular cable configuration. Instead, the differential computed above can be compared to known cost estimated for this proposed project. If the benefits are substantially less that the lowest interisland cable cost estimate known to date, then a cable is not economically feasible at this time. If on the other hand, the difference approaches the known cost estimate levels, then further analysis must be performed. This is a conservative approach since the existing cost estimates are for a single 200 MW HVDC system; a system with two 100 MW HVDC circuits is likely to be substantially more expensive (and complicated in terms of permitting) given the need for two routes, and two cable installations.

[13] The lowest know cost estimate for an interconnection between the Maui and O'ahu systems is $600,000,000, provided by NextEra Energy Hawai'i LLC on September 9, 2013 in Docket No. 2013-0169.

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 Hawai‘i 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). Hawai‘i is a pioneer in OTEC research, having demonstrated the first successful OTEC project on Hawai‘i Island in the 1970s. Despite the technological promise of OTEC for large-scale electricity generation, no full-scale OTEC plant has yet to be built anywhere in the world. Hawaiian Electric is currently in power purchase negotiations with OTEC International (OTECI) for an OTEC facility to provide power to the island of O‘ahu. 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 Hawai‘i. We currently partner with the U.S. Navy (and others) in a small scale pilot. Small utility-scale wave power projects have been installed in Europe. Implementing large-scale tidal and wave installations has thus far been hampered by a lack of understanding of the associated siting and permitting 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. 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.

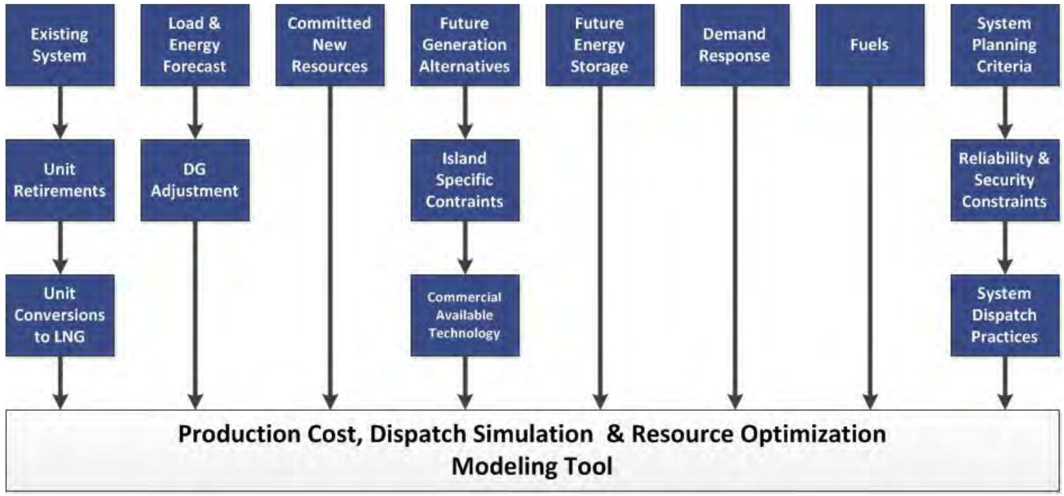

Figure 4-1. PSIP Production Simulation Model Input Hierarchy

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 Moloka'i 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 Moloka'i, 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.

Hawai'i Electric Light: As of the end of 2013, the existing Hawai'i Electric Light power system on Hawai'i 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. Hawai'i 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
Hawai'i 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 Hawai'i 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.

Hawai'i 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*.[14]

[14] 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.

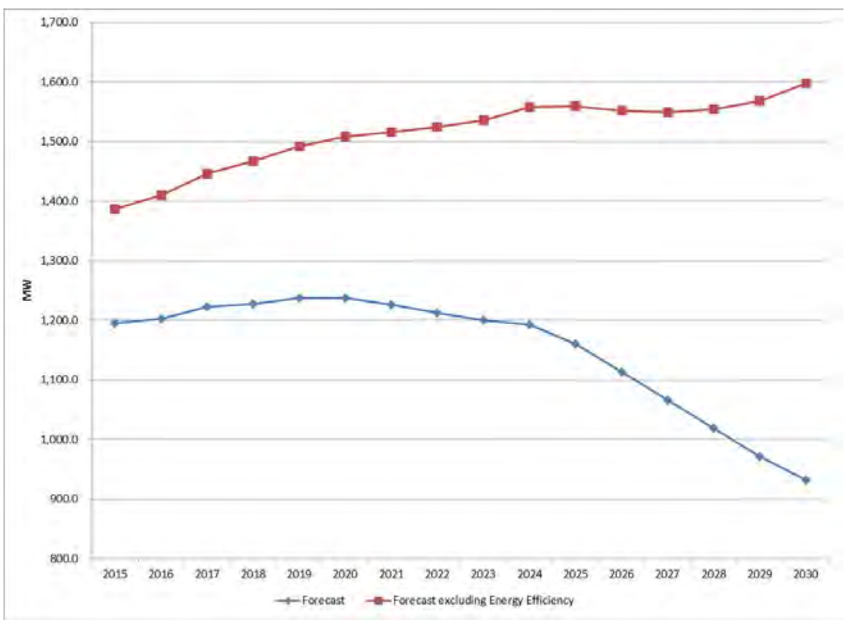

Figure 4-2. Hawaiian Electric Peak Demand Forecast (Generation Level)

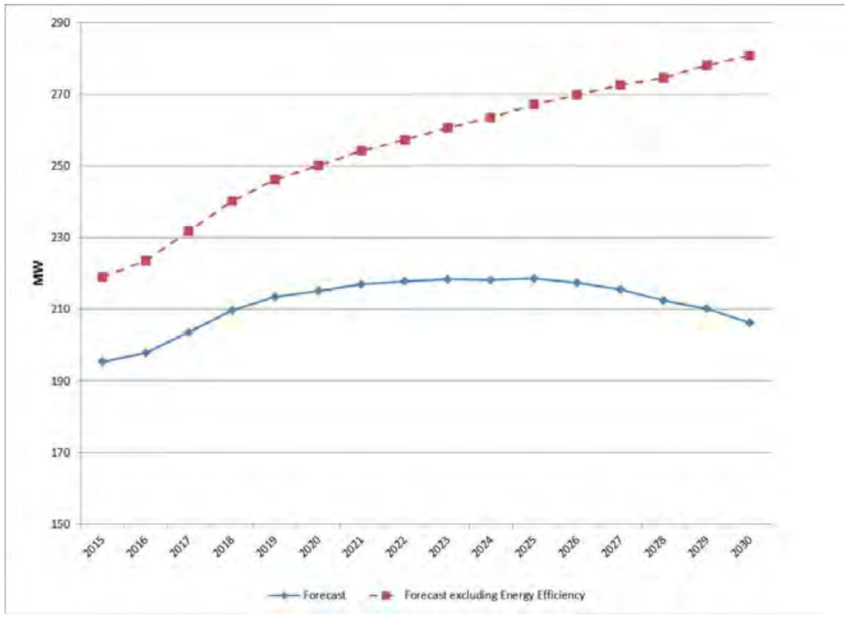

Figure 4-3. Maui Peak Demand Forecast (Generation Level)

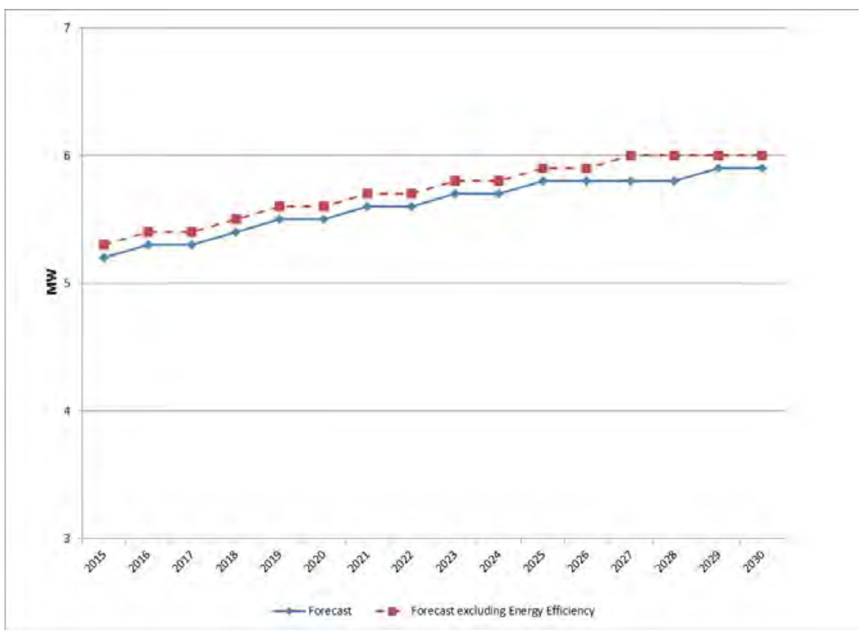

Figure 4-4. Lana‘i Peak Demand Forecast (Generation Level)

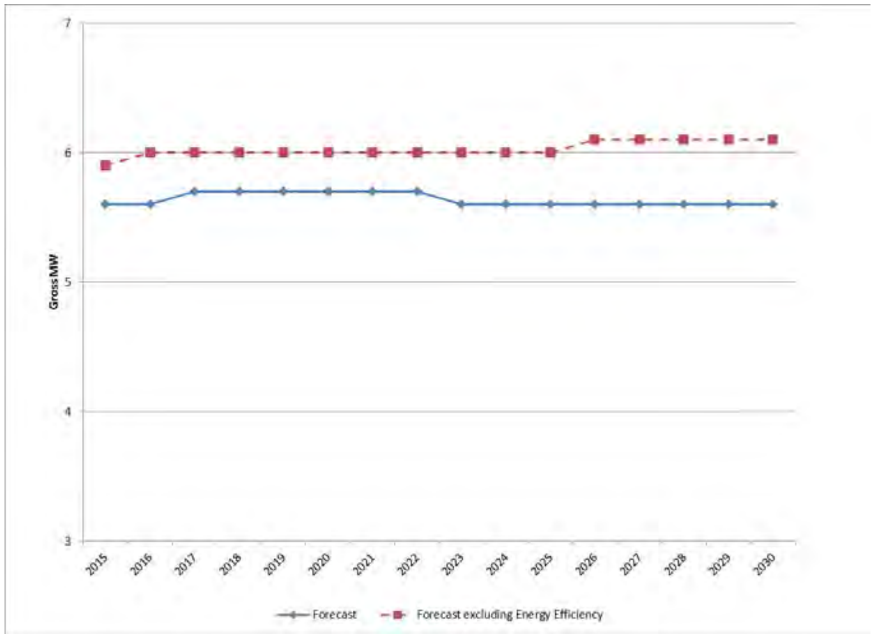

Figure 4-5. Moloka‘i Peak Demand Forecast (Generation Level)

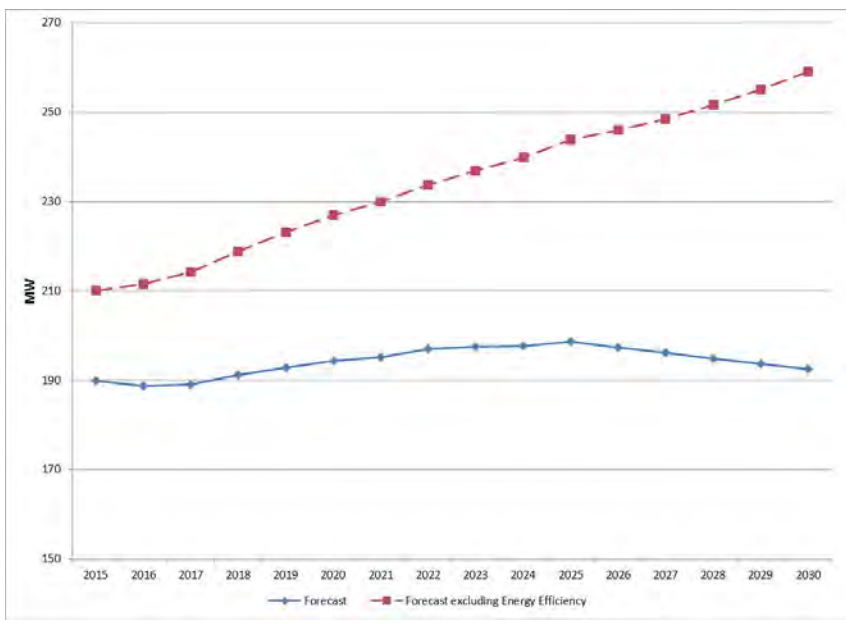

Figure 4-6. Hawai‘i Electric Light Peak Demand Forecast (Generation Level)

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.

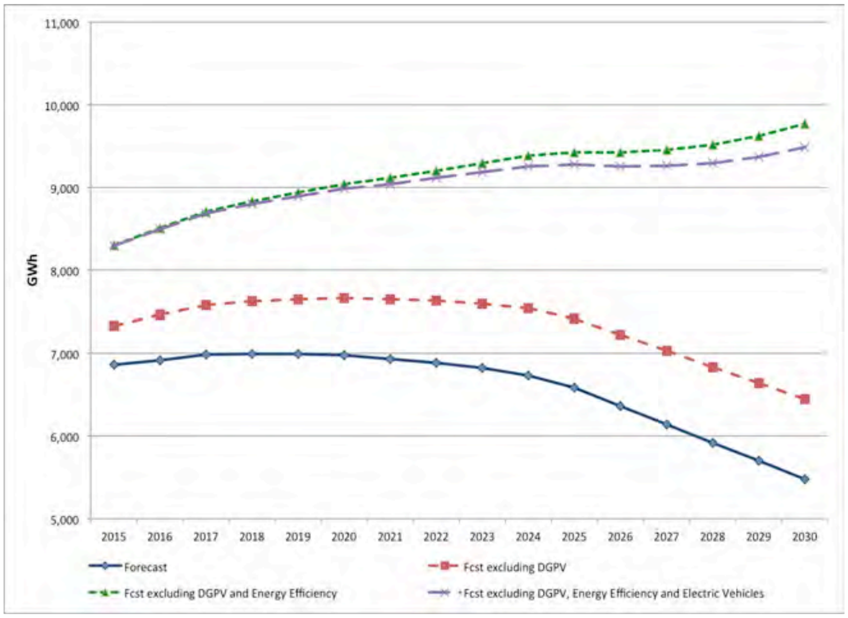

Figure 4-7. Hawaiian Electric Energy Sales Forecast (Customer Level)

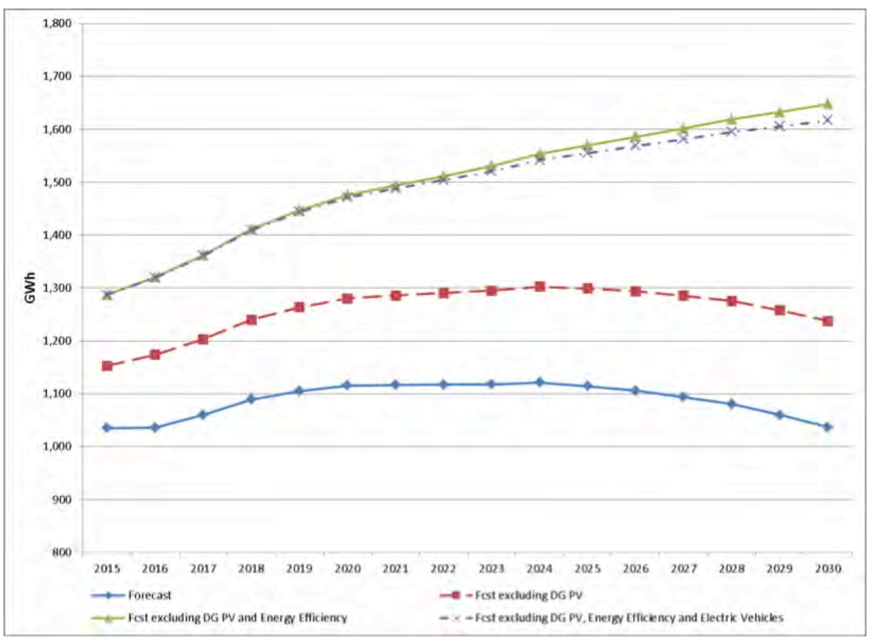

Figure 4-8. Maui Energy Sales Forecast (Customer Level)

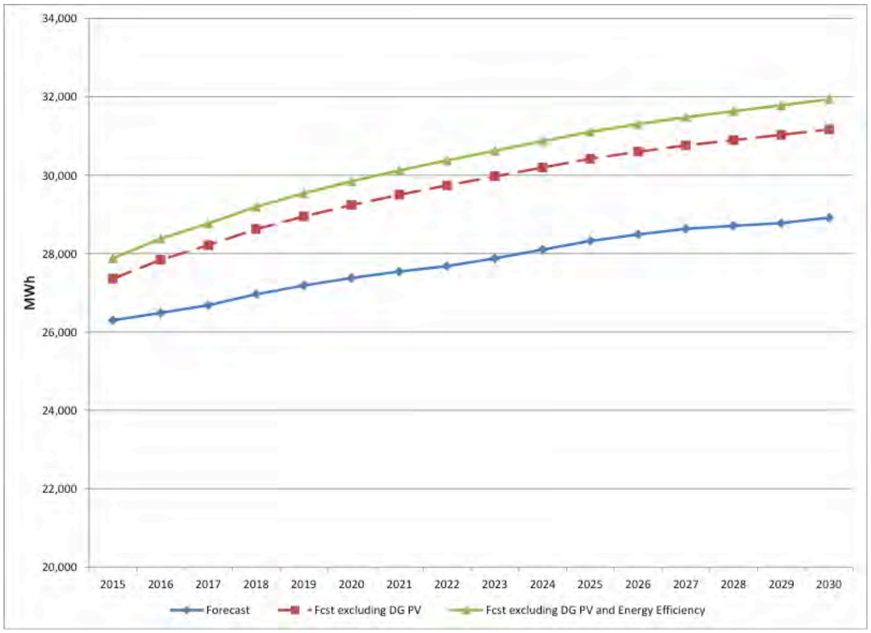

Figure 4-9. Lana'i Energy Sales Forecast (Customer Level)

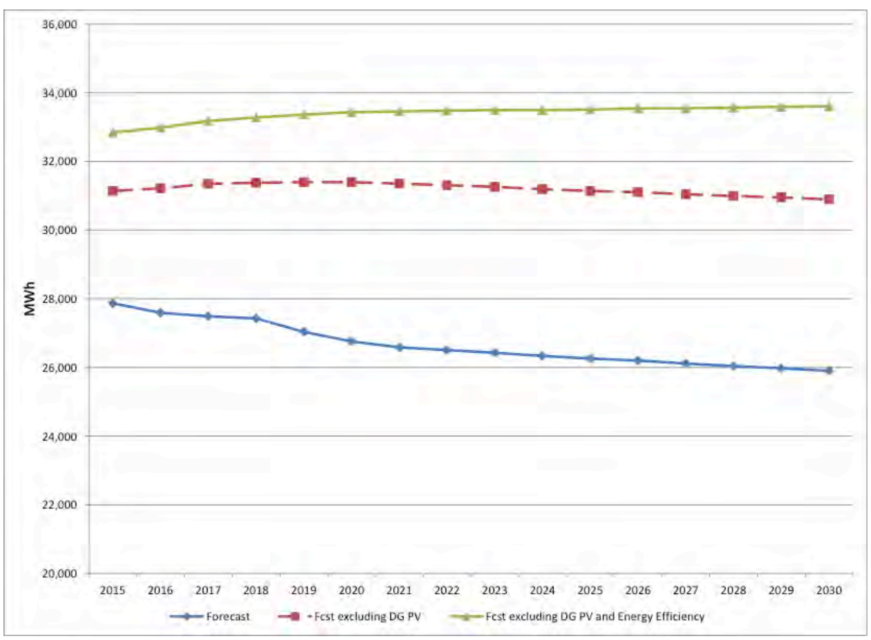

Figure 4-10. Moloka'i Energy Sales Forecast (Customer Level)

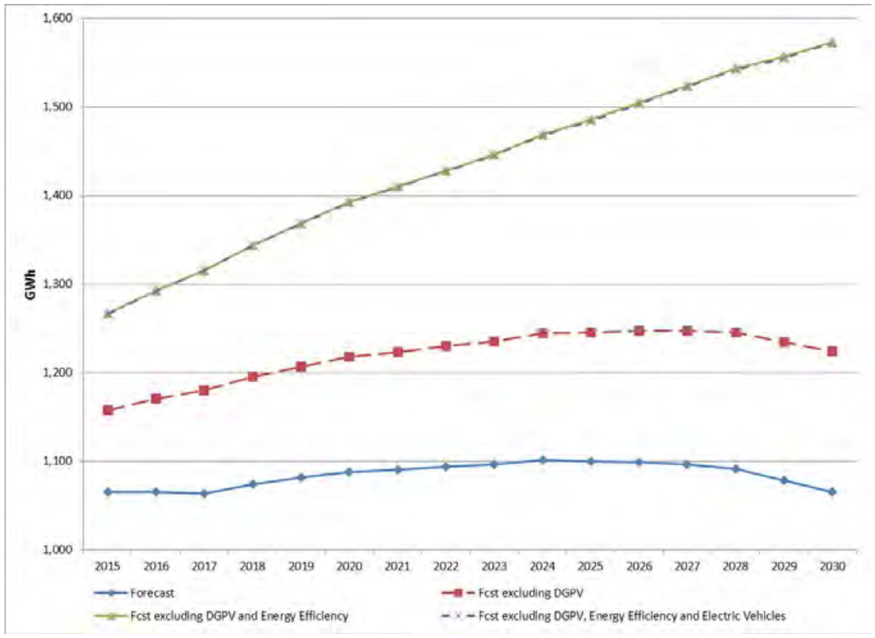

Figure 4-11. Hawai'i Electric Light Energy Sales Forecast (Customer Level)

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.

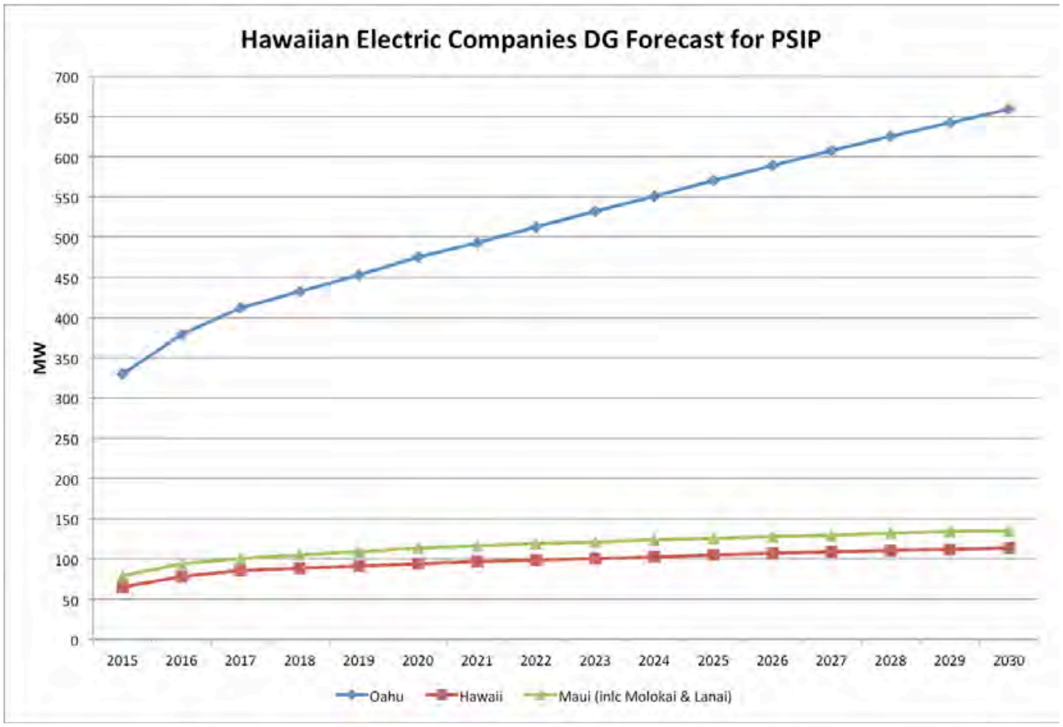

Figure 4-12. Installed DG Forecasts

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[15]. 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.

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[15] 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

Hawaiʻi 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 23 kV 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[16]. 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.

[16] 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	
23 kV System	23 kV Waiinu-Kanaha upgrade to 69 kV and re-conductoring of MPP–Waiinu and MPP–Pu‘unene from 336AAC to 556AAC	
Under voltage and voltage stability	South Maui	Kamalii Substation and MPP–Kamali‘i 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.

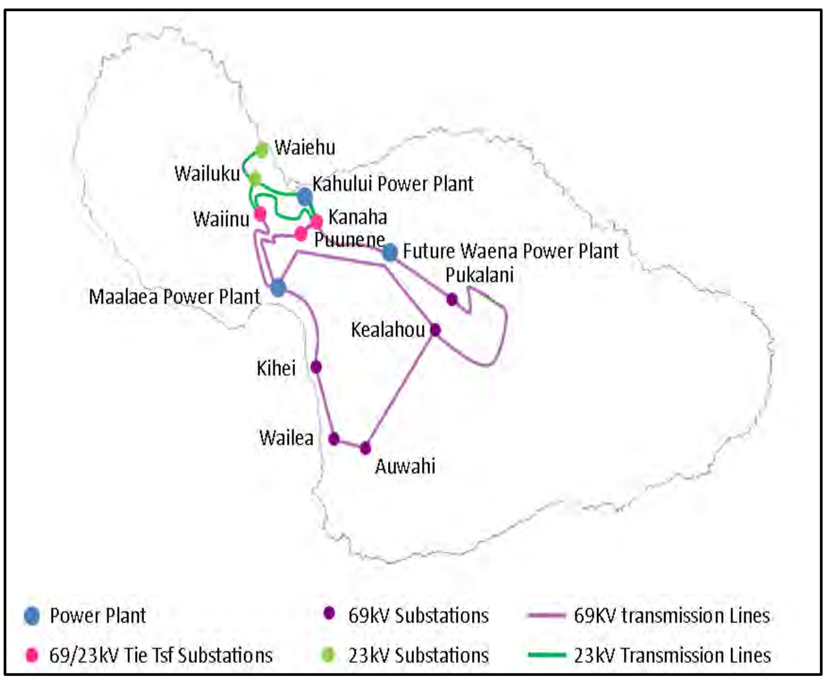

Figure 4-13. Transmission Overview for Key Maui Electric Substations Related to NTAs

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[17]. Additionally, DG-PV provides little to no generation during system peak periods[18], 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

[17] 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.

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

these feeders[19] 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 69 kV 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-Wai‘inu 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[20]. 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[21] and possibility of a voltage collapse. The distance would increase to approximately 23 miles, as shown in Figure 4-14.

[19] MPP-Waiinu or MPP-Pu‘unene.

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

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

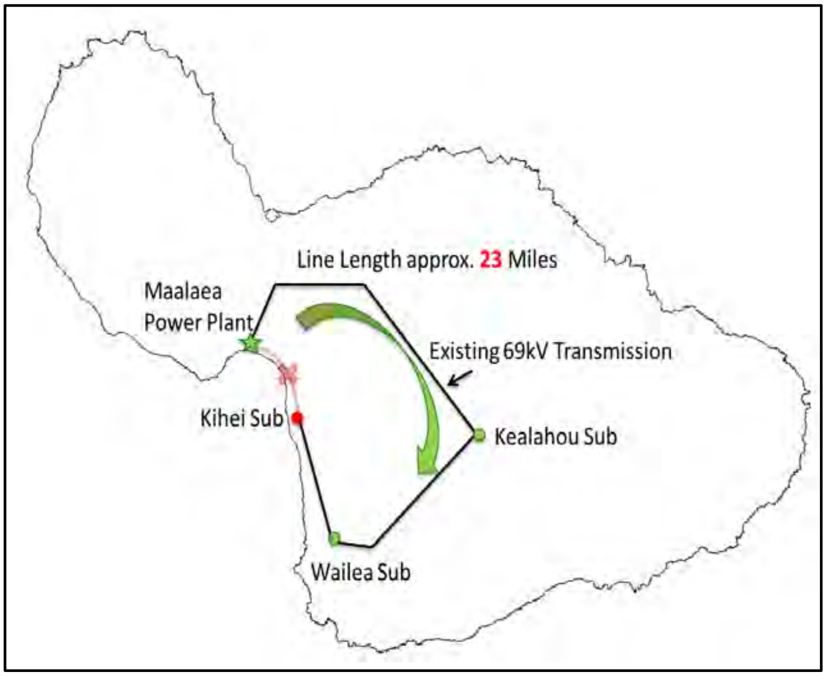

Figure 4-14. Longer Distance Required to Serve Loads in Kihei Under an N-1 Contingency

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.[22] 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

[22] 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 30 minutes. 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[23] 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[24] 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

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

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

"security" became synonymous with homeland protection in general, and critical infrastructure protection in particular[25].

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[26], 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

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

[26] 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[27], 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

[27] 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.

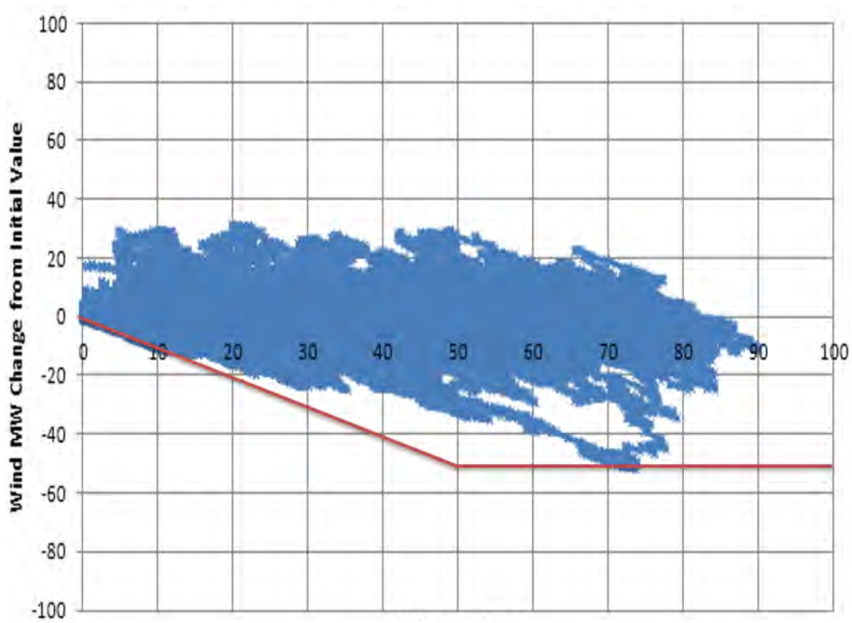

Figure 4-15. 20-Minute Scatter Plot for Hawaiian Electric Wind Generation

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.

Hawaiʻi Electric Light Wind Generation: The wind ramps on the Hawaiʻi 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 Hawaiʻi Electric Light system for the first half of May 2014 for the Hawaiʻi Renewable Development (HRD) and Tawhiri wind generation facilities.

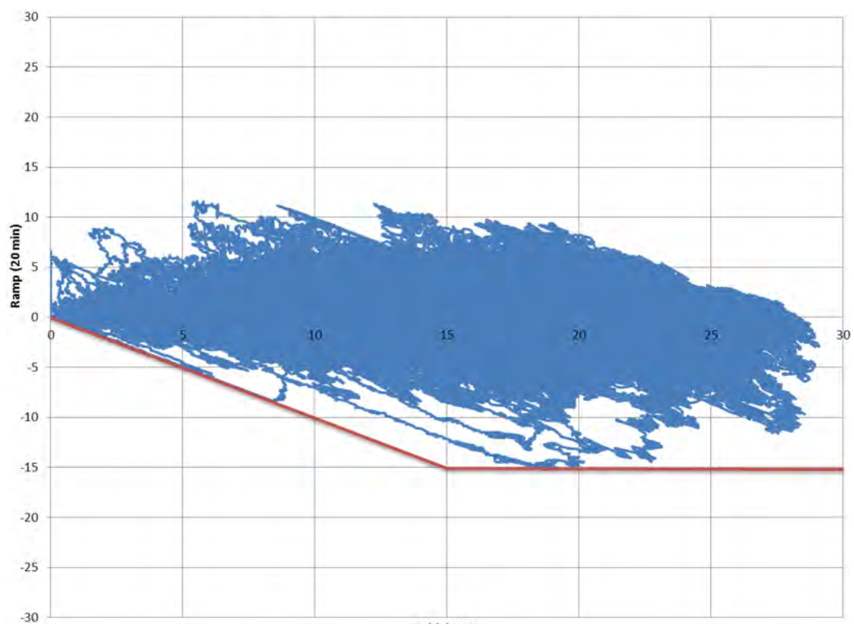

Figure 4-16. 20-Minute Scatter Plot for Hawaiʻi Electric Light Wind Generation

Maui Electric Wind Generation: The wind ramps on the Maui Electric system require less regulating reserve compared to those for the Hawaiʻi 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.

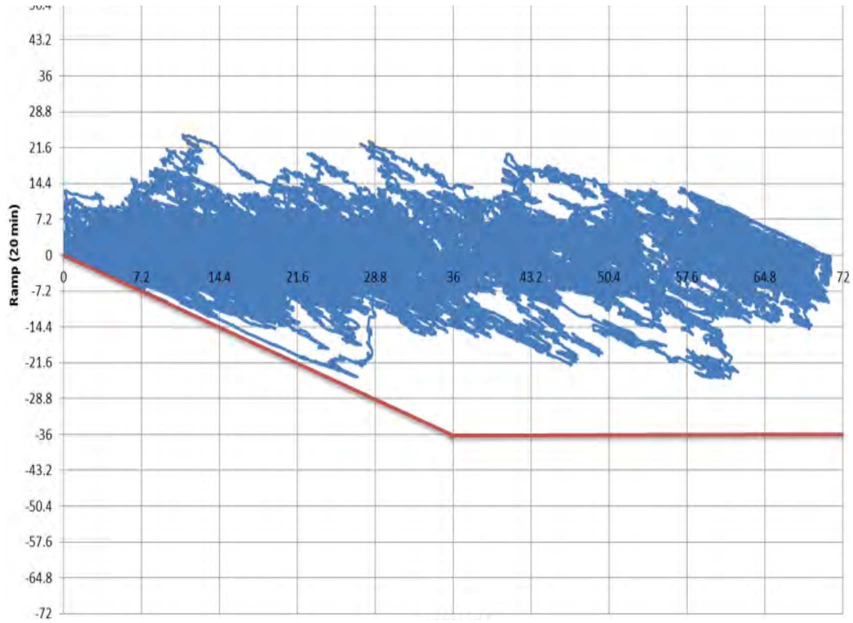

Figure 4-17. 20-Minute Scatter Plot for Maui Electric Wind Generation

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

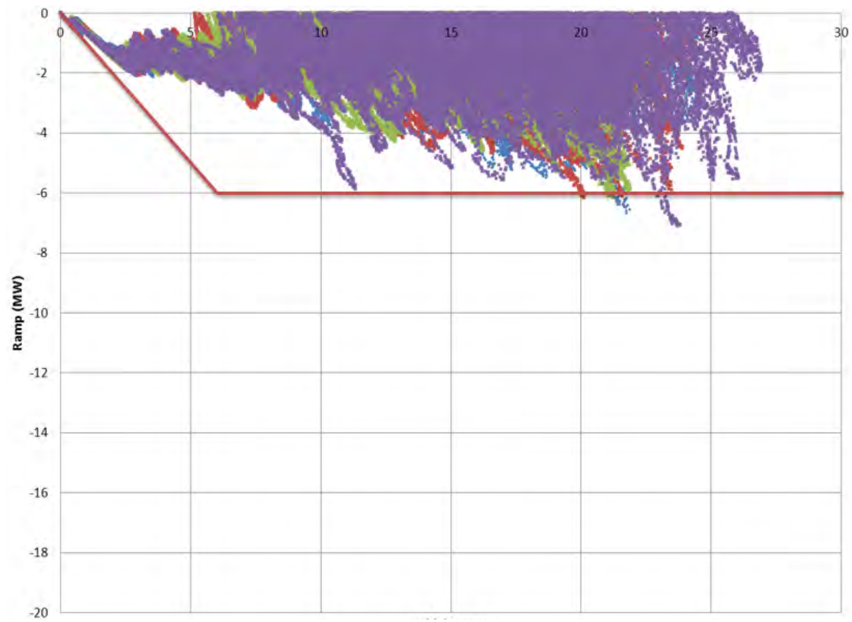

Figure 4-18. Maui Electric 20-Minute Solar Ramps

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).

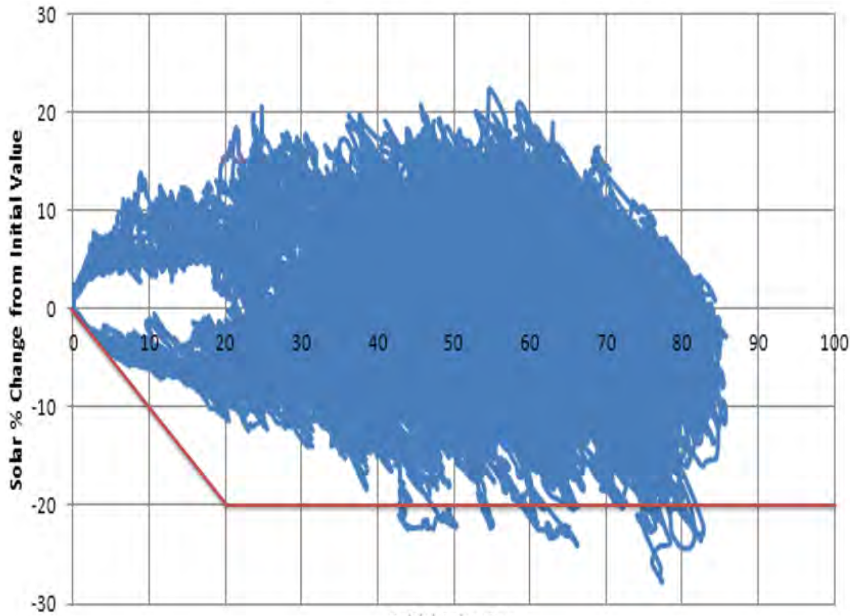

Figure 4-19. Hawai'i Electric Light 20-Minute Solar Ramps for Half of February

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.

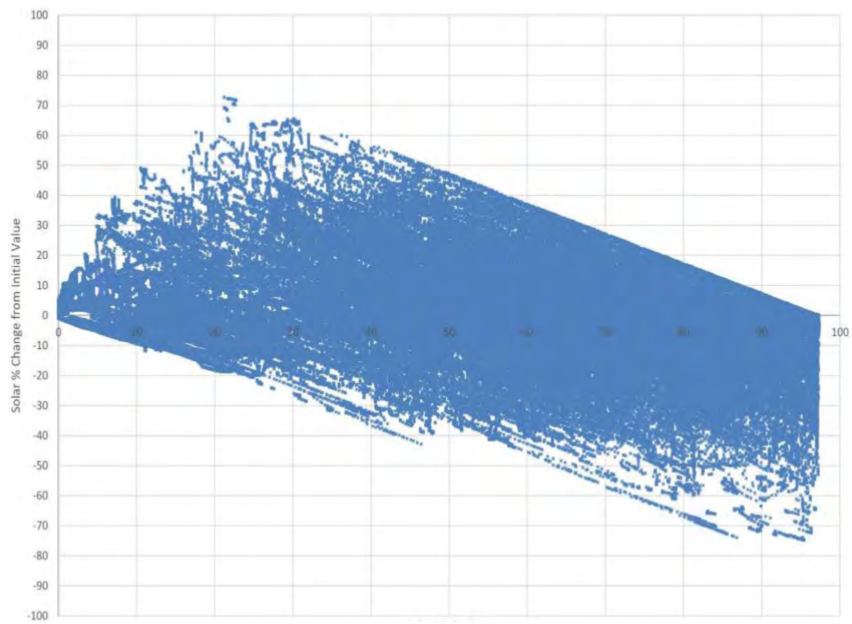

Figure 4-20. Hawaiian Electric Combined Station Class PV

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.[28] 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

[28] 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).

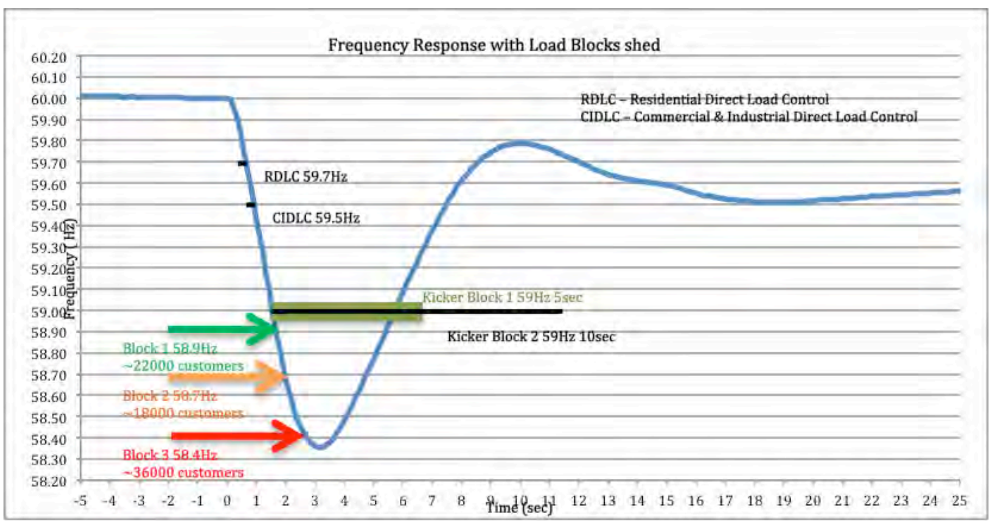

Figure 4-21. Frequency Response with Load Blocks Shed

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 + LMS1000 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. Hawai‘i 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

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

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

The Preferred Plan for the island of Maui reduces "must-run" generation, increases variable renewable energy, and uses firm renewable sources to help stabilize the grid. Existing fossil-fuel steam generating units will be replaced with more flexible, fast-starting, peaking and/or cycling thermal generating units, and renewable firm baseload generation is scheduled to replace existing diesel generating units. Demand response will also be used to further reduce fossil fuel utilization. The Preferred Plans for Lana‘i and Moloka‘i increase variable renewable energy, and switch to using lower costs fuels in our generators.

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

MAUI ELECTRIC OF 2030: A VISION OF OUR PLAN

Our vision will advance our systems toward our goal of decreasing fossil fuels, integrating more renewable energy, and reducing customers' bills while maintaining system reliability. Our commitment to reshape our systems will result in a Renewable Portfolio Standard (RPS) of approximately 72%, substantially exceeding the requirement of 40% by 2030.

The Preferred Plans outline the transformation that we will undertake to evolve into a utility of the future—meeting the current and future needs of the community and customers we serve.

Maintaining flexibility in the resource options positions us to provide the lowest cost alternatives, while increasing renewable energy and ensuring reliability. As we execute the Maui Preferred Plan we will incorporate more firm renewable resources, such as geothermal, biomass, and more variable renewable resources, such as wind and solar PV. We will take advantage of PV technology that can produce larger, centralized projects that can benefit the entire community, and also distributed generation (DG-PV) projects that are sited at customers' residential and business premises.

Our plan also includes a non-transmission alternative for the South Maui area. Firm generation is planned for South Maui to support the electrical system instead of new overhead transmission infrastructure. Initially, the firm generation will be comprised of internal combustion engines, which will later be replaced by geothermal, a renewable resource. The internal combustion engines will likely be relocated to Central Maui when the geothermal is commercialized.

Maui Preferred Plan

The timeline for the Maui Preferred Plan is presented in Figure 5- below, and it shows when new resources would be added (above the date line) and existing resources would be retired (below the date line).

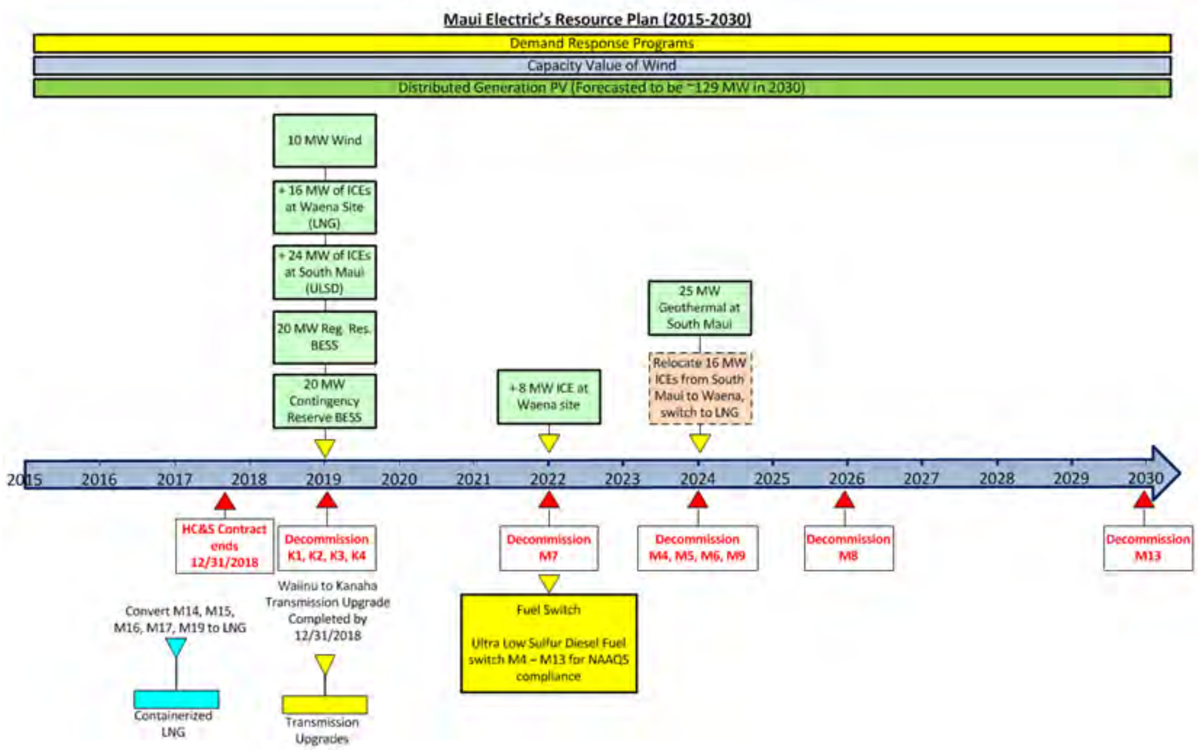

Figure 5-1. Timeline Diagram of Maui Electric: Maui Preferred Plan

The Preferred Plan allows us to increase renewable energy utilization by:

1. Retiring existing less flexible, less efficient generating units at the Kahului Power Plant.

2. Installing resources that can provide system stability:

   - Install contingency Energy Storage Systems (ESS) in combination with quick starting generation in South Maui as a non-transmission alternative.
   - Install LNG-fueled fast starting generation as needed in Waena to ensure sufficient capacity and to ensure that reserve margin criteria is maintained
   - Upgrade the Waiinu to Kanaha Transmission Line.
   - Implement Demand Response Programs.

3. Installing resources that reduce online reserves:

   - Install Regulating Reserve ESS to maintain system security after Kahului Power Plant is retired.

The Preferred Plan also controls costs to its customers by:

1. Implementing lower-cost energy resources:
   - Wind power
   - Geothermal in South Maui
   - Retire more expensive diesel units when no longer needed for capacity
   - Solar photovoltaic
2. Operating existing high efficiency and new quick-starting thermal generating units on LNG:
   - Install a LNG regasification facility at Waena.
   - Switch dual-train combined cycle units to LNG.
   - Operate new quick starting generation fueled by LNG at Waena.
   - Relocate quick starting generation replaced by geothermal in South Maui to Waena for LNG fueling.

Lana‘i and Moloka‘i Preferred Plans

We conducted analysis for the islands of Lana‘i and Moloka‘i to develop preferred plans that are described below. Neither Lana‘i nor Moloka‘i required additional firm generation capacity to reliably meet the forecasted peak demand. However, we analyzed 100% renewable options, 50% LNG options, and options to reduce cost for each island.[29] The Preferred Plans below are based on modeling results and could change in response to community acceptance, refinement of system analysis, and actual costs of additional resources.

Based on the analysis, the Preferred Plans for both Lana‘i and Moloka‘i islands are:

- 50% LNG fuel switch in 2017
- 50% biodiesel fuel switch should the cost decrease to below that of ULSD
- Utility-scale solar installed in 2018
- Large-scale energy storage installed in 2018

[29] There is significant uncertainty around activities of large developers that may impact future analysis. We found that more in-depth study would be required to refine the various resource capacity requirements, more accurately evaluate potential curtailment issues, and to assess the feasibility of operating the system given the various resources in each plan.

The timeline for the Lana'i and Moloka'i Preferred Plans are presented in Figure 5-2 and Figure 5-3 below.

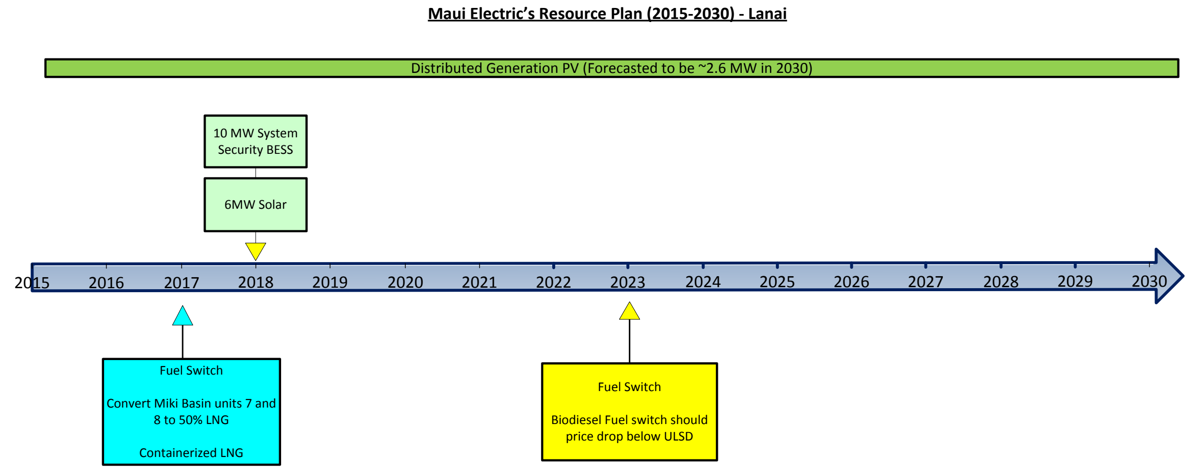

Figure 5-2. Timeline Diagram of Maui Electric: Lana'i Preferred Plan

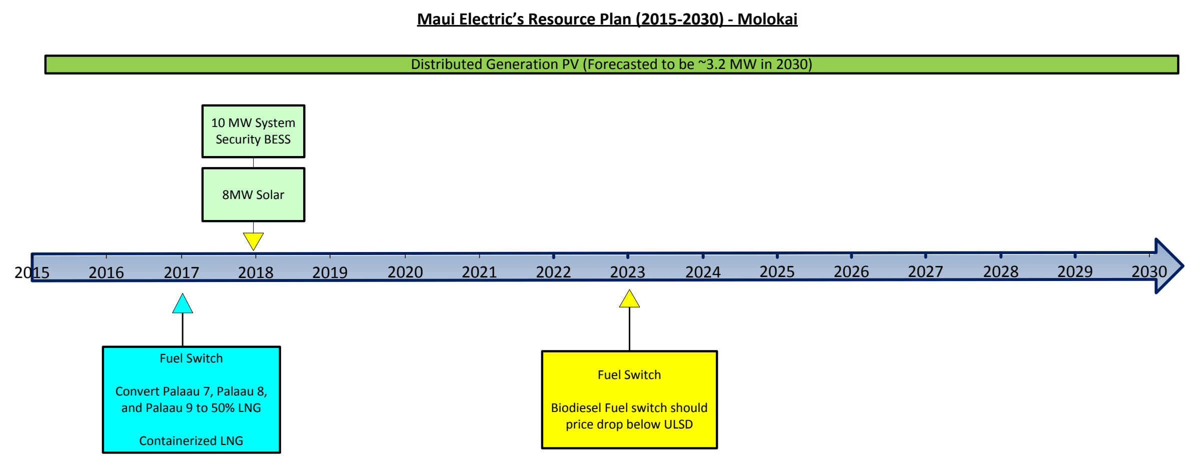

Figure 5-3. Timeline Diagram of Maui Electric: Moloka'i Preferred Plan

GENERATION RESOURCE CONFIGURATION

The transformation of the electric system design allows for substantial renewable energy integration. To accomplish this, the firm generation resource mix must evolve to ensure system reliability and stability.

Adequacy of Power

Our first priority is providing safe and reliable service to our customers. This starts with maintaining an adequate amount of capacity to meet our customers' needs.

Maui's Preferred Plan complies with current capacity planning criteria[30], as well as draft planning criteria, BAL-502, provided in Appendix M. The draft planning criteria in BAL-502 includes providing capacity value to demand response, grid-side variable renewable generation, and energy storage. For the purposes of the PSIP, a minimum of 30% reserve margin was targeted. Figure 5-1 shows the resulting reserve margin for the Preferred Plan.

Year	Peak (MW)	Total Thermal Capacity (MW)	New Thermal Generation (MW)	Retirements (MW)	DR for Capacity (MW)	Energy Storage for Capacity (MW)	Wind Capacity (MW)	Notes	Reserve Margin (%) Base	Reserve Margin (%) w/ DR	Reserve Margin (%) w/ Energy Storage	Reserve Margin (%) w/ Capacity Value of Wind
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	194	262	0	0	0	0	2.0		35.4%	35.6%	35.6%	36.6%
2015	195	250	4	(16)	1	0	2.0	HC&S Capacity Reduced to 4MW 1/1/2015	28.1%	28.7%	28.7%	29.7%
2016	197	250	0	0	5	0	2.0		26.9%	30.2%	30.2%	31.3%
2017	192	250	0	0	6	0	2.0		30.5%	34.8%	34.8%	35.8%
2018	197	250	0	0	7	0	2.0	HC&S Contact Completed 12/31/2018	26.8%	31.5%	31.5%	32.5%
2019	201	251	41	(40)	8	0	2.3	Decommission Kahului Units 1, 2, 3, 4 5 x 8 MW ICE in service 10 MW Wind in service	24.9%	30.2%	30.2%	31.4%
2020	202	251	0	0	9	0	2.3		24.1%	30.0%	30.0%	31.2%
2021	204	251	0	0	9	0	2.3		23.0%	29.0%	29.0%	30.1%
2022	205	254	8	(6)	10	0	2.3	Decommission Maalaea Unit 7 1 x 8 MW ICE in service	23.9%	29.9%	29.9%	31.1%
2023	205	254	0	0	10	0	2.3		23.5%	29.5%	29.5%	30.7%
2024	205	257	25	(22)	10	0	2.3	Decommission Maalaea Units 4, 5, 6, 9 25 MW Geothermal in service	25.1%	31.2%	31.2%	32.4%
2025	205	257	0	0	10	0	2.3		25.0%	31.0%	31.0%	32.2%
2026	204	251	0	(5)	10	0	2.3	Decommission Maalaea Unit 8	23.0%	29.0%	29.0%	30.1%
2027	203	251	0	0	10	0	2.3		23.9%	30.0%	30.0%	31.2%
2028	200	251	0	0	10	0	2.3		25.8%	32.1%	32.1%	33.3%
2029	198	251	0	0	10	0	2.3		27.2%	33.6%	33.6%	34.8%
2030	194	239	0	(12)	10	0	2.3	Decommission Maalaea Unit 13	23.2%	29.5%	29.5%	30.8%
Total			78	(101)								

Table 5-1. Reserve Margin for the Maui Preferred Plan

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

Capacity Value of Demand Response

The demand response programs identified in the *Integrated Demand Response Portfolio Plan* (IDRPP) that provide capacity value are included in the calculation for the reserve margin.[31]

Capacity Value of Variable Generation

Future wind resources are assigned a capacity value of 3% of nameplate capacity. This 3% 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.

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

Lana‘i and Moloka‘i

Generation resources on Lana‘i and Moloka‘i were determined to provide sufficient capacity to meet our customers’ needs over the planning period.

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. The criteria and requirements for developing a plan to adequately accomplish this was described, in part, in Chapter 4. After 2016, all the generation and transmission planning criteria are met to achieve the unprecedented levels of RPS in the Preferred Plan.

[31] See Appendix F for details on the assumptions used in the PSIP.

GENERATION AND ENERGY MIX

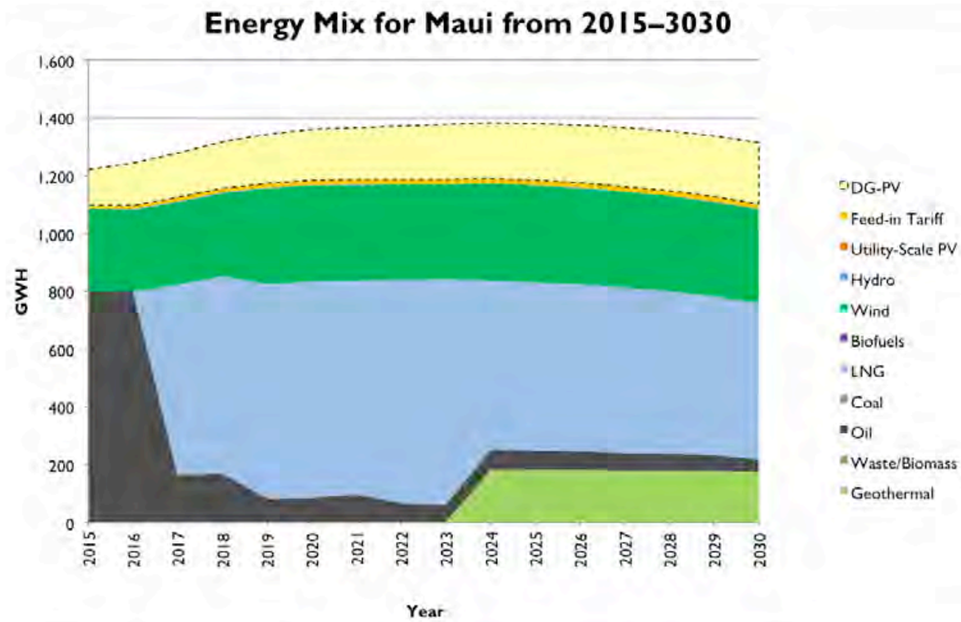

Figure 5-4. Annual Generation Portfolio: Maui

The generation mix has increasing levels of renewable energy replacing fossil generation. Renewable energy from distributed PV continues to grow over time and new wind and geothermal are also added to the system. As firm generating units are decommissioned, new flexible firm generation is added in its place.

A summary of the generation resources providing this portfolio mix over time is shown in Table 5-2 below.

Generation Resources for the Maui 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
KWP1	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Auwahi	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
KWP2	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Makila 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	X
20 MW BESS (Contingency)					X	X	X	X	X	X	X	X	X	X	X	X
20 MW BESS (Regulation)					X	X	X	X	X	X	X	X	X	X	X	X
HC&S	X	X	X	X												
Kahului 1	X	X	X	X	X	Decommissioned										
Kahului 2	X	X	X	X	X	Decommissioned										
Kahului 3	X	X	X	X	X	Decommissioned										
Kahului 4	X	X	X	X	X	Decommissioned										
Maalaea 1	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Maalaea 2	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Maalaea 3	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Maalaea 4	X	X	X	X	X	X	X	X	X	Decommissioned						
Maalaea 5	X	X	X	X	X	X	X	X	X	Decommissioned						
Maalaea 6	X	X	X	X	X	X	X	X	X	Decommissioned						
Maalaea 7	X	X	X	X	X	X	X	Decommissioned								
Maalaea 8	X	X	X	X	X	X	X	X	X	X	X	Decommissioned				
Maalaea 9	X	X	X	X	X	X	X	X	X	Decommissioned						
Maalaea 10	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Maalaea 11	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Maalaea 12	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Maalaea 13	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	Decommissioned
Maalaea 14	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Maalaea 15	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Maalaea 16	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Maalaea 17	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Maalaea 18	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Maalaea 19	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Maalaea X2	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Maalaea X2	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Hana	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
ICE 1					X	X	X	X	X	X	X	X	X	X	X	X
ICE 2					X	X	X	X	X	X	X	X	X	X	X	X
ICE 3					X	X	X	X	X	X	X	X	X	X	X	X
ICE 4					X	X	X	X	X	X	X	X	X	X	X	X
ICE 5					X	X	X	X	X	X	X	X	X	X	X	X
ICE 6								X	X	X	X	X	X	X	X	X
Geothermal										X	X	X	X	X	X	X

Table 5-2. Generation Resources for the Maui Preferred Plan, 2015–2030

DG-PV continues to increase from 2015 through 2030. DG-PV resources can possibly be obtained through either customer rooftop or larger-scale community solar projects.

In 2017, Maʻalaea Units M14, M16, M17, and M19 combustion turbines are converted to use LNG. Kahului Unit 3, Kahului Unit 4, one dual-train combined cycle, and one single-train combined cycle units are designated as must run for system security.

In 2019, Kahului Power Plant is decommissioned and ten megawatts (MW) of wind is added to the system. Two LNG fired 8.14 MW internal combustion engines (ICE) are installed at Waena as cycling units. Three ULSD-fired 8.14 MW ICE are installed in South

Maui for contingency and capacity purposes. One dual-train combined cycle unit and one single-train combined cycle unit are designated as must run with a 20 MW regulating reserve energy storage system for system security.

In 2024, a 25 MW geothermal plant is installed. Two ICE units would be relocated from South Maui to Waena, converted to LNG, and operated as cycling units. One dual-train combined cycle unit and a new geothermal plant are designated as must run with a 20 MW regulating-reserve energy storage system for system security.

Renewable Generation Resource Mix

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. Table 5-3 depicts the RPS percentages attained through the Preferred Plans for Hawaiian Electric, Maui Electric, Hawai'i Electric Light, and consolidated for all three utilities.

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

Table 5-3. 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.

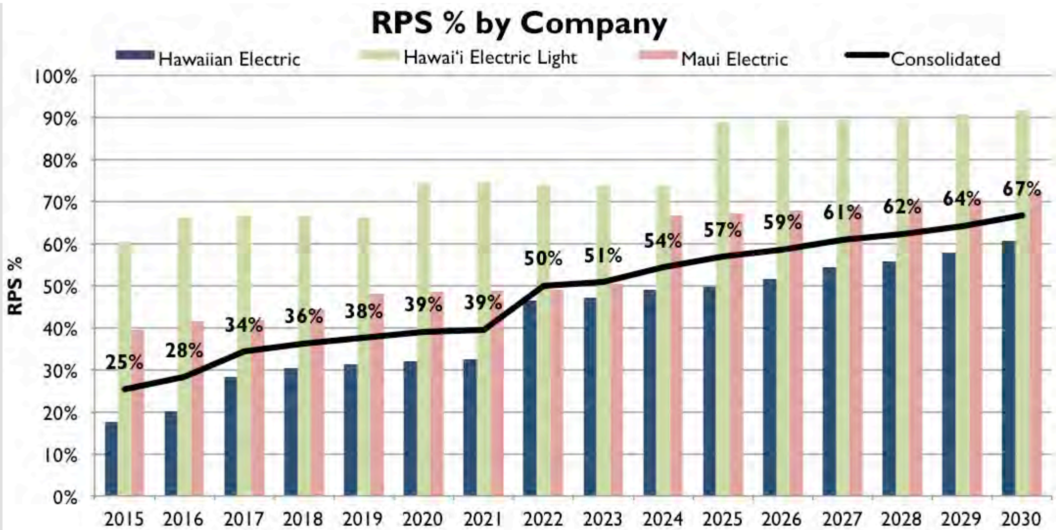

Figure 5-5. Consolidated RPS of Hawaiian Electric Companies Preferred Plans

For the Maui Electric Preferred Plans for Maui, Lana'i, and Moloka'i, the RPS would almost double from 2015 to 2030, from 41% to 72%, respectively, as shown in Figure 5-6 below. The relative contribution of distributed generation photovoltaic (DG-PV also referred to as "rooftop PV") would be almost one-third of the RPS value.

Our forecasts indicate that we can meet 40% renewable energy utilization by 2018. In 2019, the retirement of the units at Kahului Power Plant, the addition of ICE units, the addition of ESS (Energy Storage Systems), and the addition of 10 MW of wind, renewable energy utilization will allow us to meet 45% annually through 2023. With the addition of a geothermal resource in 2024, renewable energy utilization will exceed 65%. Demand response programs are also implemented during this period and contribute to increasing renewable energy. Our forecast indicates that we will achieve 129 MW of DG-PV on the Maui system by 2030.

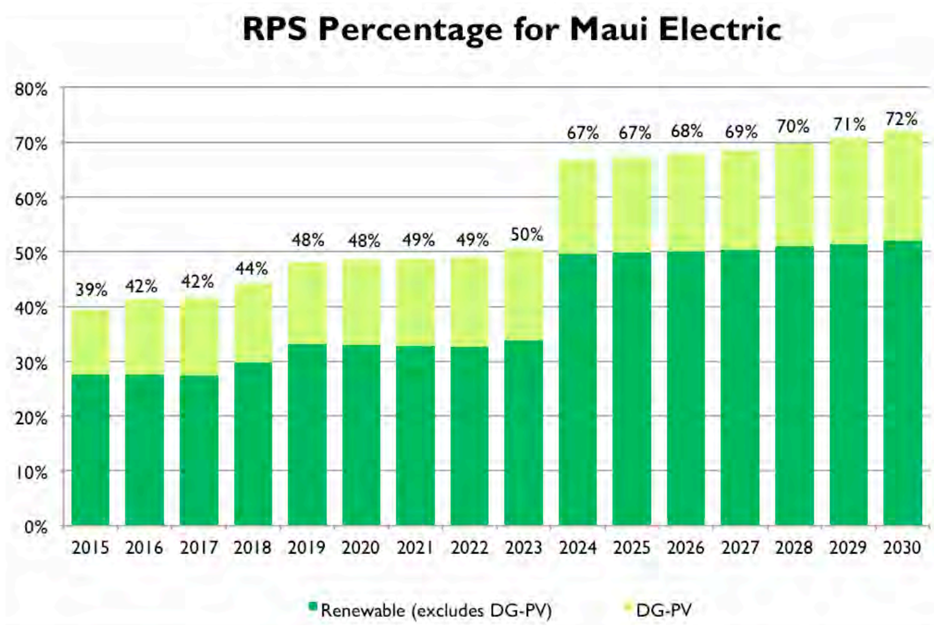

Figure 5-6. Maui Electric Preferred Plans RPS

We performed analyses incorporating existing generating resources, demand response programs, and new generating resources to develop a Preferred Plan that increases the amount of renewable generation accepted and minimizes costs relative to the other resources considered. It contains a mix of resources that allows for increased renewable energy on the Maui system including DG-PV, additional wind, and a new geothermal resource. Geothermal is a firm renewable generation resource that can provide cost-effective must run generation.

The overall mix of renewable energy resources contributing to the RPS in 2030 is shown in Figure 5-7.

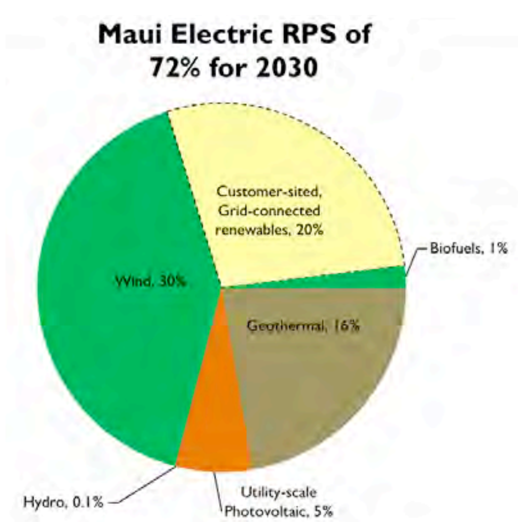

Figure 5-7. 2030 RPS for Maui Electric Preferred Plans

Figure 5-8 below shows that the system is able to utilize (that is, not curtail) 95.8% to 99.2% each year of the renewable energy that is produced throughout the planning period.

% RE Utilized	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2015-2030
	98.3%	97.0%	98.2%	98.4%	98.2%	98.3%	98.2%	98.1%	97.9%	99.2%	99.1%	98.9%	98.7%	98.5%	98.2%	97.9%	98.4%

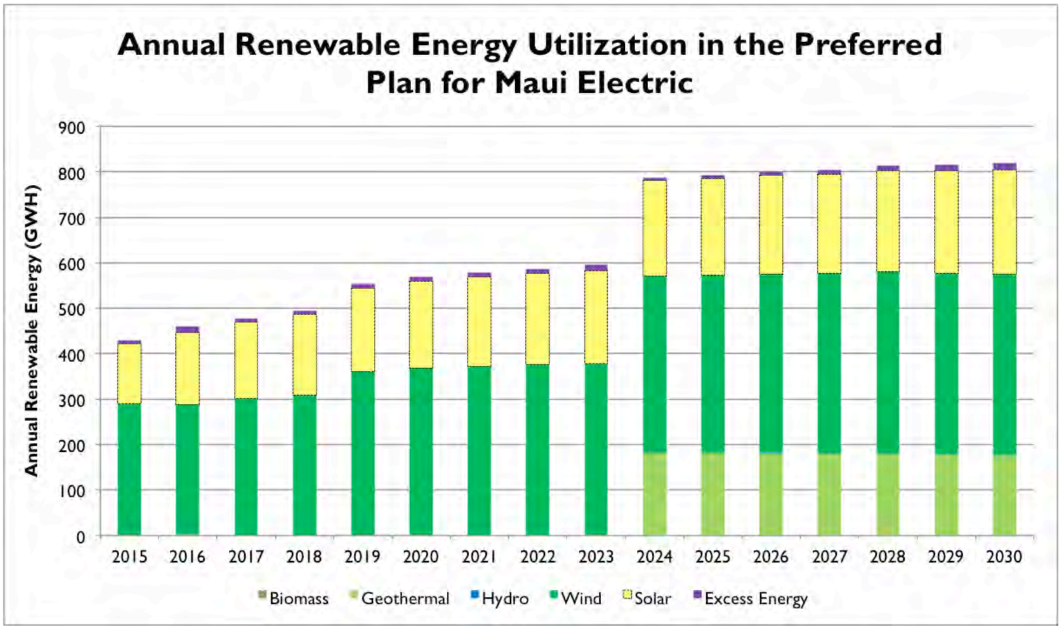

Figure 5-8. Total Maui System Renewable Energy

Annual Fuel Consumption

In alignment with our vision, the Preferred Plan reduces the reliance on imported fossil fuels to Maui. With the addition of new variable renewable resources and new firm renewable resources, we are able to reduce the total amount of fossil fuel consumption.

Figure 5-9 through Figure 5-11 show how the annual fuel consumption for Maui, Lana‘i, and Moloka‘i, respectively, decreases as the mix of generation changes over the analysis period.

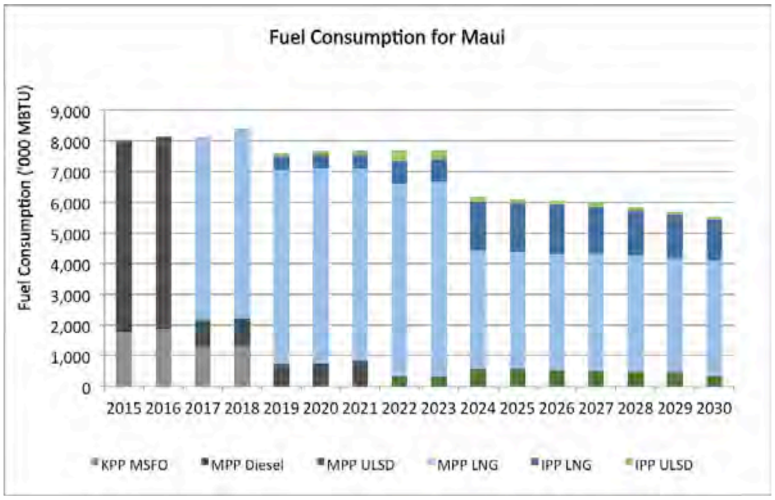

Figure 5-9. Annual Fuel Consumption for Maui

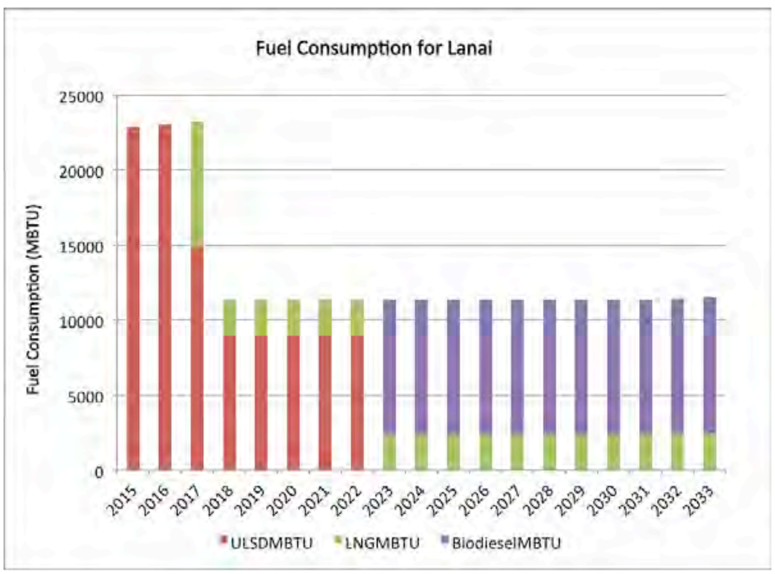

Figure 5-10. Annual Fuel Consumption for Lana‘i

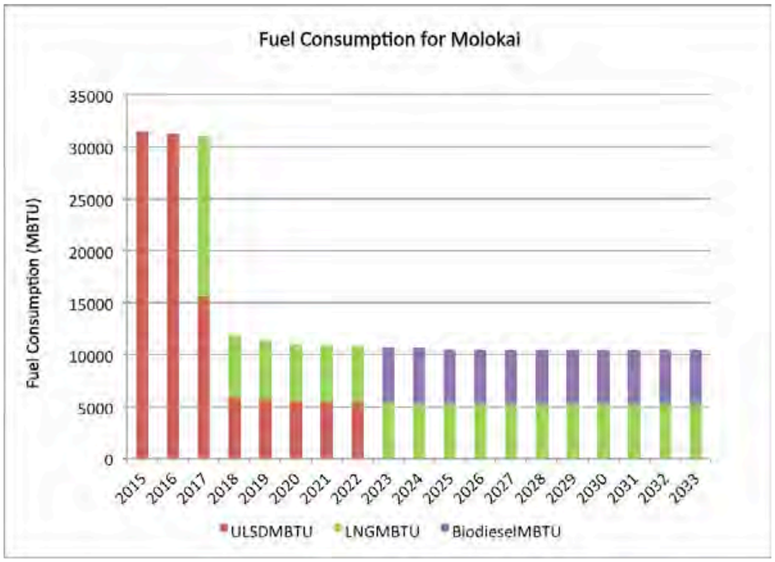

Figure 5-11. Annual Fuel Consumption for Moloka'i

As we introduce new resources to the system and retire Maui Electric's generating units from 2019 to 2030, the fossil fuel consumption of the power system on each island decreases. The annual fuel consumption of Maui Electric's baseload and cycling generating units decrease, as shown in Figure 5-12 below, as existing generating units are retired and renewable energy is added to the system.

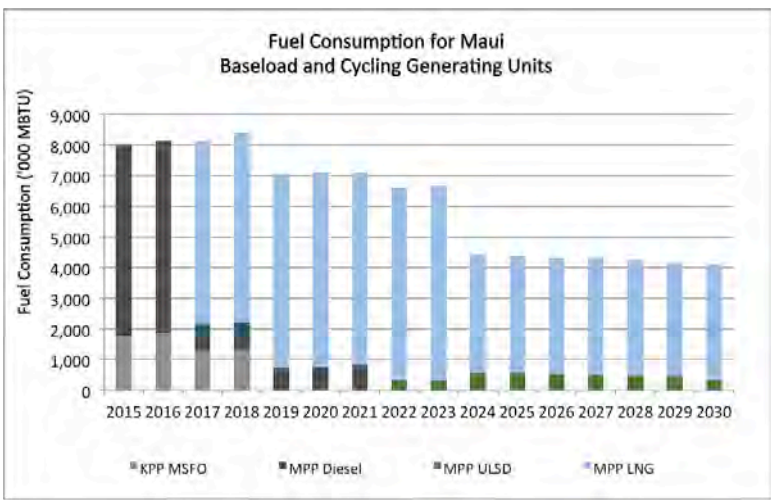

Figure 5-12. Annual Fuel Consumption for Maui Baseload & Cycling Generating Units

Annual Capacity Factors for Each Resource

Our generation portfolio constantly evolves based on the needs of our customers and our community. System load changes as energy efficiency programs, demand response programs, and DG-PV mature. The remaining system load is provided by a mix of utility and IPP generation. The mix of generation also evolves as existing resources are decommitted or the contract terms of power purchase agreements are completed. New generation resources are added to the system accordingly.

Table 5-4 for years 2015, 2020, 2025, and 2030 shows the annual capacity factors of each generating resource on the Maui system.

Units	Type	Capacity Factor			
		2015	2020	2025	2030
Kahului 1	Thermal Steam	0%	–	–	–
Kahului 2	Thermal Steam	7%	–	–	–
Kahului 3	Thermal Steam	64%	–	–	–
Kahului 4	Thermal Steam	53%	–	–	–
Ma'alaea X1	Internal Combustion Engine	2%	0%	0%	1%
Ma'alaea X2	Internal Combustion Engine	3%	0%	0%	0%
Ma'alaea 1	Internal Combustion Engine	6%	0%	0%	1%
Ma'alaea 2	Internal Combustion Engine	5%	0%	0%	0%
Ma'alaea 3	Internal Combustion Engine	4%	0%	0%	1%
Ma'alaea 4	Internal Combustion Engine	13%	0%	–	–
Ma'alaea 5	Internal Combustion Engine	6%	0%	–	–
Ma'alaea 6	Internal Combustion Engine	13%	1%	–	–
Ma'alaea 7	Internal Combustion Engine	1%	0%	–	–
Ma'alaea 8	Internal Combustion Engine	11%	1%	3%	
Ma'alaea 9	Internal Combustion Engine	8%	2%	–	–
Ma'alaea 10	Internal Combustion Engine	49%	13%	21%	13%
Ma'alaea 11	Internal Combustion Engine	40%	8%	14%	11%
Ma'alaea 12	Internal Combustion Engine	32%	26%	8%	6%
Ma'alaea 13	Internal Combustion Engine	22%	20%	7%	
Ma'alaea 14-15-16	Dual-Train Combined Cycle	83%	73%	81%	77%
Ma'alaea 17-18-19	Dual-Train Combined Cycle	24%	79%	9%	10%
Hana	Internal Combustion Engine	0%	0%	0%	0%
HC&S	Biomass	0%	–	–	–
KWP1	Wind	44%	44%	44%	44%
AWE	Wind	52%	52%	52%	51%
KWP2	Wind	42%	44%	44%	42%
New Wind 1	Wind	–	46%	48%	45%
Geothermal	Geothermal	–	–	83%	81%
Makila Hydro	Run-of-River Hydro	23%	23%	23%	23%
8 MW ICE 1	Internal Combustion Engine	–	8%	20%	14%
8 MW ICE 2	Internal Combustion Engine	–	5%	56%	48%
8 MW ICE 3	Internal Combustion Engine	–	3%	51%	44%

Units	Type	Capacity Factor 2015	2020	2025	2030
8 MW ICE 4	Internal Combustion Engine	–	33%	46%	38%
8 MW ICE 5	Internal Combustion Engine	–	27%	42%	34%
8 MW ICE 6	Internal Combustion Engine	–	–	36%	29%
DG-PV	Solar Photovoltaic	19%	19%	19%	19%
FIT Solar	Solar Photovoltaic and Concentrated Solar Power	19%	19%	19%	18%

Table 5-4. Total System Renewable Energy: Maui

ROLES OF GENERATION RESOURCES

Our system has evolved with the addition of variable renewable resources; both developer and customer owned, in the form of solar, hydroelectric, and wind technologies. Variable renewable resources have changed the system stability requirements that Maui Electric and Independent Power Producers need to adapt to, in order to continue to provide safe, reliable power to all customers.

Our vision of a future with even greater renewable generation on the system requires that new renewable generation has the operating characteristics that contribute to system stability to maintain and improve the reliability. Our current generation fleet is comprised of firm capacity resources that have provided system security and safe, reliable power for many years. As our firm fossil fuel generators are retired, the flexibility from these units must be provided by new renewable resources.

Utility-Owned Generation Retirements

Roles of Current Generation

The current generation fleet of Maui Electric is comprised of:

- Four (4) Steam Units: located at the Kahului Power Plant, these units provide firm generation, regulating reserve, system inertia, voltage support to Central Maui, and contribute to system security. These units use an industrial fuel oil that is lower cost than diesel.
- Two (2) Dual-Train Combined Cycle units: located at the Maʻalaea Power Plant, these units are the most efficient generating resources on the island. These units provide firm generation, regulating reserve, and system inertia. These units can start and provide generation in a relatively short time period.

- Fifteen (15) Internal Combustion Diesel Engines: located at the Maʻalaea Power Plant, these units provide firm generation and regulating reserve. These units can start and provide firm generation in a relatively short time period. Five of these units (X1, X2, M1, M2, and M3) are quick-starting units that can be used for emergency and as a transition unit to starting a larger diesel unit.
- Two (2) Internal Combustion Diesel Engines: located in Hana, these units provide firm generation and primarily provide support to the Hana area during transmission maintenance and system disturbance.
- Eight (8) Internal Combustion Diesel Engines: located in Lanaʻi–Miki Basin. These units can start and provide firm generation in a relatively short time period.
- Nine (9) Internal Combustion Diesel Engines: located in Molokaʻi–Palaʻau. These units can start and provide firm generation in a relatively short time period.
- One (1) Combustion Turbine Engine: located in Molokaʻi–Palaʻau. This unit provides firm generation and peaking load capability.

The existing Maui Electric generation fleet is expected to perform in the future as follows:

- Four (4) Steam Units at Kahului Power Plant: these units will continue to operate in their present configuration until retirement in 2019.
- Two (2) Dual-Train Combined Cycle Units at Maʻalaea Power Plant:

  One of the dual-train combined cycle units is scheduled to be modified to operate at a lower capacity minimum level and will transition to LNG fuel starting in 2017. This unit will continue to operate as a must run generating unit and contribute to system security, but operation at lower load levels will allow more opportunity to integrate variable renewable energy when available, and transition to LNG will lower cost to customers.

  The other dual-train combined cycle unit will be held offline and operated in simple cycle or combined cycle as needed. This unit is also scheduled to transition to LNG fuel starting in 2017. To comply with system security and operate a high efficiency, low-fuel-cost resource, this unit will be operated in single-train combined cycle and designated as must run starting in 2017. In 2024, this unit will be removed from must run designation and replaced with a geothermal resource. The geothermal resource is expected to contribute to system security at the same level as the single-train combined cycle unit it will replace.

- Fifteen (15) Internal Combustion Diesel Engines: These units will remain offline and be available for contribution to system security and system load as needed after other offline non-fossil fuel resources, such as DR and energy storage, have been used to its fullest availability and ability. Units will be retired in accordance with Table 5-5.

- Two (2) Internal Combustion Diesel Engines at Hana: these units will continue to be operated to support the Hana area.

Additional Renewable Generation Integration

The existing Maui Electric generation fleet has operating characteristics that are quick-starting, flexible, fuel-efficient, and dispatchable to accommodate the integration of existing and additional variable renewable energy resources without significant curtailment.[32]

Quick-starting generation has the ability to remain offline until it is required to support the system, such as during a large down ramp event when the wind or solar resources suddenly become unavailable. Other units that may need additional time to start and connect to the system will need a resource to bridge the time required to supply generation (for example, demand response and energy storage).

- Maʻalaea diesel generating units MX1, MX2, M1, M2, and M3 can be started and synchronized to the system in 3 minutes.
- The combustion turbines (Maʻalaea units M14, M16, M17, and M19) can be started and synchronized to the system in less than 20 minutes in simple-cycle mode.
- Maʻalaea diesel generating units M10, M11, M12, and M13 can be started and synchronized to the system in less than 20 minutes.
- Maʻalaea diesel generating units M4, M5, M6, M7, M8, and M9 can be started and synchronized to the system in less than 40 minutes.

Flexible generation refers to units that can be held offline until called upon for generation, allowing us to maximize variable renewable generation. All Maʻalaea generating units are flexible.

The most fuel efficient units on the Maui system are the dual-train combined cycle units.

Units that have operating ranges that can ramp up and down to follow the system load as well as the variable energy production of the available generating resources to reduce curtailment include M4–M13, DTCC1, and DTCC2.

Retirement Schedule

Our vision of providing a future with more renewable energy, while also minimizing cost impacts to customers, requires our fossil fueled generating units to be replaced with new generating resources. Although new generation resources require capital investment, we anticipate the addition of these new resources will lower future energy costs compared with the current energy mix, and over time, our customers will be able to

[32] The thermal generation fleet on Lanaʻi and Molokaʻi is comprised of flexible, quick-starting units.

realize the cost benefits. Retiring existing generation will also reduce dependency on fossil fuels.

Table 5-5 is Maui Electric's retirement plan for its existing fossil fuel generating resources.

Unit Description	Unit Rating (MW)	Retirement Date
Kahului Unit 1	4.71	2019
Kahului Unit 2	4.76	2019
Kahului Unit 3	10.98	2019
Kahului Unit 4	11.88	2019
Ma'alaea Unit 7	5.51	2022
Ma'alaea Unit 4	5.51	2024
Ma'alaea Unit 5	5.51	2024
Ma'alaea Unit 6	5.51	2024
Ma'alaea Unit 9	5.48	2024
Ma'alaea Unit 8	5.48	2026
Ma'alaea Unit 13	12.34	2030

Table 5-5. Fossil Fuel Generation Retirement Plan

Fossil Fuel Generation Retirement Plan

The units at the Kahului Power Plant are scheduled for retirement to comply with environmental standards. These units provide firm capacity and contribute to system security. Therefore, replacement firm generating ICE units are planned to be installed in 2019, and an ESS is planned to be in service on the Maui system in 2019 to provide system security.

The Maʻalaea generating units that are scheduled for retirement will be replaced with more cost effective, flexible ICE generation and a lower energy cost generation resource (for example, geothermal). Maʻalaea generating units are also retired when the system peak load is forecasted to decline and there is an anticipation of excess firm capacity.

To account for existing unit retirements and ensure adequate amounts of firm generation on the Maui system, new firm generation must be installed. We will pursue new firm generation through a competitive procurement process (described below).

Several of our existing generating units will not be retired during the PSIP analysis period.

Key Generation Units

The units listed below provide benefits to the Maui system that include system security, minimized costs through efficiency and low cost LNG fuel, or flexibility.

- Dual-Train Combined Cycle units: high efficiency, low LNG fuel cost, provides regulating reserves, provides contingency reserves.
- Combustion Turbines: low LNG fuel costs, operational flexibility through startup availability and dispatch.
- Small diesel internal combustion engines (MX1, MX2, M1, M2, M3): quick-starting
- Mid-size diesel internal combustion engines (M10, M11, M12): operational flexibility through startup availability and dispatch.

It is also anticipated that the small and mid-size diesel units will be operated very infrequently, as they will be designated to operate during peak load periods or when variable renewable resources are un-available.

Must-Run Designations

We are committed to providing our customers safe and reliable power at all times. To accomplish this, system security and stability is our first priority. A combination of firm generating resources and resources that provide system reserves will ensure that the system demand is met. As we have incorporated significant amounts of variable renewable energy on our system, system security requirements have changed, prompting adjustment in the operation of existing resources. Our system security needs will continue to evolve with our generation resource mix as we continue to increase our renewable energy portfolio.

The high penetration of variable renewable resources on our system creates new challenges to maintaining system security and stability. Must-run generation can be reduced to allow the system to accept more renewable energy, but the generation resource configuration and operational practices must be adjusted to ensure that system security is not compromised.

Table 5-6 shows the units that are designated as must-run and the additional resources that are required to meet the system security requirements.

Year	Must-Run Resources	Regulating Reserve Resource	Contingency Reserve Resource	System Security Criteria
2015	DTCC1; K3, K4			Non-Compliant
2017	DTCC1, STCC2, K3, K4			Compliant
2019	DTCC1, STCC2	Add 20 MW: 10 MWh BESS	Add 20 MW: 30 Minute BESS	Compliant

2024	DTCC1, Geothermal (25MW)			Compliant

Table 5-6. Must-Run Designations

To reduce must-run generation while increasing variable renewable generation, we will need to add resources without minimum load settings that can provide reserve requirements that will comply with system security criteria. Reducing fossil fueled must-run generation will reduce fossil fuel generation costs, but it will require capital investment in new resources, such as batteries, and will increase power purchase payments to independent power producers.

For the island of Lana'i, Miki Basin Units 7 & 8 are designated as must run during the day to meet system security needs.

For the island of Moloka'i two (2) of the baseload-capable units (Pala'au units 7, 8, and 9) must run during the day to meet system security needs.

Must-Run Generation Designation Plan

System reliability will remain our priority, with efforts also focused on reducing our energy costs by reducing fossil fuel generation and transitioning to LNG. Maui Electric will also implement DR programs as described in the IDRPP[33] that will contribute to system reliability and reduce fossil fuel consumption.

The action plan in Table 5-7 follows the must-run designations listed in Table 5-6, and utilizes the high efficiency of the existing dual-train combined cycle units to comply with system reliability criteria.

#	Description	Target Date	Benefit
1.	Acquire LNG	2017	Low cost fuel
2.	Modify DTCC1 and DTCC2 to use LNG	2017	High efficiency units using low cost fuel
3.	Modify DTCC1 to operate at lower minimum operating levels	2017	Accommodate integration of existing and substantial additional variable renewable energy
4.	Retire all units at Kahului Power Plant (Units K3 and K4 are must-run units)	2019	Accommodate integration of existing and substantial additional variable renewable energy
5.	Add 20MW 10 MWh Regulating Reserve BESS	2019	Accommodate integration of existing and substantial additional variable renewable energy by reducing regulating reserve requirement provided by fossil fuel generation

[33] The Companies filed its *Integrated Demand Response Portfolio Plan* (IDRPP) with the Commission on July 26, 2014.

#	Description	Target Date	Benefit
6.	Add 20MW 30-Minute Contingency Reserve BESS	2019	Allow for a non-fossil fuel, offline resource to provide system security for a contingency event in lieu of online fossil fuel resource
7.	Add Internal Combustion Engines	2019	Flexible, firm generating units. Quick starting capability allows ICE to remain offline until called upon to support the system.
8.	Retire Ma'alaea diesel internal combustion engine, Unit M7	2022	Retire less efficient diesel unit
9.	Add Internal Combustion Engine	2022	Flexible, firm generating unit. Quick starting capability allows ICE to remain offline until called upon to support the system.
10.	Add 25MW Geothermal must-run resource	2024	Add low energy cost, firm renewable resource to provide system security
11.	Remove must-run designation from DTCC2	2024	Accommodate integration of existing and substantial additional firm (geothermal) and variable renewable energy
12.	Retire Ma'alaea diesel internal combustion engines, Units M4, M5, M6, M9	2024	Retire less efficient diesel units
13.	Retire Ma'alaea diesel internal combustion engine, Unit M8	2026	Retire less efficient diesel unit
14.	Retire Ma'alaea diesel internal combustion engine, Unit M13	2030	Retire less efficient diesel unit

Table 5-7. Action Plan for Reducing Must-Run Generation

Procurement of Replacement/New Generation

The PSIPs for O'ahu and Maui identify replacement generation being needed in 2022 and 2019, respectively. In addition, DR programs and ESS that are expected to provide capacity reserves for both island power systems will be implemented in the immediate future. The most urgent replacement generation is needed on Maui Island, as it would support 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.

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 reserve 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 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.

Flexibility for Integrating Additional Renewable Generation

Reductions in must-run generation, regulating reserves provided by flexible resources or generation (such as ESS, DR, and ICE), and load shifting resources (such as storage and DR on our system) will allow us to integrate more renewable generation on our system.

To support our commitment to increasing renewables on the system, the units at the Kahului Power Plant are scheduled for decommission in 2019. They will be replaced with firm generating resources in the form of Internal Combustion Engines (ICE). In addition to providing firm capacity, the ICE units are designed to start and stop multiple times a day and can provide ramping capability. An ESS will also be added to the system to provide regulating reserves.

The Preferred Plan also adds demand response programs that shift loads to reduce curtailment and reduce the load during peak electrical consumption periods. Demand response programs also provide reserves that assist the system during periods when variable renewable resources are not available to contribute to the system.[34]

Roles of Existing Independent Power Producer (IPP) Generation

Over the period of the PSIP analysis, there are three existing IPP have Power Purchase Agreements (PPA) that are expiring:

- HC&S: expiration date 2014[35]
- Makila Hydro: expiration date 2026
- Kaheawa Wind Power I, LLC (KWP1): expiration date 2026

[34] ICE units can also be utilized when demand response and ESS resources have been used to their limitations.

[35] Assumes HC&S contract extended through 2018 for PSIP analysis

We plan to negotiate extensions to all expiring PPAs. However, PPA extensions need to be in the best interest of the community and customers. Substantially lower costs are expected, as the period for recovery of project development and execution costs has been completed. If renegotiations do not result in substantially lower costs, then we will pursue replacement renewable generation through a competitive procurement process similar to the described above.

HC&S

In addition to providing firm renewable power to the Maui grid, HC&S also provides the most necessary ancillary services, including emergency power, voltage and frequency regulation, and system inertia. As more variable renewable resources are integrated on the Maui system, the conventional thermal generation provided by HC&S becomes increasingly important because it can adjust its output based on system conditions.

Electric water pumps are an integral part of HC&S's irrigation system[36]. HC&S configures their generating facilities to provide for automatic shedding of their irrigation water pump load (and factory), to provide additional immediate power to meet sudden and severe failures on the Maui grid[37]. The system protection provided by HC&S at any time shall not exceed the sum of the firm power which would otherwise be required under the PPA plus four (4) MW; provided, however, that in no event shall the maximum exceed sixteen (16) MW. HC&S has no obligation to provide system protection during their shutdown periods.

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 138 kV transmission system through a transmission loop from the central area to the northern area of the island. Currently, O‘ahu's 138 kV 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

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[36] HC&S requires approximately 200 million gallons of water per day to sustain its 36,000 acres of sugarcane.

[37] In accordance with PPA.

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 and Moloka‘i[38] remains the same. However, the PSIP identifies transmission upgrades 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 Hawai‘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

[38] Lana‘i does not have transmission lines.

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 system over the planning period, the Company'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,[39] 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 our 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 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.

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.

[39] *Smart Grid Roadmap and Business Case*, filed with the Commission on March 18, 2014.

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

1. **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.
2. **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, Hawaiʻi 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 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 goal:

- 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.
- Foster innovation and build internal operating experience through energy storage research and development activities.

The Companies are willing to consider multiple mechanisms in support of achieving the goal of developing a resource portfolio enabling lower costs and reliable power for our customers.

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 with a broad portfolio of assets consisting of 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.
- **Own and operate energy storage assets only when in the best interest of customers.** When energy storage is shown to be a viable alternative, the Companies' preference will be to own and operate energy storage systems. However, various business and ownership models, as well as service contracting arrangements, will be considered to best meet the Companies' strategic goals objectives and customer needs.
- **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).
- **Balance system security with public policy-based renewable energy goals.** The planning and implementation of energy storage is, in part, driven by system security and reliability requirements as additional amounts of variable renewable energy generation drive the need for additional grid services.
- **Pursue cost-effective energy storage by balancing cost with system reliability.** The costs to implement energy storage systems will be a factor in project development decisions as financial impacts to customers must be considered when integrating

renewable energy resources. Therefore, it is critical that business decisions be based on best-available pricing intelligence (current and future), and a clear understanding of the cost benefits that the energy storage asset can provide to the system.

- **The timing of the Companies' plans to deploy energy storage and enter into contracts for services will consider technology maturity and 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 and 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[40];
- 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, 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)

[40] 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.

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 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 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 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 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 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*[41] (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.

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 be immediately 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

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

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 5-8 shows the energy storage additions that are in the preferred plan (demonstration projects are not shown in the tables).

Year Installed	Capacity	Type of Storage Device	Storage Duration	Purpose
2015 (Moloka'i)	2 MW (committed project)	Battery	11 min	Frequency regulation; 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; DG-PV support
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 5-8. Maui Electric Preferred Plan Energy Storage Additions

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 Lana'i, 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 21MW 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 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 Molokaʻi

Maui Electric, in collaboration with HNEI, is currently pursuing a 2MW/375 kWh battery energy storage project on the island of Molokaʻi 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.

GENERATION PORTFOLIO OF AN OʻAHU–MAUI GRID INTERCONNECTION

Two independent analyses were developed to test the economics of constructing a 200 MW DC bi-directional transmission tie between the islands of Maui and Oʻahu. The analysis was designed to identify the potential savings in power costs created by the cable. The forecast of savings then creates the benchmark, "the price to beat", for owning and operating the transmission cable. In our analysis we did not explicitly analyze additional system security costs that could be potentially incurred if the cable configuration was one 200 MW cable versus two 100 MW cables. A redundant connection (two 100 MW cables) has potential system benefits since the N-1 contingency is closer to the current system requirements versus the alternative of the largest outage potentially being 200 MW. The trade-off for the redundant cables is likely to be close to a doubling in the cost of constructing the transmission link.

The independent analyses were performed by Black & Veatch and PA Consulting, members of the modeling team assembled for the PSIP analyses. The production cost simulation models used by both firms in this analysis are described in Appendix C. The analyses used slightly different approaches. One approach is not considered preferred to the other, rather the different approaches provide different perspectives. The conclusion from the analysis of both companies indicates that the transmission cable is not a cost-effective solution. The cable could not possibly be built for the estimated amount to be cost-effective. Based upon the two analyses, the NPV of the estimated savings excluding the cost of the transmission cable are $60 M–$ 175 M, respectively. For the cable system to be cost effective, the NPV for the design, construction, operation, and maintenance of the cable system would have to be less these amounts.

A discussion of the analyses performed follows.

PA Consulting Analysis

PA Consulting developed an analysis of the transmission cable potential benefits using the AURORA hourly production simulation model. Six cases were developed where PA Consulting allowed the AURORA model to use its long-term expansion algorithm to develop the least cost generation expansion plan subject to constraints and certain assumptions. The major assumptions and constraints included:

- Starting with the existing generation assets on Maui and Oʻahu.
- Assuming that LNG would be available on both islands starting in 2017.
- Assuming that distributed generation (that is, DG-PV) would be built out on both islands.

- Generator operating characteristics, operating costs, new unit costs, and fuel costs consistent with the assumptions documented in this document.

Six cases were modeled and in each case the Aurora model was allowed to identify the least cost generation mix. The six cases were combined to create four scenarios and create a range of estimated savings.

1. Thermal Future with No Grid Tie. In this scenario, the model was not allowed to select new utility-scale wind and solar projects beyond the projects that have already been included in the Base Case for Maui. These scenarios roughly tied to the base case scenarios developed for each of the islands.

2. Grid Tie–Thermal Future. In this scenario, the model selected the least cost generation expansion plan assuming the two islands were connected by a 200 MW transmission link. The two systems were modeled as one pool where they shared a reserve margin and the system was jointly dispatched subject to the transfer constraint between the islands. The model was constrained to not selecting new utility-scale wind or solar beyond projects already included in the Base Case for Maui.

3. Renewable Future with No Grid Tie. In this scenario, the model was allowed to select the least cost mix of resources including utility-scale wind and solar.

4. Grid Tie–Renewable Future. In this scenario, the model selected the least cost generation expansion plan assuming the two islands were connected by a 200 MW transmission link. The two systems were modeled as one pool where they shared a reserve margin and the system was jointly dispatched subject to the transfer constraint between the islands.

Black & Veatch Analysis

The Oʻahu-to-Maui transmission cable analysis was based on the assumption that each island would need to be able to meet both load and system security requirements independently; that is, each island could continue to provide energy and grid stability in the event that the transmission cable failed. Thus, the analysis uses a base case that allows each island to meet its own requirements independently; this system configuration was maintained across the alternate cases evaluated. This base case includes distributed generation build-out; additional utility-scale renewable projects; LNG; and improvements to thermal fleet flexibility, efficiency, and reliability through retirements and new generation additions.

The potential benefit to the transmission cable stems from the difference in production cost between Oʻahu and Maui—particularly the potential for low-cost, higher-production wind generation. Thus, the Black & Veatch analysis considered additional wind installed on Maui and, via the transmission cable, energy was allowed to flow between Maui and

Oʻahu. Except for this additional wind on Maui, the remainder of the generating system remained consistent with the base case. Both the transmission cable and the additional Maui wind were modeled as online in 2022.

Since generation on the margin on Maui is cheaper than generation on Oʻahu, given the presence of a transmission cable, Maui generation will be used to meet Oʻahu demand. In absence of sufficient additional wind, Maui thermal units will run to assist in meeting Oʻahu demand, and Oʻahu thermal units will back down. As additional wind is installed on Maui, Oʻahu generation decreases, Maui thermal generation decreases, and Maui wind generation increases.

The optimum scenario evaluated by Black & Veatch incorporates an additional 300 MW of wind on Maui in 2022, coincident with the assumed online date of the transmission cable. This scenario saw significant (30%) decrease in non-renewable generation on Oʻahu. On Maui, renewable generation more than doubled. The resulting system-wide generation savings, excluding the cost of the interconnection transmission cable, would have an NPV of $80 million.

ENVIRONMENTAL COMPLIANCE

Environmental legislation, regulations, and governmental rules have increased dramatically in recent years, especially regarding air (Clean Air Act) and water (Clean Water Act). Maui Electric must comply with all environmental requirements but the following discussion focuses on several main areas:

- National Ambient Air Quality Standards (NAAQS)
- Greenhouse Gas (GHG)
- Regional Haze Rule
- Reciprocating Internal Combustion Engines National Emission Standards for Hazardous Air Pollutants (RICE NESHAP) Rule
- Toxic Substances Control Act (TSCA)
- National Pollution Discharge Elimination System

Maui Electric focused their analysis on NAAQS compliance.

Environmental Compliance Plan

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.

National Ambient Air Quality Standards (NAAQS)

In 2010, the EPA established two new, significantly more stringent, one-hour air quality standards for nitrogen dioxide (NO_2) and sulfur dioxide (SO_2). These standards apply to all sources in the state, which includes all Hawaiian Electric, Hawai‘i Electric Light, and Maui Electric generating stations.

Sulfur dioxide emissions can be controlled by either reducing the sulfur content in the fuel or by installing scrubbers coupled with ESPs to remove sulfur dioxide from exhaust gases. ESPs integrated with scrubbers can remove sub-micron droplets, acid mists, metals, and mercury particles. These controls also remove pollutants regulated by the MATS Rule and thus would provide for compliance with the MATS rule.

Nitrogen oxides (NOx) — nitric oxide (NO) and nitrogen dioxide (NO_2) — emissions can be controlled by combustion hardware improvements such as low NOx burners and overfire air and by the installation of selective catalytic reduction (SCR) systems.

EPA SO_2 NAAQS Implementation Strategy

EPA’s paper *Next Steps for Area Designations and Implementation of the Sulfur Dioxide National Ambient Air Quality Standard* (dated February 6, 2013) describes their updated one-hour SO_2 NAAQS implementation strategy. This strategy anticipates additional EPA rules and guidance, and addresses areas not currently proposed to be designated as nonattainment areas based on air monitoring data from 2009–2011.[42]

The EPA is not prepared to propose any designation action in Hawai‘i at this time. The agency is deferring action to designate areas in Hawai‘i while it continues to assess Hawai‘i’s request to exclude air quality monitoring data that exceeds the 2010 SO_2 standard under the Exceptional Events Rule due to SO_2 emissions from an active volcano.

On January 7, 2014, the EPA released two updated draft documents, SO_2 NAAQS Designations Modeling Technical Assistance Document and SO_2 NAAQS Designations Source-Oriented Monitoring Technical Assistance Document, which provide technical assistance for states implementing the 1-hour SO_2 standard. These updated draft documents provide technical advice on the use of modeling and monitoring to determine if an area meets the 1-hour SO_2 standard.

[42] EPA is not prepared to propose designation action in Hawai‘i. The agency is deferring action to designate areas in Hawai‘i while it continues to assess Hawai‘i’s request to exclude air quality monitoring data that exceeds the 2010 SO_2 standard under the Exceptional Events Rule due to SO_2 emissions from an active volcano (as stated in an EPA letter to Governor Neil Abercrombie, February 6, 2013).

Air agencies will also work with sources by establishing and submitting to the EPA enforceable emission limitations that ensure that the SO_2 NAAQS can be attained before the date that final designations are issued. Based on the EPA's February 6, 2013 updated implementation strategy, depending on whether a modeling or monitoring path is followed, the 1-hour SO_2 attainment deadlines range from December 2022 to December 2025. The EPA has indicated that this implementation schedule does not reflect any final agency action nor impose any legally binding or enforceable requirements. The timeline and milestones are therefore subject to change.

MECO NAAQS Compliance Strategy

MECO analyzed:

- Switching to lower sulfur fuels such as low sulfur industrial fuel oil (LSIFO), biofuels, or LNG only for the Ma'alaea combined cycle units.
- Installing AQC equipment on Kahului units 1 through 4.
- Retiring existing units and replacing them with new firm geothermal or biofuel generation.

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 (CO_2e) 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 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).[43]

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 state 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.

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.

Hawaiian Electric is 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. Hawaiian Electric is already taking active steps to mitigate contributions to global warming by investing in and committing to use biofuels, renewable generation, and energy conservation.

Regional Haze

Regional haze is essentially impaired visibility caused by human emissions and natural processes spread over a wide geographic area. The Clean Air Act required EPA to issue regulations to restore visibility for national parks and wilderness areas to levels that would exist if there were no human-made emissions—natural visibility.

EPA issued a Regional Haze Rule requiring states to establish interim goals toward attaining the final goal of natural visibility by 2064. EPA worked closely with Hawai'i to develop a Regional Haze Federal Implementation Plan (FIP) which became effective on November 8, 2012.

The FIP establishes an annual SO_2 emissions cap from Hawai'i Electric Light's three steam boiler facilities at Shipman, Hill, and Puna. The FIP provides flexibility for the

[43] 79 Fed. Reg. 34830.

utility to meet this cap by implementing measures such as energy conservation, using renewable energy, retiring units, or changing the sulfur content of the boiler fuel. The FIP requires Hawai'i Electric Light to comply with the cap by December 31, 2018.

Reciprocating Internal Combustion Engines National Emission Standards for Hazardous Air Pollutants (RICE NESHAP)

Hawai'i Electric Light and Maui Electric implemented steps to comply with the Reciprocating Internal Combustion Engines National Emission Standards for Hazardous Air Pollutants (RICE NESHAP) deadline of May 2013. The RICE NESHAP rule required retrofitting catalytic emission controls, crankcase ventilation filters, continuous parameter monitoring systems, and in some units switching to ultra low sulfur diesel (ULSD) fuel.

Toxic Substance Control Act (TSCA)

Former Moloka'i Electric Company Generation Site

The Toxic Substances Control Act of 1976 provides EPA with authority to require reporting, record-keeping and testing requirements, and restrictions relating to chemical substances and/or mixtures. Certain substances are generally excluded from TSCA, including, among others, food, drugs, cosmetics, and pesticides. TSCA addresses the production, importation, use, and disposal of specific chemicals including polychlorinated biphenyls (PCBs), asbestos, radon, and lead-based paint.

In 1989, Maui Electric acquired by merger Moloka'i Electric Company. Moloka'i Electric Company had sold its former generation site in 1983, but continued to operate under a lease until 1985. The EPA has since performed Brownfield assessments of the generation site that identified environmental impacts in the subsurface. Although operations there stopped four years before the merger in 1989, in discussions with the EPA and the State of Hawai'i Department of Health (DOH), Maui Electric agreed to conduct further investigations at the generation site and at an adjacent parcel that Moloka'i Electric Company had used for equipment storage to determine the extent of impacts of subsurface contaminants. A 2011 assessment by a Maui Electric contractor of the adjacent parcel identified environmental impacts, including elevated polychlorinated biphenyls (PCBs) in the subsurface soils. Maui Electric continues to investigate the generation site and the adjacent parcel to determine the extent of impacts of PCBs, fuel oils, and other subsurface contaminants. In March 2012, Maui Electric accrued an additional $3.1 million (reserve balance of $3.6 million as of March 31, 2013) for the additional investigation and estimated cleanup costs at the site and the adjacent parcel. Final costs of remediation, however, will depend on the results of the continued investigation.

National Pollutant Discharge Elimination System (NPDES)

Kahului Power Plant

EPA implements many of the Federal Clean Water Act (CWA) requirements through National Pollutant Discharge Elimination System (NPDES) permits. For example, the §316(a) thermal discharge requirements, §316(b) cooling water intake structure standards, and the categorical effluent standards are regulated through the NPDES permitting program. EPA is actively working on revising two CWA regulations that could have a significant impact on the design and operation of electric generating units: (1) the §316(b) cooling water intake structure regulations and (2) the Part 423 steam electric effluent guidelines.

The Kahului Power Plant receives water from underground aquifers, which means that §316(b) cooling water intake structure standards do not apply to the facility. Wastewater from the facility is discharged into the Pacific Ocean, which means the facility is required to maintain and comply with standards identified in its NPDES permit. Maui Electric has been informed that its next NPDES permit for Kahului Power Plant (Permit No. HI 0000094, ZM-37) will impose, for the first time, effluent limits for nutrients. Maui Electric has made the decision to retire the Kahului Power Plant since it will not be able to comply with the effluent limits, and therefore proposed a compliance schedule that is based upon ceasing regulated discharges.

6. Financial Impacts

The PSIP presents a Preferred Plan for the transformation of the Maui, Lana‘i, and Moloka‘i power systems.[44] The analyses used in the development of the Preferred Plan were based on numerous assumptions (discussed in Chapter 4 and summarized in Appendix F).[45]

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 Maui. 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

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44 Throughout the remainder of this chapter the use of the term "Maui" refers to all three systems.

45 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.

of customer affordability. Implicit in these financial analyses is the Company's ability to maintain affordable and ready access to capital markets.

RESIDENTIAL CUSTOMER BILL IMPACTS

The rate reform proposed in the DGIP[46] provides a rate design that reduces average monthly bills in real terms for average[47] residential full service[48] customers to approximately 28% 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.

If the current rate design continues, the projected monthly bill for an average[49] full service[50] residential customer is expected to decrease by approximately 24% from 2014 to 2030. This is in contrast to a potential 28% reduction in real terms of the monthly electricity bill for average full service residential customers under DG rate reform (see discussion in next section). The bill impact of investments made in the early years to transform the system is mitigated by the conversion of several assets to lower cost containerized liquefied natural gas (LNG) in 2017. Beginning in 2021, once future investments to transform the grid taper off, the average full service residential bill will decline throughout the remainder of the planning period to approximately 24% below 2014 levels, in real terms, by 2030.

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

47 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.

48 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.

49 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.

50 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.

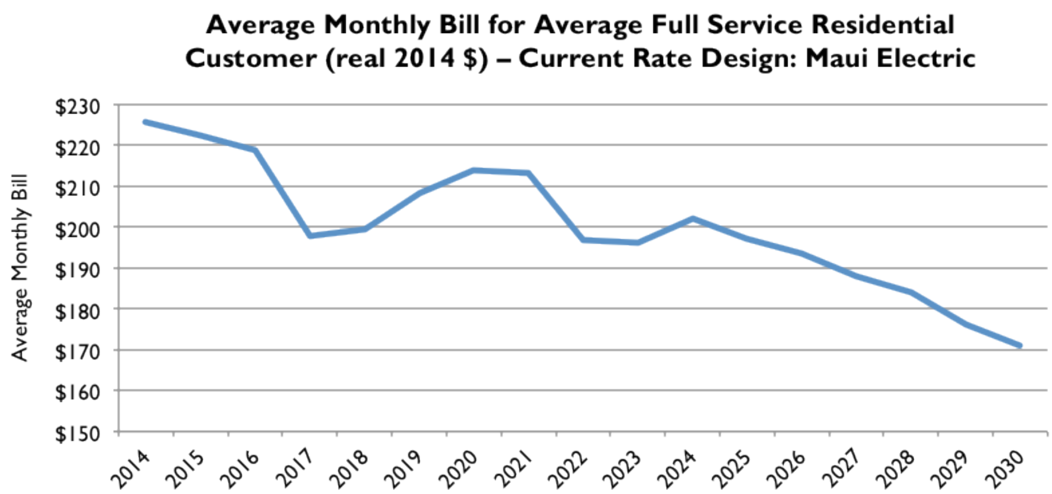

Figure 6-1. Average Full Service Residential Customer Bill Impact under Current Rate Design

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.

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.[51]

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, 28% lower in 2030 as compared to 2014 (that is, an additional 4% lower than under the current rate design) and more fairly allocates fixed grid costs across all customers.

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

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.
- 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	$50	n/a	n/a	n/a, within NEM energy balance, retail rate for any shortfall
DG 2.0 Customers	$50	$12	$0.20	Retail rate
Full Service Customers	$50	n/a	n/a	Retail rate

Table 6-1. Estimated Maui 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.[52] 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 Maui with DG-PV would grow by about 200% from approximately 4,500 at the end of 2013 to approximately 13,500 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.

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

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 28% in real terms over the 2014 to 2030 period.

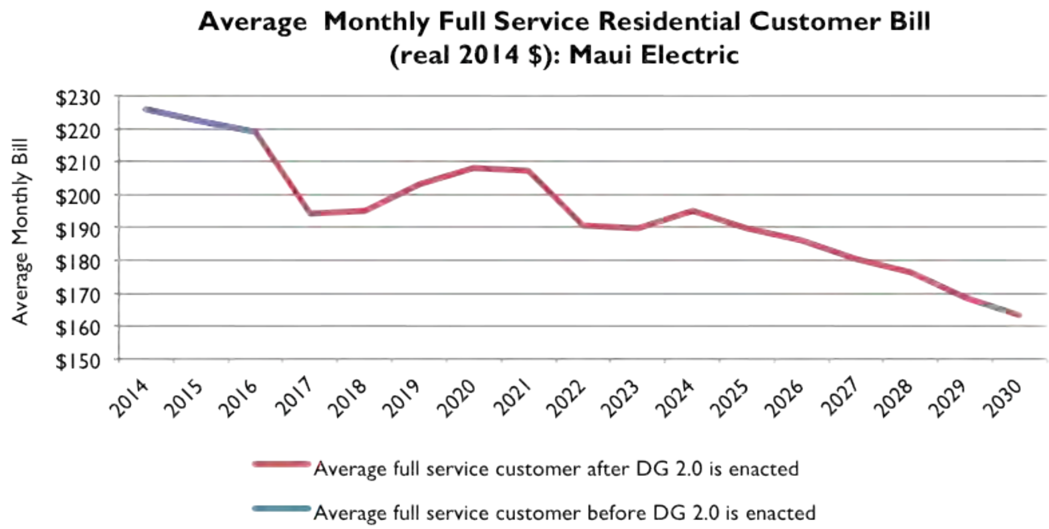

Figure 6-2. Average Full Service Residential Customer Bill Impact under DG 2.0

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.

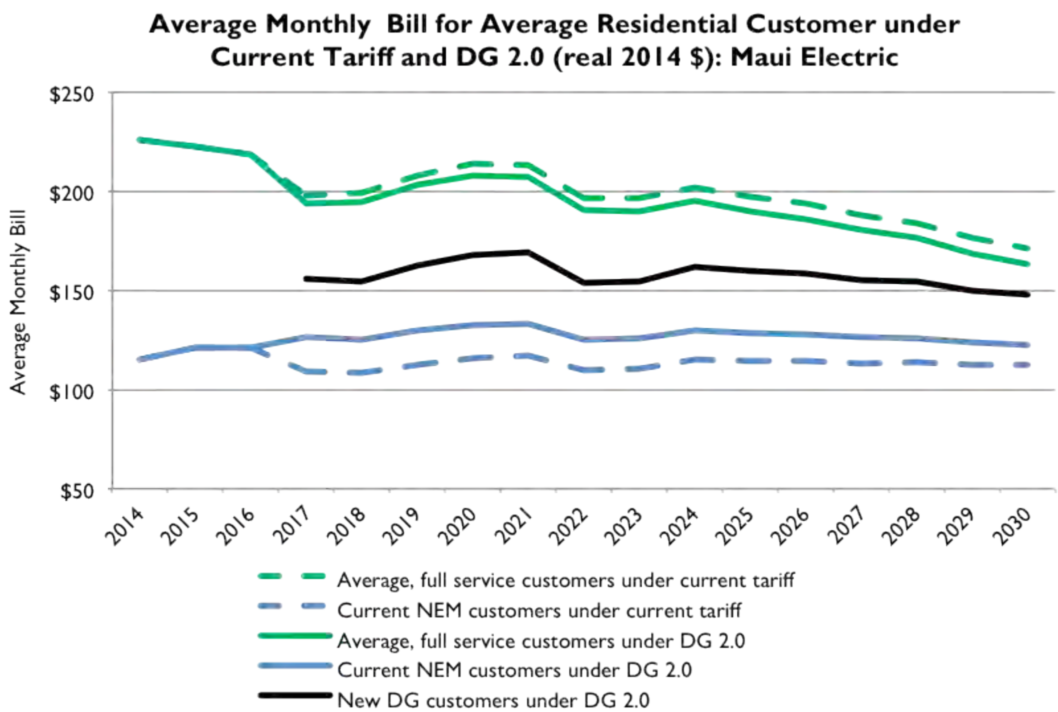

Figure 6-3. Average Residential Customer Bill Impact under Current Tariff and DG 2.0

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, provide additional options for customers to manage their energy costs, and more fairly allocate fixed grid costs across all customers while preserving an economic incentive for customers to opt for DG. 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 Hawaiʻi Electric Light: Figure 6-6).

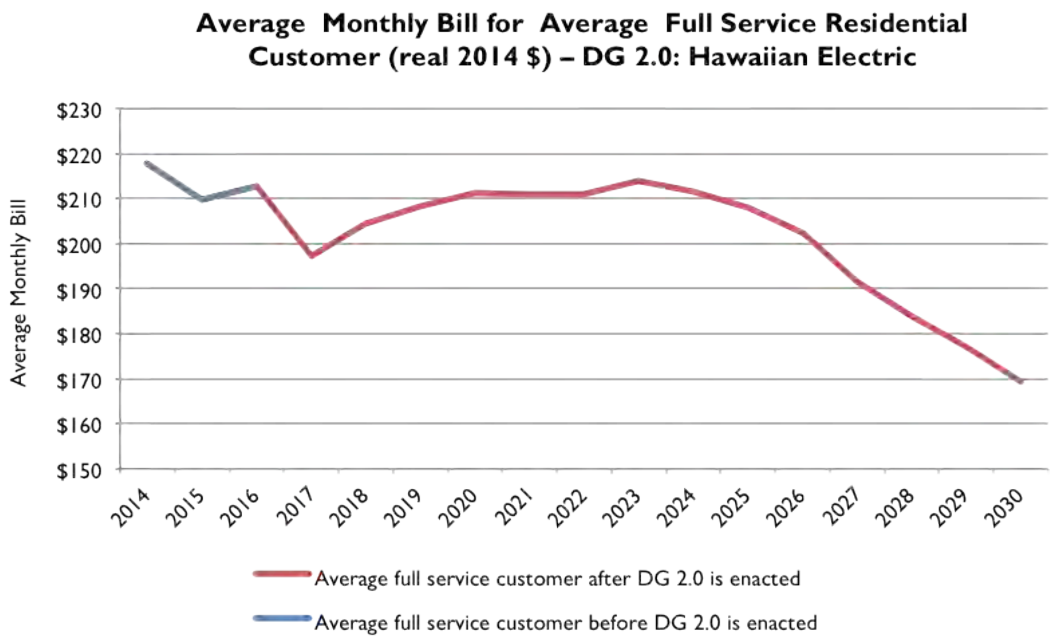

Figure 6-4. Average Monthly Bill for Average Full Service Residential Customer, Hawaiian Electric: DG 2.0

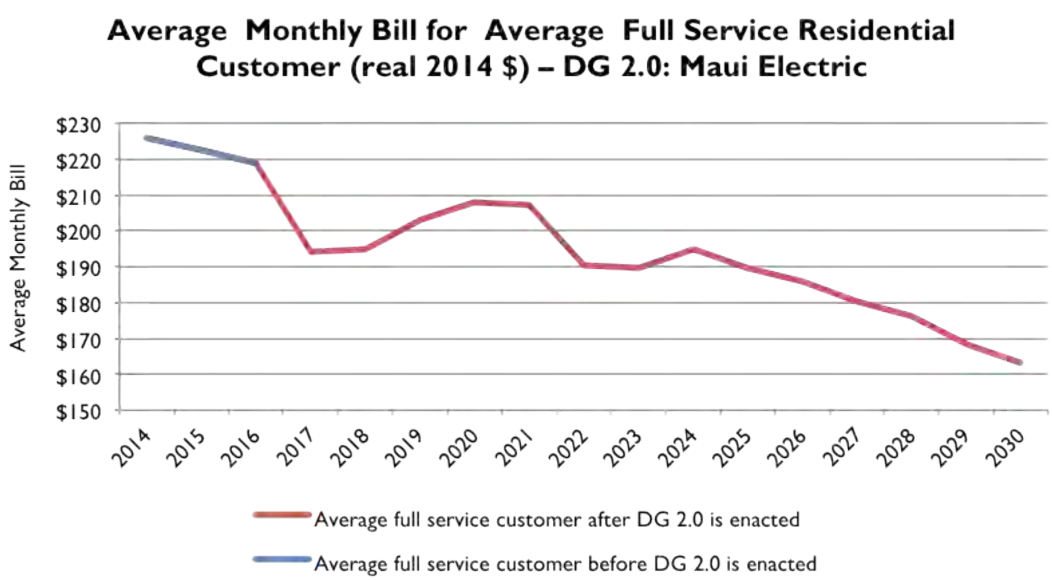

Figure 6-5. Average Monthly Bill for Average Full Service Residential Customer, Maui Electric: DG 2.0

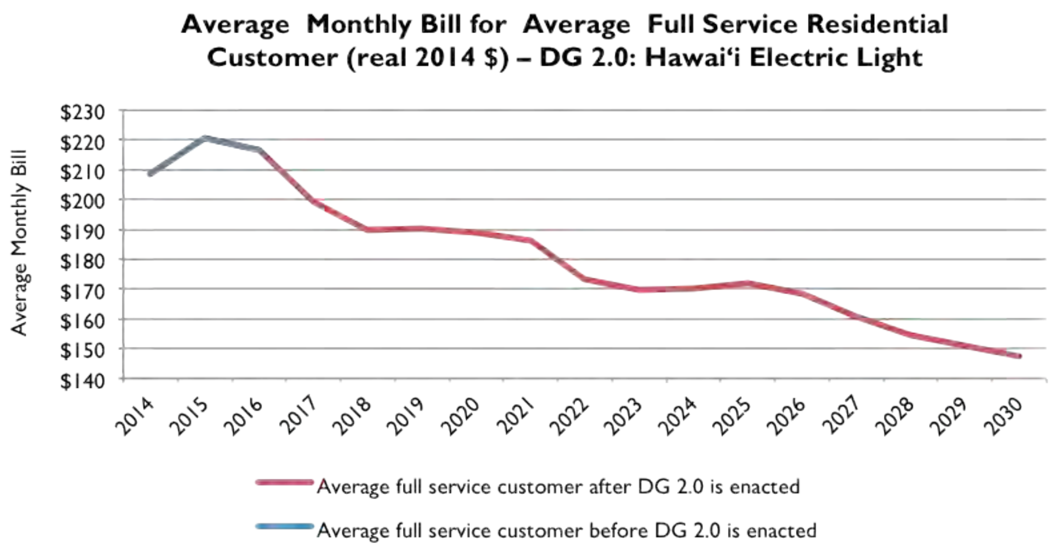

Figure 6-6. Average Monthly Bill for Average Full Service Residential Customer, Hawai'i Electric Light: DG 2.0

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[53], 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 $1.2 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 power expense
- Operations and maintenance expense

[53] 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 Maui revenue requirement remains unchanged from 2014 to 2021 in real terms (although the trend line reflects the introduction of LNG in the 2017 period), and then decreases significantly from 2021 forward, such that total revenue requirements are declining in real terms over the 2014 through 2030 period.

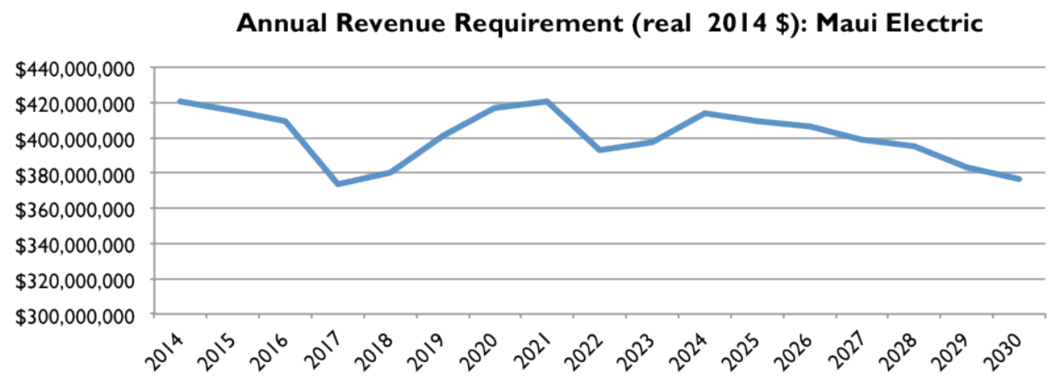

Figure 6-7. Maui Annual Revenue Requirement

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.

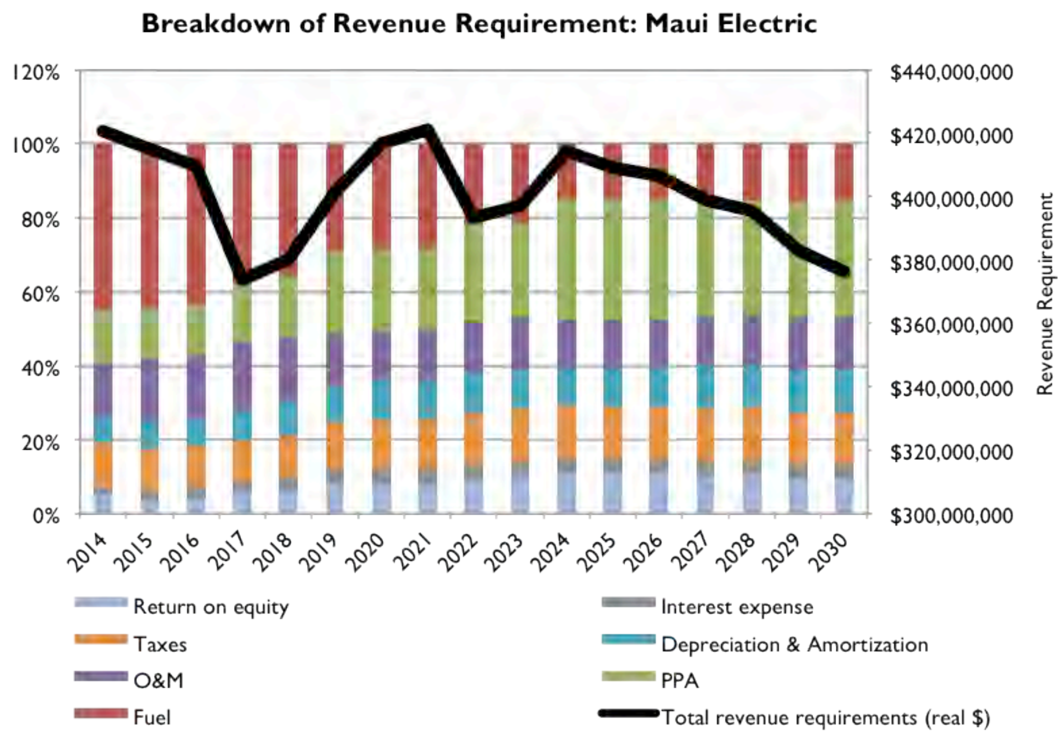

Figure 6-8. Maui Annual Revenue Requirement by Major Component

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 declines in real terms across the period, driven by the reductions in costs associated with Smart Grid and information technology investments.

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

Interest expense grows over the period, driven primarily by higher levels of investment.

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.

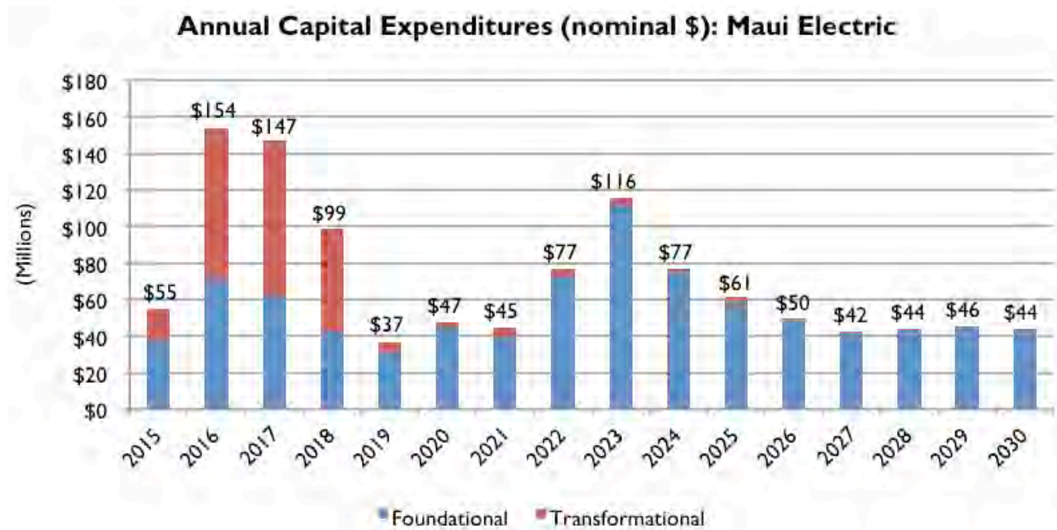

Figure 6-9. Maui Foundational and Transformational Capital Expenditures by Year

This profile reflects the basic fact that transformational investments need to be made in advance of each of major changes to the Maui, Lana‘i and Moloka‘i grids. 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.[54] One way it could be applied in Hawai‘i to lower revenue requirements and lower 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

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

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.

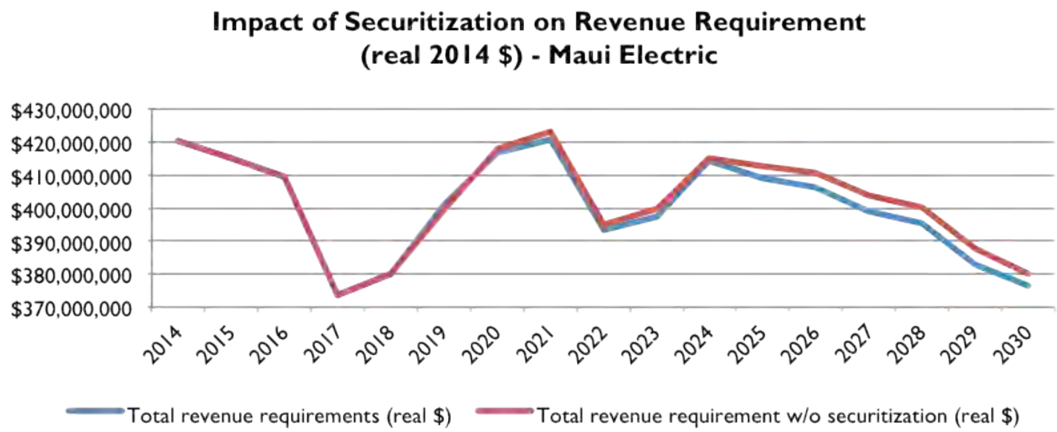

Figure 6-10. Impact of Securitization on Projected Maui Revenue Requirement

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 Maui, Lanaʻi and Molokaʻi. Under the current rate design, electricity bills for average full service residential customers will be reduced by 24% in real terms from 2014 levels by 2030 under the current tariff structure and by 28% under DG 2.0.

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)[55] 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.

[55] 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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